

## **Appendix 9H**

### **Tilden Mining Company BART Technical Analysis**

# West (Tilden) Analysis of Best Available Retrofit Technology (BART)

## Table of Contents

1. Executive Summary .....	v
2. Introduction.....	1
2.A BART Eligibility.....	2
2.B BART Determinations.....	3
3. Streamlined BART Analysis.....	8
3.A Indurating Furnaces.....	8
3.B PM-Only Taconite MACT Emission Units.....	9
3.C Other Combustion Units.....	9
4. Baseline Conditions and Visibility Impacts for BART Eligible Units .....	12
4.A MDEQ Subject-to-BART Modeling .....	12
4.B Facility Baseline Modeling .....	13
4.C Facility Baseline Modeling Results.....	15
5. BART Analysis for Indurating Furnaces .....	16
5.A Line 1 Indurating Furnace.....	16
5.A.i Sulfur Dioxide Controls .....	17
5.A.i.a STEP 1 – Identify All Available Retrofit Control Technologies.....	17
5.A.i.b STEP 2 – Eliminate Technically Infeasible Options .....	17
5.A.i.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	23
5.A.i.d STEP 4 – Evaluate Impacts and Document the Results .....	23
5.A.i.e STEP 5 – Evaluate Visibility Impacts .....	26
5.A.ii Nitrogen Oxide Controls .....	33
5.A.ii.a STEP 1 – Identify All Available Retrofit Control Technologies.....	33
5.A.ii.b STEP 2 – Eliminate Technically Infeasible Options .....	33
5.A.ii.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	46
5.A.ii.d STEP 4 – Evaluate Impacts and Document the Results .....	46
5.A.ii.e STEP 5 – Evaluate Visibility Impacts .....	49
5.B Process Boilers 1 and 2 .....	55
5.B.i Sulfur Dioxide Controls .....	55
5.B.i.a STEP 1 – Identify All Available Retrofit Control Technologies.....	55
5.B.i.b STEP 2 – Eliminate Technically Infeasible Options .....	55
5.B.i.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	59
5.B.i.d STEP 4 – Evaluate Impacts and Document the Results .....	59
5.B.i.e STEP 5 – Evaluate Visibility Impacts .....	61
5.B.ii Nitrogen Oxide Controls .....	62
5.B.ii.a STEP 1 – Identify All Available Retrofit Control Technologies.....	62

5.B.ii.b	STEP 2 – Eliminate Technically Infeasible Options .....	62
5.B.ii.c	STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	70
5.B.ii.d	STEP 4 – Evaluate Impacts and Document the Results .....	71
5.B.ii.e	STEP 5 – Evaluate Visibility Impacts .....	73
5.C	Line 1 Dryer .....	81
5.C.i	Sulfur Dioxide Controls .....	81
5.C.i.a	STEP 1 – Identify All Available Retrofit Control Technologies.....	81
5.C.i.b	STEP 2 – Eliminate Technically Infeasible Options .....	81
5.C.i.c	STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	87
5.C.i.d	STEP 4 – Evaluate Impacts and Document the Results .....	87
5.A.ii.f	STEP 5 – Evaluate Visibility Impacts .....	89
5.C.ii	Nitrogen Oxide Controls .....	90
5.C.ii.a	STEP 1 – Identify All Available Retrofit Control Technologies.....	90
5.C.ii.b	STEP 2 – Eliminate Technically Infeasible Options .....	90
5.C.ii.c	STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies .....	98
5.C.ii.d	STEP 4 – Evaluate Impacts and Document the Results .....	99
5.C.ii.e	STEP 5 – Evaluate Visibility Impacts .....	101
6.	Visibility Impacts.....	111
6.A	Post-Control Modeling Scenarios .....	111
6.B	Post-Control Modeling Results .....	111
7.	Select BART .....	128

### List of Tables

Table 3-1	Summary Table of BART-Eligible Units Subject to a Streamlined BART Analysis .....	11
Table 4-1	Baseline Conditions Modeling Input Data and the Basis for 24-hour Emissions Data .....	14
Table 4-2	Baseline Visibility Modeling Results.....	15
Table 5-1	Indurating Furnace SO <sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility .....	22
Table 5-2	Indurating Furnace SO <sub>2</sub> Control Technology Effectiveness.....	23
Table 5-3	Indurating Furnace SO <sub>2</sub> Control Cost Summary .....	24
Table 5-4	SO <sub>2</sub> Control Technology Impacts Assessment.....	25
Table 5-5	Post-Control Modeling Scenarios .....	27
Table 5-6	Post-Control SO <sub>2</sub> Modeling Scenarios - Modeling Input Data .....	29
Table 5-7	Post-Control SO <sub>2</sub> Modeling Scenarios - Visibility Modeling Results.....	31
Table 5-8	Post-Control SO <sub>2</sub> Modeling Scenarios - Visibility Improvements.....	32
Table 5-9	Indurating Furnace NO <sub>x</sub> Control Technology – Availability, Applicability, and Technical Feasibility .....	45

Table 5-10	Indurating Furnace NO <sub>x</sub> Control Technology Effectiveness .....	46
Table 5-11	Indurating Furnace NO <sub>x</sub> Control Cost Summary .....	47
Table 5-12	NO <sub>x</sub> Control Technology Impacts Assessment .....	48
Table 5-13	Post-Control NO <sub>x</sub> Modeling Scenarios.....	50
	Control Scenario .....	50
Table 5-14	Post-Control NO <sub>x</sub> Modeling Scenarios - Modeling Input Data.....	52
Table 5-15	Post-Control NO <sub>x</sub> Modeling Scenarios - Visibility Modeling Results .....	53
Table 5-16	Post-Control NO <sub>x</sub> Modeling Scenarios - Visibility Improvements .....	54
Table 5-17	Process Boiler SO <sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility .....	59
Table 5-18	Process Boiler SO <sub>2</sub> Control Technology Effectiveness.....	59
Table 5-219	Process Boilers 1 and 2 SO <sub>2</sub> Control Cost Summary .....	60
Table 5-20	Process Boilers 1 and 2 NO <sub>x</sub> Control Technology – Availability, Applicability and Technical Feasibility .....	70
Table 5-21	Backup Process Boiler NO <sub>x</sub> Control Technology Effectiveness.....	71
Table 5-22	Process Boiler NO <sub>x</sub> Control Cost Summary .....	72
Table 5-23	Process Boiler NO <sub>x</sub> Control Technology – Other Impacts Assessment .....	73
Table 5-27	Process Boiler Post-BART Modeling Scenarios.....	75
Table 5-28	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios - Modeling Input Data.....	78
Table 5-29	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios - Visibility Modeling Results ....	79
Table 5-30	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results .....	80
Table 5-29	Line 1 Dryer SO <sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility .....	87
Table 5-30	Line 1 Dryer SO <sub>2</sub> Control Technology Effectiveness .....	87
Table 5-31	Line 1 Dryer SO <sub>2</sub> Control Cost Summary .....	88
Table 5-32	Line 1 Dryer NO <sub>x</sub> Control Technology – Availability, Applicability and Technical Feasibility .....	98
Table 5-33	Line 1 Dryer NO <sub>x</sub> Control Technology Effectiveness.....	99
Table 5-34	Backup Process Boiler NO <sub>x</sub> Control Cost Summary.....	100
Table 5-35	Line 1 Dryer NO <sub>x</sub> Control Technology – Other Impacts Assessment.....	101
Table 5-36	Process Boiler Post-BART Modeling Scenarios.....	103
Table 5-37	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios - Modeling Input Data.....	108
Table 5-38	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios - Visibility Modeling Results ..	109
Table 5-39	Process Boiler Post-BART NO <sub>x</sub> Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results .....	110
Table 6-1	Post-Control Modeling Scenarios .....	113
Table 6-2	Post-Control NO <sub>x</sub> Modeling Scenarios - Modeling Input Data.....	118
Table 6-3	Post-Control Modeling Scenarios - Visibility Modeling Results.....	119
Table 6-4	Post-Control Modeling Scenarios - Visibility Modeling Results.....	120
Table 6-5	Post-Control Modeling Results – Dollars per Deciview Improvement.....	121

## **List of Appendices**

- Appendix A Control Cost Analysis Spreadsheets
- Appendix B Changes to MDEQ BART Modeling Protocol
- Appendix C Visibility Impacts Modeling Report
- Appendix D Applicable and Available Retrofit Technologies
- Appendix E Clean Air Interstate Rule (CAIR), Cost-Effective Air Pollution Controls
- Appendix F BART Analysis Procedure and Streamlined BART Approach

# 1. Executive Summary

---

## DRAFT LANGUAGE

Tilden Mining Company LC (Tilden) owns and operates an iron mining facility near Ishpeming, Michigan in Marquette County. This report describes the background and methods for the selection of the Best Available Retrofit Technology (BART) as proposed by Tilden for its taconite processing plant located near Ishpeming, MI.

Michigan Department of Environmental Quality (MDEQ) identified the six pieces of equipment that were installed within the time window (1962-1977) that makes them subject to BART. The equipment includes Line 1 Kiln, Dryer, Cooler, Primary Crusher, and Process Boilers 1 and 2. Line 1 Kiln is permitted for natural gas, coal and fuel oil and Line 1 Dryer, Process Boilers 1 and 2 are permitted for natural gas and fuel oil. Preliminary visibility modeling conducted by the MDEQ found that air emissions from Tilden's facility "cause or contribute to visibility impairment" in a federally protected Class I area, therefore making the facility subject to BART.

Guidelines included in 40 CFR §51 Appendix Y were used to propose BART for the subject units. The existing pollution control equipment includes wet scrubbers on the dryer, cooler, and primary crusher, which are designed to control particulate matter (PM). The wet scrubber on the dryer will, however, experience some collateral control of sulfur dioxide (SO<sub>2</sub>). The kiln PM is controlled with an electrostatic precipitator (dry). A dispersion modeling sequence of CALMET, CALPUFF, and CALPOST was used to assess the visibility impacts of the baseline emissions and after the application of candidate BART controls. Visibility impacts were evaluated in the selection of BART. Other criteria that the BART rules require to be considered include the availability of technology, costs of compliance, energy and environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Based on consideration of all of the above criteria, Tilden proposes the following as BART:

### Line 1 Kiln

- SO<sub>2</sub> emissions of 28,000 lb per day for Line 1 when coal is burned
- NO<sub>x</sub> limit as specified in Appendix 2 Schedule of Compliance in the Renewable Operating Permit 199600379 and with Rule 336.1801.

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard<sup>1</sup>.

#### Line 1 Cooler

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard<sup>2</sup>.

#### Boilers 1 and 2

- SO<sub>2</sub> emissions limit is regulated by limiting the sulfur content to 1.2% by weight, calculated on the basis on 18,000 BTU per pound when used oil is burned.
- NO<sub>x</sub> is good combustion practices
- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard<sup>3</sup>.

#### Line 1 Dryer

- SO<sub>2</sub> emissions limit is regulated by limiting the sulfur content to 1.5% by weight, calculated on the basis on 18,000 BTU per pound when used oil is burned NO<sub>x</sub> emissions will be controlled
- NO<sub>x</sub> is good combustion practices
- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard<sup>4</sup>.

#### Primary Crusher

---

<sup>1</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

<sup>2</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

<sup>3</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

<sup>4</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard<sup>5</sup>.

CALPUFF model is conservative, resulting in an over prediction of impacts. This modeled high impact from the BART eligible sources is 0.72 dV, which is below perceptible levels of one to two dV. Real impacts to the Class I areas from Tilden are expected to be even less than these modeled impacts.

---

<sup>5</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

## 2. Introduction

---

Tilden Mining Company LC (Tilden) owns and operates an iron mining facility near Ishpeming, Michigan in Marquette County. This report describes the background and methods for the selection of the Best Available Retrofit Technology (BART) as proposed by Tilden for its taconite processing plant also located near Ishpeming, MI.

To meet the Clean Air Act's requirements, the U.S. Environmental Protection Agency (U.S. EPA) published regulations to address visibility impairment in our nation's largest national parks and wilderness ("Class I") areas in July 1999. This rule is commonly known as the "Regional Haze Rule" [64 Fed. Reg. 35714 (July, 1999) and 70 Fed. Reg. 39104 (July 6, 2005)] and is found in 40 CFR part 51, in 51.300 through 51.309.

Within its boundary, Michigan has two Class I areas – the Isle Royale National Park (IRNP) and Seney Wilderness Area. By December 2007, MDEQ must submit to U.S. EPA a Regional Haze State Implementation Plan (SIP) that identifies sources that cause or contribute to visibility impairment in these areas. The Regional Haze SIP must also include a demonstration of reasonable progress toward reaching the 2018 visibility goal for each of the state's Class I areas.

One of the provisions of the Regional Haze Rule is that certain large stationary sources that were put in place between 1962 and 1977 must conduct a Best Available Retrofit Technology (BART) analysis. The purpose of the BART analysis is to analyze available retrofit control technologies to determine if a technology should be installed to improve visibility in Class I areas. The chosen technology is referred to as the BART controls, or simply BART. The SIP must require BART on all BART-eligible sources and mandate a plan to achieve natural background visibility by 2064. The SIP must also include milestones for establishing reasonable progress towards the visibility improvement goals and plans for the first five-year period. Upon submission of the Regional Haze SIP, states must make the requirements for BART sources enforceable through rules, administrative orders or Title V permit amendments.

By U.S. EPA's definition, reasonable progress means that there is no degradation of the 20 best-visibility days, and the 20 worst-visibility days must have no more visibility impairment than the 20

worst days under natural conditions by 2064.<sup>6</sup> Assuming a uniform rate of progress, the default glide path would require 1 to 2 percent improvement per year in visibility on the 20 worst days. The state must submit progress reports every five years to establish their advancement toward the Class I area natural visibility backgrounds. If a state feels it may be unable to adopt the default glide path, a slower rate of improvement may be proposed on the basis of cost or time required for compliance and non-air quality impacts.

Note that the improvements required under the Regional Haze regulations are different from the BART requirements. Facilities subject to BART are **not** required to make all of the reasonable progress towards improving regional haze in Class I areas. Rather, BART is but one of many measures which states may rely upon in making “reasonable progress” towards regional haze improvement goals.

## **2.A BART Eligibility**

BART eligibility is established on the basis on three criteria. In order to be BART-eligible, sources must meet the following three conditions:

1. Contain emission units in one or more of the 26 listed source categories under the PSD rules (e.g., taconite ore processing plants, fossil-fuel-fired steam electric plants larger than 250 MMBtu/hr, fossil-fuel boilers larger than 250 MMBtu/hr, petroleum refineries, coal cleaning plants, sulfur recovery plants, etc.);
2. Were in existence on August 7, 1977, but were not in operation before August 7, 1962;
3. Have total potential emissions greater than 250 tons per year for at least one visibility-impairing pollutant from the emission units meeting the two criteria above.

Under the BART rules, large sources that have previously installed pollution-control equipment required under another standard (e.g., MACT, NSPS and BACT) will be required to conduct visibility analyses. Installation of additional controls may be required to further reduce emissions of visibility impairing pollutants such as PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, and possibly Volatile Organic Compounds (VOCs) and ammonia. Sources built before the implementation of the Clean Air Act (CAA), which had previously been grandfathered, may also have to conduct such analyses and

---

<sup>6</sup> 70 FR No. 178 pp. 39104 to 39172.

possibly install controls, even though they have been exempted to date from any other CAA requirements.

Once BART eligibility is determined, a source must then determine if it is “subject to BART.” A source is subject to BART if emissions “cause or contribute” to visibility impairment at any Class I area. Visibility modeling conducted with CALPUFF or another U.S. EPA -approved visibility model is necessary to make a definitive visibility impairment determination (>0.5 deciviews). Sources that do not cause or contribute to visibility impairment are exempt from BART requirements, even if they are BART-eligible.

## **2.B BART Determinations**

Each source that is subject to BART must determine BART on a case-by-case basis. Even if a source was previously part of a group BART determination, individual BART determinations must be made for each source. The BART analysis takes into account six criteria and is analyzed using five steps. The six criteria that comprise the engineering analysis include: the availability of the control technology, existing controls at a facility, the cost of compliance, the remaining useful life of a source, the energy and non-air quality environmental impacts of the technology, and the visibility impacts.<sup>7</sup> The five steps of a BART analysis are:

### ***Step 1 - Identify all Available Retrofit Control Technologies***

The first step in the analysis is to identify all retrofit control technologies which are generally available for each applicable emission unit. Available retrofit control technologies are defined by U.S. EPA in Appendix Y to Part 51 (Guidelines for BART Determinations under the Regional Haze Rule) as follows:

*Available retrofit technologies 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. Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives. The control alternatives can 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 or gas*

---

<sup>7</sup> 40 CFR 51 Appendix Y

*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 been demonstrated in practice.<sup>8</sup>*

**Step 2 - Eliminate Technically Infeasible Options**

In the second step, the source-specific technical feasibility of each control option identified in step one is evaluated by answering three specific questions:

- a. Is the control technology “available” to the specific source which is undergoing the BART analysis?

The U.S. EPA states that a control technique is considered “available” to a specific source “if it has reached the stage of licensing and commercial availability.<sup>9</sup>”

However, the U.S. EPA further states that they “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.<sup>10</sup>”

- b. Is the control technology an “applicable technology” for the specific source which is undergoing the BART analysis?

In general, a commercially available control technology, as defined in question 1, “will be presumed applicable if it has been used on the same or a similar source type.<sup>11</sup>” If a control technology has not been demonstrated on a same or a similar source type, the technical feasibility is determined by “examining the physical and chemical characteristics of the pollutant-bearing stream and comparing them to the gas stream characteristics of the source types to which the technology has been applied previously.<sup>12</sup>”

- c. Are there source-specific issues/conditions that would make the control technology not technically feasible?

---

<sup>8</sup> Federal Register 70, No. 128 (July 6, 2005): 39164

<sup>9</sup> Federal Register 70, No. 128 (July 6, 2005): 39165

<sup>10</sup> IBID

<sup>11</sup> IBID

<sup>12</sup> IBID

This question addresses specific circumstances that “preclude its application to a particular emission unit.” This demonstration typically includes an “evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology<sup>13</sup>.” This also involves the identification of “irresolvable technical difficulties.” However, when the technical difficulties are merely a matter of increased cost, the technology should be considered technically feasible and the technological difficulty evaluated as part of the economic analysis<sup>14</sup>.

It is also important to note that vendor guarantees can provide an indication of technical feasibility but the U.S. EPA does not “consider a vendor guarantee alone to be sufficient justification that a control option will work.” Conversely, the U.S. EPA does not consider the absence of a vendor guarantee to be a “sufficient justification that a control option or emission limit is technically infeasible”. In general, the decisions on technical feasibility should be based on a combination of the evaluation of the chemical and engineering analysis and the information from vendor guarantees<sup>15</sup>.

***Step 3 - Evaluate Control Effectiveness***

In step three, the remaining controls are ranked based on the control efficiency at the expected emission rate (post-control) as compared to the emission rate before addition of controls (pre-BART) for the pollutant of concern.

***Step 4 - Evaluate Impacts and Document Results***

In the fourth step, an engineering analysis documents the impacts of each remaining control technology option. The economic analysis compares dollar per ton of pollutant removed for each technology. In addition it includes incremental dollar per ton cost analysis to illustrate the economic effectiveness of one technology in relation to the others. Finally, Step Four includes an assessment of energy impacts and other non-air quality environmental impacts.

Economic impacts were analyzed using the procedures found in the U.S. EPA Air Pollution Control Cost Manual – Sixth Edition (EPA 452/B-02-001). Equipment cost estimates from the U.S. EPA Air Pollution Control Cost Manual or U.S. EPA’s Air

---

<sup>13</sup> IBID

<sup>14</sup> IBID

<sup>15</sup> IBID

Compliance Advisor (ACA) Air Pollution Control Technology Evaluation Model version 7.5 were used. Vendor cost estimates for this project were used when applicable. The source of the control equipment cost data are noted in each of the control cost analysis worksheets as found in Appendix A.

***Step 5 - Evaluate Visibility Impacts***

The fifth step requires a modeling analysis conducted with U.S. EPA -approved models such as CALPUFF. The modeling protocol<sup>16</sup>, including receptor grid, meteorological data, and other factors used for this part of the analysis were provided by the Michigan Department of Environmental Quality (MDEQ). The model outputs, including the 98th percentile dV value and the number of days the facility contributes more than a 0.5 deciview (dV) of visibility impairment at each of the Class I areas, are used to establish the degree of improvement that can be reasonably attributed to each technology.

The final step in the BART analysis is to select the “best” alternative using the results of steps 1 through 5. In addition, the U.S. EPA guidance states that the “affordability” of the controls should be considered, and specifically states:

- 1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of plant operations.*
- 2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have severe impacts on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether competing*

---

<sup>16</sup> Single Source Modeling to Support Regional Haze BART Modeling Protocol, March 21, 2006, Lake Michigan Air Directors Consortium.

*plants in the same industry have been required to install BART controls if this information is available.*<sup>17</sup>

To complete the BART process, the analysis must “establish enforceable emission limits that reflect the BART requirements and requires compliance within a reasonable period of time<sup>18</sup>.” Those limits must be developed for inclusion in the state implementation plan (SIP) that is due to U.S. EPA in December of 2007. In addition, the analysis must include requirements that the source “employ techniques that ensure compliance on a continuous basis<sup>19</sup>.” which could include the incorporation of other regulatory requirements for the source, including Compliance Assurance Monitoring (40 CFR 64), Periodic Monitoring (40 CFR 70.6(a)(3)) and Sufficiency Monitoring (40 CFR 70(6)(c)(1)). If technological or economic limitations make measurement methodology for an emission unit infeasible, the BART limit can “instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards<sup>20</sup>.”

Compliance with the BART emission limits will be required within 5 years of U.S. EPA approval of the Michigan SIP.

---

<sup>17</sup> 40 CFR 51 Appendix Y. Page 361.

<sup>18</sup> 40 CFR 51 Appendix Y. Page 368.

<sup>19</sup> 40 CFR 51 Appendix Y. Page 369.

<sup>20</sup> 40 CFR 51 Appendix Y. Page 368.

## 3. Streamlined BART Analysis

---

Within the preamble to the final federal BART rule, U.S. EPA explicitly encouraged states to include a streamlined approach for BART analyses<sup>21</sup>. The streamlined approach will allow both states and the facilities to focus their resources on the main contributors to visibility impairment. This section of the report follows the MDEQ-approved streamlined BART analysis for taconite facilities and presents the results of the streamlined approach in Table 3-1.

### 3.A Indurating Furnaces

The indurating furnaces are sources of three visibility impairing pollutants: NO<sub>x</sub>, SO<sub>2</sub>, and PM. Relative to NO<sub>x</sub> and SO<sub>2</sub>, PM is not a major visibility impairing pollutant. Further, the indurating furnaces are subject to the taconite MACT standard<sup>22</sup> for the PM emissions. MDEQ requested that Tilden submit a BART analysis approach August 31, 2006. Tilden submitted both the BART Analysis Procedures and Streamlined BART Approach on August 29, 2006. Tilden has performed the BART analysis as outlined in the August 29, 2006 submittals. The BART Analysis Procedures and Streamlined BART Approach dated August 29, 2006 is included in Appendix F for reference.

The approach, as outlined in the August 29, 2006 Streamlined BART Approach, relies on MACT standards to represent BART level of control for those visibility impairing pollutants addressed by the MACT standard unless there are new technologies subsequent to the MACT standard, which would lead to cost-effective increases in the level of control. Specifically in 40 CFR Part 51 Appendix Y paragraph IV.C., it states:

*For VOC and PM sources subject to MACT standards, States may streamline the analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards. We believe that there are many VOC and PM sources that are well controlled because they are regulated by the MACT standards, which EPA developed under CAA section 112. For a few MACT standards, this may also be true for SO<sub>2</sub>. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. Examples of these hazardous air pollutant sources which effectively control VOC and PM emissions include (among others) secondary lead facilities, organic chemical plants subject to the hazardous organic NESHAP*

---

<sup>21</sup> Federal Register 70, no. 128 (July 6, 2005): 39107 and 39116

<sup>22</sup> 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing

*(HON), pharmaceutical production facilities, and equipment leaks and wastewater operations at petroleum refineries. We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. **Unless there are new technologies subsequent to the MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART.** (emphasis added)*

It is clear from EPA's guidance that they are encouraging states to develop a streamlined BART analysis approach for sources regulated under a MACT. Since the Taconite MACT standard was established very recently and becomes effective in 2006, the technology analysis is up-to-date. As a result, BART will be presumed to be equivalent to MACT for PM.

A full BART analysis will be conducted for NO<sub>x</sub> and SO<sub>2</sub> where applicable.

### **3.B PM-Only Taconite MACT Emission Units**

In addition to the indurating furnaces, the taconite MACT standard also regulates PM emissions from Ore Crushing and Pellet Cooler operations. These sources operate near ambient temperature, only emit PM, and do not emit NO<sub>x</sub> or SO<sub>2</sub>. The Ore Crushing source operates with control equipment to meet the applicable MACT limits (0.008 gr/dscf for existing sources and 0.005 gr/dscf for new sources). The Pellet Cooler sources are excluded from additional control under the MACT standard due to *the large size of the particles and the relatively low concentration of particle emissions* [FR, December 18, 2002, page 77570]. Therefore, the emissions from the pellet coolers are considered to have a negligible impact on visibility impairment, and no control requirements under the MACT standard is consistent with the intention of the BART analysis.

Since the MACT standard was established recently and became effective in October 31, 2006, the technology analysis is up-to-date. Again, for these units subject to a MACT standard, BART will be presumed to be equivalent to MACT according to Streamlined BART Procedures submitted to MDEQ August 29, 2006.

No further analysis will be required to establish BART for these sources.

### **3.C Other Combustion Units**

The combustion units are sources of three visibility impairing pollutants: NO<sub>x</sub>, SO<sub>2</sub>, and PM.

Tilden facility has two process boilers that are subject to the boiler MACT<sup>23</sup>. Since the boiler MACT standards were established recently and become effective in 2007, the technology analysis is up-to-date. For the units subject to the boiler MACT standard, BART will be presumed to be equivalent to MACT for PM according to Streamlined BART Procedures submitted to MDEQ August 29, 2006

Similar to the induration furnaces, the dryer is also subject to the Taconite MACT for PM. As a result, BART will be presumed to be equivalent to MACT for PM.

A full BART analysis will be conducted for NO<sub>x</sub> and SO<sub>2</sub> where applicable for the process boilers and dryer.

---

<sup>23</sup> 40 CFR 63 Subpart DDDDD-NESHAPS: ICI Boilers and Process Heaters

**Table 3-1 Summary Table of BART-Eligible Units Subject to a Streamlined BART Analysis**

<b>Emission Unit #</b>	<b>Emission Unit Description</b>	<b>NO<sub>x</sub> Max 24-hr Actual Emissions (lbs/day)</b>	<b>SO<sub>2</sub> Max 24-hr Actual Emissions (lbs/day)</b>	<b>PM<sub>10</sub> Max 24-hr Actual Emissions (lbs/day)</b>	<b>MACT PM Emission Limit (gr/dscf)</b>	<b>Stack Number</b>	<b>Actions Required</b>
<b>3.A Indurating Furnace</b>							
EUKILN1	Line 1 Indurating Furnace	26208.0	6552.0	4948.5	0.01 magnetite 0.03 hematite	SVP0051711 (South) and SVP0051981 (North)	Full BART Analysis for SO <sub>2</sub> and NO <sub>x</sub>
<b>3.B PM-Only Taconite MACT Emission Units</b>							
EUPRIMARY CRUSHER	Primary Crusher 1	--	--	25.7	0.008	SVA0011570	None
EUCOOLER1	Line 1 Pellet Cooler Exhaust	--	--	5.9	0.008	SVP0025490	None
<b>3.C Other Combustion Units</b>							
EUDRYER1	Line 1 Dryer	88.3	199.2	529.0	0.6 <sup>1</sup>	SVP0082951	Full BART Analysis for SO <sub>2</sub> and NO <sub>x</sub>
EUBOILER1	Process Boiler #1	463.3	1.5	300.0	0.6 <sup>1</sup>	SVBLR.STK. T1	Full BART Analysis for SO <sub>2</sub> and NO <sub>x</sub>
EUBOILER2	Process Boiler #2	463.3	1.5	300.0	0.6 <sup>1</sup>	SVBLR.STK. T1	Full BART Analysis for SO <sub>2</sub> and NO <sub>x</sub>

<sup>1</sup>PM – Filterable PM only as measured by U.S. EPA Method 5 including the applicable averaging and grouping provisions, as presented in the MACT regulation, effective 10/30/2006.

## 4. Baseline Conditions and Visibility Impacts for BART Eligible Units

---

As indicated in U.S. EPA's final BART guidance<sup>24</sup>, one of the factors to consider when determining BART for an individual source is the degree of visibility improvement resulting from the retrofit technology. The visibility impacts for this facility were estimated using CALPUFF, an U.S. EPA approved model recommended for comparing the visibility improvements of different retrofit control alternatives. However it is important to note that CALPUFF is a conservative model that over estimates real impacts. Therefore, although the CALPUFF baseline modeling results are important to comparing control alternatives on a relative basis they do not accurately predict real impacts.

The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, PM<sub>10</sub>, and background ammonia can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts.

In order to estimate the visibility improvement resulting from the retrofit technology, the source must first be modeled at baseline conditions. Per U.S. EPA guidance, the baseline, or pre-BART conditions, shall represent the average emission rate in units of pounds per hour (lbs/hr) and reflect the maximum 24-hour actual emissions<sup>25</sup>.

### 4.A MDEQ Subject-to-BART Modeling

In order to determine which sources are "Subject-to-BART" in the state of Michigan, the MDEQ completed modeling of the BART-eligible emission units at various facilities in Michigan in accordance with the Regional Haze Rule. The modeling by MDEQ was conducted using CALPUFF, as detailed in the "Single Source Modeling to Support Regional Haze BART Modeling Protocol", March 21, 2006, Lake Michigan Air Directors Consortium. The modeling by MDEQ was conducted using emission rate information submitted by the facility in the annual emissions reporting. The emissions were reported in units of pounds per year and divided by the annual hours per year of operation to calculate a pound per hour (lb/hr) emission rate. The lb/hr emission rate was then multiplied by 24 hours to calculate the pounds per day (lb/day) emission rate. The lb/day is to reflect

---

<sup>24</sup> Federal Register 70, no. 128 (July 6, 2005): 39106.

<sup>25</sup> 40 CFR Part 51 Appendix Y

the maximum actual emissions during a 24-hour period under steady-state operating conditions during periods of high capacity utilization. The modeling conducted by MDEQ demonstrated that this facility is subject-to-BART as stated in the letter from MDEQ on March 17, 2006

## **4.B Facility Baseline Modeling**

Prior to re-creating the MDEQ visibility impairment model, the modeling method was re-evaluated. On behalf of Tilden and Empire, Barr Engineering proposed changes to the modeling. In discussions with MDEQ, it was indicated that most aspects of the modeling were flexible, so long as the changes were documented and appropriate files were included for their review with submittal of results. Details of the modifications to the model are included in Appendix B.

In addition, the maximum 24-hour emission rates were re-evaluated internally within Tilden to verify that the emission rates represent the maximum steady-state operating conditions during periods of high capacity utilization. The maximum 24-hour emission rates were adjusted to reflect combustion of permitted fuels.

The original baseline emissions were modeled for comparison to MDEQ results. This data is summarized in Table 4-1. The full modeling analysis is presented in Appendix C.

**Table 4-1 Baseline Conditions Modeling Input Data and the Basis for 24-hour Emissions Data**

Emission Unit ID	Emission Unit Description	SO2 Max. 24-hr Actual Emissions (lb/day)	Basis for SO2 24-hr Actual Emissions	NOx Max. 24-hr Actual Emissions (lb/day)	Basis for NOx 24-hr Actual Emissions	PM2.5 Max. 24-hr Actual Emissions (lb/day)	Basis for PM2.5 24-hr Actual Emissions	PM10 Max. 24-hr Actual Emissions (lb/day)	Basis for PM10 24-hr Actual Emissions	Stack No.	Latitude	Longitude	Height of opening from ground (ft)	Base Elevation of Ground (ft)	Stack length, width or Diameter (ft)	Flow Rate at Exit (acfm)	Exit Gas Temperature (F)
3.A	Indurating Furnaces																
EUKLN1	Line 1 Pellet Induration	6552.0	COAL	26,208.0	Nat gas			3,610.1	MACT	SVP0051981	46.44084994	-87.65340738	240	1474	19.3	842,000	300
								1,338.4	MACT	SVP0051711	46.44075383	-87.65132336	160	1474	13.5	306,000	300
3.B	PM-Only Taconite MACT Emission Units																
EUPRIMARYCRUSHER	PRIMARY CRUSHER							25.7	MACT	SVA0011570	46.43933071	-87.65152770	15	1474	2.5	15,400	60
EUCOOLER	Line 1 Cooler							5.9	MACT	SVP0025490	46.43979916	-87.64827887	151	1474	14.0	786,000	333
3.C	PM-Only Other Combustion MACT Emission Units																
EUDRYER1	Line 1 Dryer	199.2	COAL	88.3	NAT. GAS			529.0	MACT	SVP0082951	46.44075383	-87.65132336	119	1474	6.3	57,135	150
EUBOILER1	Process Boiler #1	1.5	FUEL OIL	463.3	NAT. GAS			300.0	MACT	SVBLR.STK.T1	46.44091784	-87.65412418	130	1474	7.5	192,000	350
EUBOILER2	Process Boiler #2	1.5	FUEL OIL	463.3	NAT. GAS			300.0	MACT	SVBLR.STK.T1	46.44091784	-87.65412418	130	1474	7.5	192,000	350

## 4.C Facility Baseline Modeling Results

The Michigan BART modeling protocol<sup>26</sup> describes the CALPUFF model inputs, including the meteorological data set and background atmospheric ammonia and ozone concentrations, along with the functions of the CALPOST post processing. The CALPOST output files provide the following two methods to assess the expected post-control visibility improvement:

- 98<sup>th</sup> Percentile: As defined by federal guidance, a source "contributes to visibility impairment" if the 98<sup>th</sup> percentile of any year's modeling results (i.e. 7<sup>th</sup> highest day) meets or exceeds the threshold of five-tenths (0.5) of a deciview (dV) at a Federally protected Class I area receptor.
- Number of Days Exceeding 0.5 dV: The severity of the visibility impairment contribution, or reasonably attributed visibility impairment, can be gauged by assessing the number of days on which a source exceeds a visibility impairment threshold of 0.5 dV.

A summary of the baseline visibility modeling is presented in Table 4-2. As illustrated in the table, this facility is considered to contribute to visibility impairment in Class I areas because the modeled 98<sup>th</sup> percentile of the baseline conditions exceeds the threshold of 0.5 dV. The results of this modeling are also utilized in the post-control modeling analysis in section 6 of this document. The full modeling analysis is presented in Appendix C.

**Table 4-2 Baseline Visibility Modeling Results**

Class I Area with Greatest Impact	2002		2003		2004		2002 – 2004 Combined	
	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview
IRNP	0.714	19	0.722	11	0.599	11	0.674	41

<sup>26</sup> Single Source Modeling to Support Regional Haze BART Modeling Protocol, March 21, 2006, Lake Michigan Air Directors Consortium. Page 3.

## 5. BART Analysis for Indurating Furnaces

---

As presented in section 3 and Table 3-1, the following sources at Tilden require a full BART analysis for SO<sub>2</sub> and NO<sub>x</sub>:

- Line 1 Indurating Furnace;
- Process Boilers 1 and 2; and
- Line 1 Dryer.

The BART analyses for these sources are presented in sections 5.A, 5.B, and 5.C, respectively.

### 5.A Line 1 Indurating Furnace

The primary function of taconite indurating furnaces is to convert magnetic or hematite iron concentrate to a more highly oxidized iron in the form of a pellet that is sold to metallic iron and steel production facilities. “Soft” or “green” pellets are oxidized and heat-hardened in the induration furnace. The induration process involves pellet pre-heating, drying, hardening, oxidation and cooling. The process requires large amounts of air for pellet oxidation and cooling. Process temperature control in all parts of the furnace is critical to minimize product breakage in the initial process stages, allow required oxidation reactions to occur, and adequately cool the product prior to subsequent handling steps. Directed air flow, heat recovery and fuel combustion are critical to controlling temperature and product quality in all parts of the furnace.

The Line 1 Indurating Furnace is a grate/kiln furnace, in which the 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 °F and higher. This temperature is required to meet taconite pellet product specifications. Direct-fired fuel combustion in the induration furnace is carried out at 300% to 400% excess air to provide sufficient oxygen for pellet oxidation.

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 using hot exhaust gases to heat up incoming pellets. Pellet drying and 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 within process

constraints. The pellet coolers are also used to preheat combustion air so more of the fuel's energy is directed to the process instead of heating ambient air to combustion temperatures.

Tilden has two grate/kiln furnaces, Line 1 and Line 2. Line 1 is subject-to-BART and Line 2 is not subject to BART because Line 2 was installed outside the BART applicability time window. Line 1 is permitted to burn natural gas, coal and fuel oil. Line 1 is controlled by an electrostatic precipitator (ESP). The ESP is designed to remove PM and would be considered a high efficiency PM ESP. Kiln 1 has a PM limit of 0.065 per 1000 pounds of exhaust gas and 200 pounds per hour. NO<sub>x</sub> is controlled through furnace design and type of fuel usage. During high ozone alert days, coal is burned to reduce the amount of NO<sub>x</sub> generation. The SO<sub>2</sub> is controlled through furnace design and type of fuel usage. Kiln 1 has a SO<sub>2</sub> limit of 28,000 lbs per day.

### **5.A.i Sulfur Dioxide Controls**

There are two sources of SO<sub>2</sub> emissions from the Line 1 Indurating Furnace:

1. SO<sub>2</sub> emissions from the trace amounts of sulfur in the iron concentrate and binding agents present in the green balls; and
2. SO<sub>2</sub> emission from the sulfur in distillate fuel oil and coal, which are the permitted fuels.

#### **5.A.i.a STEP 1 – Identify All Available Retrofit Control Technologies**

See Appendix D for a comprehensive list of all potential retrofit control technologies that were evaluated. Many emerging technologies have been identified that are not currently commercially available. A preliminary list of technologies was submitted to MDEQ on October 6, 2006 with the status of the technology as it was understood at that time. Appendix D presents the current status of the general availability of each technology.

#### **5.A.i.b STEP 2 – Eliminate Technically Infeasible Options**

Step 1 identified the available and applicable technologies for SO<sub>2</sub> emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO<sub>2</sub> control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for indurating furnaces.

## **Wet Walled Electrostatic Precipitator (WWESP)**

An ESP 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.

A wet walled electrostatic precipitator (WWESP) operates on the same collection principles as a dry ESP and uses a water spray to remove particulate matter from the collection plates. For SO<sub>2</sub> removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO<sub>2</sub> absorber.

The SO<sub>2</sub> control efficiency for a WWESP is dependent upon various process specific variables, such as SO<sub>2</sub> flue gas concentration, fuel used, and ore composition. Tilden currently employs an ESP designed for removal of particulate matter. The existing ESP does not have the capacity to handle the additional loading of sulfate particulates. To add a WWESP to the process, it would be necessary to install it in series with the existing ESP. A control efficiency of a WWESP ranges from 30-80% dependent upon the process specific operating parameters.

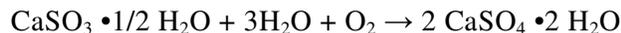
Based on the information contained within this report, a WWESP is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

## **Wet Scrubbing (High and Low Efficiency)**

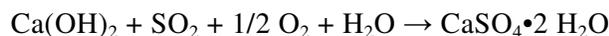
Wet scrubbing, when applied to remove SO<sub>2</sub>, is generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO<sub>2</sub> in the waste gas. Crushed limestone, lime, or caustic are used as scrubbing agents. Most wet scrubbers recirculate the scrubbing solution, which minimizes the wastewater discharge flow. However, higher concentrations of solids exist within the recirculated wastewater.

For a wet scrubber to be considered a high efficiency SO<sub>2</sub> wet scrubber, the scrubber would require designs for removal efficiency up to 95% SO<sub>2</sub>. Typical high efficiency SO<sub>2</sub> wet scrubbers are packed-bed spray towers using a caustic scrubbing solution. Whereas, a low efficiency SO<sub>2</sub> wet scrubber could have a control efficiency of 30% or lower. A low efficiency SO<sub>2</sub> scrubber could be a venturi rod scrubber design using water as a scrubbing solvent. Venturi rod scrubbers, which are frequently used for PM control at taconite facilities, will also remove some of the SO<sub>2</sub> from the flue gas as collateral emission reduction.

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



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:



When caustic (sodium hydroxide solution) is the scrubbing agent, the SO<sub>2</sub> removal reactions are as follows:



Caustic scrubbing produces a liquid waste, and minimal equipment is needed as compared to lime or limestone scrubbers. If lime or limestone is used as the reagent for SO<sub>2</sub> 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<sub>2</sub> control efficiency range for SO<sub>2</sub> scrubbers on coal-fired utility boilers with oxygen concentrations of 2-3% is 80% to 90% for low efficiency scrubbers and 90% to 95% for high efficiency scrubbers. The highest control efficiencies can be achieved when SO<sub>2</sub> concentrations are the highest. The indurating furnace SO<sub>2</sub> concentration would be considered low due to the high air flow rates required to assure product quality. Unlike coal-fired boilers, indurating furnaces operate with maximum excess air to enable proper oxidation of the pellet. The excess air dilutes the SO<sub>2</sub> concentration as well as creates higher flow rates to control. Additionally, the varying sulfur concentration within the pellet causes fluctuations of the SO<sub>2</sub> concentrations in the exhaust gas stream. This could also impact the SO<sub>2</sub> control efficiency of the wet scrubber.

Based on the information contained within this report, a wet scrubber is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection)**

Dry sorbent injection (DSI) of lime/limestone is a post-combustion SO<sub>2</sub> control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO<sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO<sub>2</sub> removal occurs as the flue gas flows through the filter cake on the bags. The normal SO<sub>2</sub> control efficiency range for dry SO<sub>2</sub> scrubbers is 70% to 90 % for coal fired utility boilers. Depending on the residence time and gas stream temperature, DSI control efficiency for an indurating furnace is estimated at 55%.

Based on the information contained within this report, DSI is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Spray Dryer Absorption (SDA)**

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO<sub>2</sub> is absorbed by the slurry, forming CaSO<sub>3</sub>/CaSO<sub>4</sub>. 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<sub>2</sub>, the term flue-gas desulfurization (FGD) may also be used.

Based on the information contain with this report, SDA is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption, which results in lower operating costs. Typically, reduced fuel usage translates into reduced pollution emissions. Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

## **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has moved companies to evaluate alternate fuel sources. These fuel sources come in all physical forms – solid, liquid and gas. To achieve reduction of SO<sub>2</sub> emissions through alternative fuel usage, the source must be capable of burning fuels with lower sulfur content than the existing fuels. Switching fuels trades one visibility impairment pollutant (SO<sub>2</sub>) for another (NO<sub>x</sub>), as induction furnaces emit significantly less NO<sub>x</sub> when burning solid fuels. Therefore, if this option is pursued, the impact on emissions of all visibility pollutants must be quantified and the cumulative visibility impact modeled to determine the net benefit of a particular alternative fuel.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as an option, not to direct the fuel choice.<sup>27</sup>

Therefore, due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and the fact that BART is not intended to mandate a fuel switch, alternative fuels as an SO<sub>2</sub> air pollution control technology will not be further evaluated in this report. However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

## **Coal Processing**

Pre-combustion coal processing techniques have been proposed as one strategy to reduce uncontrolled SO<sub>2</sub> emissions. Coal processing technologies are being developed to remove moisture and potential contaminants from the coal prior to use.

These processes typically employ both mechanical and thermal means to increase the quality of coal by removing moisture, sulfur, mercury, and heavy metals. In one process, raw coal from the mine enters a first stage separator where it is crushed and screened to remove large rock and rock material.<sup>28</sup> The processed coal is then passed on to an intermediate storage facility prior to being sent to the next stage in the process, the thermal process. In this stage, coal passes through pressure locks into the thermal processors where steam is injected. Moisture in the coal is released under these conditions. Mineral inclusions are also fractured under thermal stress, removing both included rock

---

<sup>27</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

<sup>28</sup> The coal processing description provided herein is based on the K-Fuel® process under development by KFx, Inc.

and sulfur-forming pyrites. After treatment, the coal is discharged into a second pressurized lock. The second pressurized lock is vented into a water condenser to return the processor to atmospheric pressure and to flash cool the coal. Water, removed from the process at various points, and condensed process steam are reused within the process or treated prior to being discharged.

To date, the use of processed fuels has only been demonstrated with test burns in a pulverized coal-fired boiler. Using processed fuels at a taconite plant would require research, test burns, and extended trials to identify potential impacts on plant systems, including the furnaces, material handling, and emission control systems. Therefore, processed fuels are not considered commercially available, and will not be analyzed further in this BART analysis.

Coal crushing and drying is currently employed by Tilden as an incidental option for SO<sub>2</sub> reduction. In the process, raw coal is crushed and screened to remove rocks and other impurities. The crushed coal is then thermally processed to remove excess moisture. Coal crushing and drying is already in use, so further reductions from this control option are not possible. Therefore, it will not be further evaluated in this report.

## Step 2 Conclusion

Based upon the determination within Step 2, the remaining SO<sub>2</sub> control technologies that are available and applicable as secondary controls to the existing indurating furnace wet scrubbers are identified in Table 5-1. The technical feasibility as determined in Step 2 is also included in Table 5-1.

**Table 5-1 Indurating Furnace SO<sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility**

<b>SO<sub>2</sub> Pollution Control Technology</b>	<b>Available?</b>	<b>Applicable?</b>	<b>Technically Feasible?</b>
Wet Walled Electrostatic Precipitator (WWESP)	Yes	Yes	Yes
Wet Scrubbing	Yes	Yes	Yes
Dry sorbent injection (DSI)	Yes	Yes	Yes
Spray Dryer Absorption (SDA)	Yes	Yes	Yes
Energy Efficiency Projects	Yes	Yes	Project Dependent
Alternative Fuels	Yes	Yes	Yes – Not Required by BART
Coal Processing	No	No	No

### 5.A.i.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 5-2 describes the expected control efficiency from each of the remaining feasible control options.

**Table 5-2 Indurating Furnace SO<sub>2</sub> Control Technology Effectiveness**

SO <sub>2</sub> Pollution Control Technology	Approximate Control Efficiency
SDA	90%
Wet Scrubber	80%
WWESP	80%
DSI	55%

### 5.A.i.d STEP 4 – Evaluate Impacts and Document the Results

As illustrated in Table 5-2 above, the technically feasible control remaining provide varying levels of emission reduction. Therefore, it is necessary to consider the economic, energy, and environmental impacts to better differentiate as presented below.

#### Economic Impacts

Table 5-3 details the expected costs associated with installation of the above alternatives on each stack. Equipment design was based on the maximum 24-hour emissions, vendor estimates, and U.S. EPA cost models. Capital costs were based on a recent vendor quotation. The cost for that unit was scaled to each stack's flow rate using the six-tenths-factor rule as shown in the following equation:

$$\text{Cost of equipment A} = \text{Cost of equipment B} * (\text{capacity of A/capacity of B})^{0.6}$$

Direct and indirect costs were estimated as a percentage of the fixed capital investment using U.S. EPA models and factors. Operating costs were based on 100% utilization and annual operating hours of 7680 hours. Operating costs of consumable materials, such as electricity, water, and chemicals were established based on the U.S. EPA control cost manual<sup>29</sup> and engineering experience, and were adjusted for the specific flow rates and pollutant concentrations.

Due to space considerations, 60%<sup>30</sup> of the total capital investment was included in the costs to account for a retrofit installation. After a tour of the facility and discussions with facility staff, it was

<sup>29</sup> U.S. EPA, January 2002, *EPA Air Pollution Control Cost Manual, Sixth Edition*.

<sup>30</sup> U.S. EPA, *CUE Cost Workbook Version 1.0*. Page 2.

determined the space surrounding the furnaces is congested, and the area surrounding the building supports vehicle and rail traffic to transport materials to and from the building. Additionally, the structural design of the existing building would not support additional equipment on the roof. Therefore, the cost estimates provide for additional site-work and construction costs to accommodate the new equipment within the facility. A site-specific estimate for site work, foundations, and structural steel was added to arrive at the total retrofit installed cost of the control technology. The site specific estimate was based on Barr's experience with similar retrofit projects. See Appendix C for an aerial photo of the facility. The detailed cost analysis is provided in Appendix A.

**Table 5-3 Indurating Furnace SO<sub>2</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (MM\$)</b>	<b>Total Annual Cost (MM\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>
SDA	\$167,260,397	\$23,254,882	\$22,407
Wet Scrubber	\$34,869,327	\$6,048,540	\$6,557
WWESP	\$52,638,755	\$13,922,184	\$15,091
DSI	\$42,082,032	\$9,975,786	\$15,729

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are

evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>31</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts. Based on the information presented in table 5-3, the wet scrubber is the only technology that requires analysis for visibility improvement, energy and other impacts.

The BART guidance documents also present a calculation method for incremental control cost which is intended to present the incremental value of each technology as compared to the next most effective alternative. Since only one of the technologies is cost effective, the incremental control cost is not applicable and is not presented in this analysis.

### Energy and Environmental Impacts

The energy and non-air quality impacts for wet scrubbers are presented in Table 5-4.

**Table 5-4 SO<sub>2</sub> Control Technology Impacts Assessment**

Control Technology	Energy Impacts	Other Impacts
Wet Scrubber	Significant pressure drop results in higher electrical requirements	<ul style="list-style-type: none"> <li>• Additional water consumption and wastewater generation</li> <li>• Increased facility water balance and water quality issues</li> <li>• Ponding for scrubber discharge will be limited because of site space constraints</li> <li>• Additional solid waste/sludge generation</li> <li>• Process downtime/lost production during installation</li> </ul>

Table 5-4 notes that wet scrubbers would require additional water consumption. Michigan’s Upper Peninsula has experienced a drought in the past several years. Use of wet scrubbers would create additional demand for water, a resource that is already stressed due to the recent drought conditions. Because the cost of the remaining SO<sub>2</sub> control technologies for Tilden Line 1 furnace is so high and

---

<sup>31</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

does not meet a reasonable definition of cost effective technology, these technologies are removed from further consideration in this analysis.

#### **5.A.i.e STEP 5 – Evaluate Visibility Impacts**

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. This section of the report evaluates the visibility impacts of BART SO<sub>2</sub> control for the Line 1 Indurating Furnace and the resulting degree of visibility improvement.

#### **Predicted 24-Hour Maximum Emission Rates**

Consistent with the use of the highest daily emissions for baseline, or pre-BART, visibility impacts, the post-control emissions to be used for the visibility impacts analysis should also reflect a maximum 24-hour average project emission rate. In the visibility impacts analysis for SO<sub>2</sub>, the emissions from the sources undergoing a full BART SO<sub>2</sub> analysis were adjusted to reflect the projected 24-hour maximum SO<sub>2</sub> emission rate when applying the control technologies that met the threshold requirements of steps 1 – 4. The emissions from all other Subject-to-BART sources were not changed. Table 5-5 provides a summary of the modeled 24-hour maximum emission rates and their computational basis for the evaluated SO<sub>2</sub> control technologies. Table 5-6 provides a summary of the modeling input data.

**Table 5-5 Post-Control Modeling Scenarios**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal	Good Combustion Practice	0.0%	200.2	0.0%	800.9
			Natural Gas			72.8		291.1
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
2	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0	0.0%	800.9
						14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
3	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0	80% 80%	160.2
						14.6		58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
6	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0	0.0%	800.9
						14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
7	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0	80% 80%	160.2
						14.6		58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
10	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0	0.0%	800.9
						14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0	80% 80%	160.2
						14.6		58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
14	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0	0.0%	800.9
						14.6		291.1

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
15	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
18	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80%	40.0	0.0%	800.9
					80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
19	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
22	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80%	40.0	0.0%	800.9
					80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
26	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80%	40.0	0.0%	800.9
					80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
27	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
30	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
31	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

**Table 5-6 Post-Control SO<sub>2</sub> Modeling Scenarios - Modeling Input Data**

Control Scenario	SV #	Emission Unit	Stack Latitude	Stack Longitude	Height of Opening from Ground (ft)	Base Elevation of Ground (ft)	Stack length, width, or Diameter (ft)	Flow Rate at exit (acfm)	Exit Temp (°F)
All Scenarios	SVP0051981 SVP0051711	EUKILN1	46.44084994	-87.653 40738	240	1474	19.3	842,000	300
			46.44075383	-87.651 32336	160		13.5	306,000	300
	SVP0082951	EUDRYER1	46.44075383	-87.651 32336	119	1474	6.3	57,135	150
	SVBLR.STK. T1	EUBOILER1 EUBOILER2	46.44091784	-87.654 12418	130	1474	7.5	192,000	350

## **Post-Control Visibility Impacts Modeling Results**

Results of the post-control visibility impacts modeling for SO<sub>2</sub> are presented in Table 5-7. The results summarize the 98th percentile dV value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas. The comparison of the post-control modeling scenarios to the baseline conditions is presented in Table 5-8.

As illustrated in Tables 5-7 and 5-8, the highest facility baseline visibility contribution is 0.72 dV. A wet scrubber (Scenario 2) would potentially reduce the visibility contribution by 0.1 dV at a cost of over \$34 million in installed capital cost and a total annual cost of over \$6.0 million per year. This would result in a cost per deciview reduction of over \$60 million per deciview.

Visibility impacts with NO<sub>x</sub> controls are presented in Section 6.

**Table 5-7 Post-Control SO<sub>2</sub> Modeling Scenarios - Visibility Modeling Results**

Scenario #	Class I Area with Greatest Impact	2002		2003		2004		2002 – 2004 Combined	
		Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98 <sup>th</sup> Percentile Value (deciview)	No. of days exceeding 0.5 deciview
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
2	IRNP	0.610	15.0	0.620	10.000	0.535	8.000	0.600	33
3	IRNP	0.183	0.0	0.177	0.000	0.154	0.000	0.173	0
6	IRNP	0.619	15.0	0.623	10.000	0.528	8.000	0.598	33
7	IRNP	0.182	0.0	0.177	0.000	0.155	0.000	0.169	0
10	IRNP	0.618	15.0	0.607	10.000	0.527	8.000	0.590	33
11	IRNP	0.176	0.0	0.168	0.000	0.150	0.000	0.161	0
14	IRNP	0.627	15.0	0.608	9.000	0.544	8.000	0.585	32
15	IRNP	0.176	0.0	0.171	0.000	0.150	0.000	0.160	0
18	IRNP	0.626	15.0	0.605	9.000	0.542	8.000	0.596	32
19	IRNP	0.175	0.0	0.173	0.000	0.151	0.000	0.163	0
22	IRNP	0.625	15.0	0.602	9.000	0.291	3.000	0.588	27
23	IRNP	0.175	0.0	0.170	0.000	0.150	0.000	0.165	0
26	IRNP	0.623	15.0	0.605	9.000	0.550	8.000	0.597	32
27	IRNP	0.176	0.0	0.172	0.000	0.151	0.000	0.165	0
30	IRNP	0.613	14.0	0.614	9.000	0.542	8.000	0.588	31
31	IRNP	0.173	0.0	0.172	0.000	0.151	0.000	0.164	0

**Table 5-8 Post-Control SO<sub>2</sub> Modeling Scenarios - Visibility Improvements**

Scenario	Modeling Results								
	0	2002		2003		2004		2002-2004	
	Limiting Class I Area	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
2	IRNP	0.104	4	0.102	1	0.064	3	0.074	8
3	IRNP	0.531	19	0.545	11	0.445	11	0.501	41
6	IRNP	0.095	4	0.099	1	0.071	3	0.076	8
7	IRNP	0.532	19	0.545	11	0.444	11	0.505	41
10	IRNP	0.096	4	0.115	1	0.072	3	0.084	8
11	IRNP	0.538	19	0.554	11	0.449	11	0.513	41
14	IRNP	0.087	4	0.114	2	0.055	3	0.089	9
15	IRNP	0.538	19	0.551	11	0.449	11	0.514	41
18	IRNP	0.088	4	0.117	2	0.057	3	0.078	9
19	IRNP	0.539	19	0.549	11	0.448	11	0.511	41
22	IRNP	0.089	4	0.12	2	0.308	8	0.086	14
23	IRNP	0.539	19	0.552	11	0.449	11	0.509	41
26	IRNP	0.091	4	0.117	2	0.049	3	0.077	9
27	IRNP	0.538	19	0.55	11	0.448	11	0.509	41
30	IRNP	0.101	5	0.108	2	0.057	3	0.086	10
31	IRNP	0.541	19	0.55	11	0.448	11	0.51	41

## 5.A.ii Nitrogen Oxide Controls

To be able to control NO<sub>x</sub> it is important to understand how NO<sub>x</sub> is formed. There are three mechanisms by which NO<sub>x</sub> production occurs: thermal, fuel and prompt NO<sub>x</sub>.

- Fuel bound NO<sub>x</sub> is formed from fuel combustion as nitrogen compounds in the fuel are oxidized.
- Thermal NO<sub>x</sub> production arises from the thermal dissociation of nitrogen and oxygen molecules within the furnace. Combustion air is the primary source of nitrogen and oxygen. In taconite furnaces, thermal NO<sub>x</sub> production is a function of the residence time, free oxygen, and temperature, primarily in the flame area of the furnace.
- Prompt NO<sub>x</sub> is a form of thermal NO<sub>x</sub> which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NO<sub>x</sub> are emitted as prompt NO<sub>x</sub>.

The majority of NO<sub>x</sub> is emitted as NO. Minor amounts of NO<sub>2</sub> are formed in the furnaces.

### 5.A.ii.a STEP 1 – Identify All Available Retrofit Control Technologies

With the understanding of how NO<sub>x</sub> is formed, available and applicable control technologies were evaluated. See Appendix D for a comprehensive list of all potential retrofit control technologies that were evaluated.

### 5.A.ii.b STEP 2 – Eliminate Technically Infeasible Options

Step 1 identified the available and applicable technologies for NO<sub>x</sub> emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit NO<sub>x</sub> control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for indurating furnaces.

#### External Flue Gas Recirculation (EFGR)

External flue gas recirculation (EFGR) uses flue gas as an inert material to reduce flame temperatures thereby reducing thermal NO<sub>x</sub> formation. 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 NO<sub>x</sub> emissions. For this technology to be effective, the combustion conditions must have the ability to be controlled at the burner tip.

The normal NO<sub>x</sub> control efficiency range for EFGR is 30% to 50%.

Application of EFGR technology in taconite induration is problematic for three reasons:

1. The exhaust gas in an induration furnace typically has an oxygen content that is close to ambient, or 18% oxygen, vs. a boiler which has 2% - 3% oxygen. In a boiler, the flue gas is relatively inert and oxygen starved so it can be used as a diluent for flame temperature reduction. Taconite waste gas has much higher oxygen level; thus use of taconite waste gas for EFGR would be equivalent to adding combustion air instead of an inert gas.
2. The oxidation zone of induration furnaces needs to be above 2,400°F in order to meet product specifications. Existing burners are designed to meet these process conditions. Application of EFGR would reduce flame temperatures. Lower flame temperatures would reduce furnace temperatures to the point that product quality could be jeopardized.
3. Application of EFGR technology increases flame length. Dilution of the combustion reactants increases the reaction time needed for fuel oxidation to occur; so, flame length increases. Therefore, application of EFGR could result in flame impingement on furnace components. That would subject those components to excessive temperatures and cause equipment failures.

Although this may be an available and applicable control option, it is not technically feasible due to the high oxygen content of the flue gas and will not be further evaluated in this report.

### **Low-NO<sub>x</sub> Burners**

Low-NO<sub>x</sub> burner (LNB) technology utilizes advanced burner design to reduce NO<sub>x</sub> formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is typically a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion.

In the primary combustion zone of a staged fuel burner, NO<sub>x</sub> formation is limited by a rich (high fuel) condition. Oxygen levels and flame temperatures are low; this results in less NO<sub>x</sub> 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  $NO_x$  control efficiency for LNB in high temperature applications is 10%. Low  $NO_x$  burners have been installed in the preheating section of a straight-grate furnace at another taconite plant; however, the Line 1 Indurating Furnace does not contain a pre-heat burner section. If LNB were to be applied in the indurating zone of the furnace, the reduced flame temperatures associated with LNB would adversely affect taconite pellet product quality. LNB has not been applied to the indurating or preheat zones of any grate-kiln taconite furnace. Therefore, this option is not technically feasible.

It is also important to note that there are other methods being developed for LNB which are not yet commercially available. Some incorporate various fuel dilution techniques to reduce flame temperatures; such as mixing an inert gas like  $CO_2$  with natural gas. Water injection to cool the burner peak flame temperature is also being investigated. This technique has already been successfully used for reducing  $NO_x$  emissions from gas turbines and a straight-grate taconite indurating furnace in the Netherlands. The water injection technique shows promise for high temperature applications, but will not be further investigated in this report as the technology is still in the development phase and is not yet commercially available.

### **Induced Flue Gas Recirculation Burners**

Induced flue gas recirculation burners, also called ultra low- $NO_x$  burners, combine the benefits of flue gas recirculation and low- $NO_x$  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  $NO_x$  control efficiency for IFGR burners in high temperature applications is 25-50%.

As noted above, taconite furnaces are designed to operate with oxygen levels near 18%. At these oxygen levels, flue gas recirculation is ineffective at  $NO_x$  reduction, and it would adversely affect combustion because excessive amounts of oxygen would be injected into the flame pattern. In addition, IFGR relies on convective flow of flue gas through the burner and requires burners to be up-fired; meaning that the burner is mounted in the furnace floor and the flame rises up. Furthermore, IFGR is not feasible because the reduced flame temperatures associated with IFGR would adversely affect taconite pellet product quality.

Although this may be an available and applicable control option, it is not technically feasible due to the high oxygen content of the flue gas and will not be further evaluated in this report.

## **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption, which results in lower operating costs. Typically, reduced fuel usage translates into reduced pollution emissions. Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization for this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

## **Ported Kilns**

Ported kilns are rotary kilns that have air ports installed at specified points along the length of the kiln for process improvement. 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 produces 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 reduces the carry over of the oxidation reaction into the pellet coolers.

Ported kilns are potentially applicable to grate-kilns. In the past, the technology was believed to reduce NO<sub>x</sub> formation. However, the technology vendor will not guarantee that ported kilns will reduce NO<sub>x</sub> emissions because controlling the oxygen in the firing zone is not possible due to the flow of air from the pellet cooler<sup>32</sup>. Any reduction in NO<sub>x</sub> would be minor and incidental to the process improvement and specific to the individual furnace. Therefore, although this may be an available and applicable technology, its NO<sub>x</sub> reduction potential is small and may be unsuccessful because of the design of the pellet cooler area. Ported kilns will not be further evaluated in this report.

## **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has moved companies to evaluate alternate fuel sources. These fuel sources come in all physical forms – solid, liquid and

---

<sup>32</sup> Telephone conversation with Metso, July 18, 2006.

gas. Reduction of NO<sub>x</sub> emissions through alternative fuel usage has been achieved at taconite grate-kilns through the use of solid fuel. In these cases the reduction resulted due to changes from pulverized solid fuel dispersal in the kiln that resulted in lower flame temperature compared to other fuels. Switching from natural gas or oil to solid fuel has a potential drawback in that it can exchange one visibility impairment pollutant (NO<sub>x</sub>) for another (SO<sub>2</sub>). Therefore, if this option is pursued, the impact on emissions of all visibility pollutants must be quantified and the cumulative visibility impact modeled to determine the net benefit of a particular alternative fuel.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as an option, not to direct the fuel choice.<sup>33</sup>

However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

## **Coal Processing**

Pre-combustion coal processing techniques have been proposed as one strategy to reduce uncontrolled NO<sub>x</sub> emissions. Coal processing technologies are being developed to remove moisture and potential contaminants from the coal prior to use.

These processes typically employ both mechanical and thermal means to increase the quality of coal by removing moisture, sulfur, mercury, and heavy metals. In one process, raw coal from the mine enters a first stage separator where it is crushed and screened to remove large rock and rock material.<sup>34</sup> The processed coal is then passed on to an intermediate storage facility prior to being sent to the next stage in the process, the thermal process. In this stage, coal passes through pressure locks into the thermal processors where steam is injected. Moisture in the coal is released under these conditions. Mineral inclusions are also fractured under thermal stress, removing both included rock and sulfur-forming pyrites. After treatment, the coal is discharged into a second pressurized lock. The second pressurized lock is vented into a water condenser to return the processor to atmospheric pressure and to flash cool the coal. Water, removed from the process at various points, and condensed process steam are reused within the process or treated prior to being discharged.

---

<sup>33</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

<sup>34</sup> The coal processing description provided herein is based on the K-Fuel<sup>®</sup> process under development by KFx, Inc.

To date, the use of processed fuels has only been demonstrated with test burns in a pulverized coal-fired boiler. Using processed fuels at a taconite plant would require research, test burns, and extended trials to identify potential impacts on plant systems, including the furnaces, material handling, and emission control systems. Therefore, processed fuels are not considered commercially available, and will not be analyzed further in this BART analysis.

Coal crushing and drying is currently employed by Tilden as an incidental option for NO<sub>x</sub> reduction. In the process, raw coal is crushed and screened to remove rocks and other impurities. The crushed coal is then thermally processed to remove excess moisture. Coal crushing and drying is already in use, so further reductions from this control option are not possible. Therefore, it will not be further evaluated in this report.

### **Process Optimization with Parametric Monitoring**

There are several concerns with utilizing process optimization as an available, applicable and technically feasible control option for the taconite industry:

- Typical taconite furnaces are designed and operated to convert magnetite to hematite in the presence of excess oxygen and require heat input to initiate the reaction which is exothermic and releases heat once initiated. Fuel combustion is only part of the process and therefore this process is different from a boiler.
- The quality of the process feed materials to the furnace is variable at some taconite operations and product quality may be compromised by attempting to fine tune heat input to minimize NO<sub>x</sub> formation.
- At some operations, the operating parameters which generally influence the rate of NO<sub>x</sub> generation such as flame temperature, fuel usage and excess air are relatively constant during operation of the furnace, independent of process operation variability. This indicates that NO<sub>x</sub> formation may not be dependent upon controllable operating parameters. In the absence of controllable parameters, process optimization would not be effective at controlling NO<sub>x</sub> emissions.

Based upon this information, there is no indication that further emission reductions would be achieved through process optimization using parametric monitoring as a control technology. Therefore, process optimization as a control option will not be evaluated further in this report.

## Post Combustion Controls

NO<sub>x</sub> can be controlled using add-on systems located downstream of the combustion process. The two main techniques in commercial service include the selective non catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NO<sub>x</sub> downstream of the combustion chamber. Examples of these alternatives are nonselective catalytic reduction (NSCR) and Low Temperature Oxidation (LTO). Each of these alternatives is described below.

### Non-Selective Catalytic Reduction (NSCR)

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR catalyst is very sensitive to poisoning; so, NSCR is usually applied primarily in natural gas combustion applications.

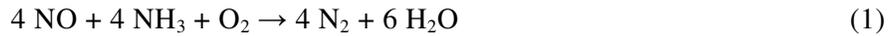
NSCR is often referred to as “three-way conversion” catalyst because it simultaneously reduces NO<sub>x</sub>, unburned hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO<sub>x</sub> emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under this condition, in the presence of a catalyst, NO<sub>x</sub> is reduced by CO, resulting in nitrogen (N<sub>2</sub>) and carbon dioxide (CO<sub>2</sub>). The most important reactions for NO<sub>x</sub> removal are:



NSCR catalyst has been applied primarily in clean combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, making it infeasible to apply this technology to the indurating furnace. In addition, we are not aware of any NSCR installations on taconite induration furnaces or similar combustion equipment. Therefore, this technology is not considered to be available and applicable, and therefore will not be further evaluated in this report.

## Selective Catalytic Reduction (SCR) and Regenerative Selective Catalytic Reduction (R-SCR)

SCR is a post-combustion NO<sub>x</sub> control technology in which ammonia (NH<sub>3</sub>) is injected into the flue gas stream in the presence of a catalyst. NO<sub>x</sub> is removed through the following chemical reaction:



A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO<sub>x</sub> decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670°F, the oxidation of ammonia begins to become significant. At low temperatures, the formation of ammonium bisulfate causes scaling and corrosion problems.

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.

Ammonia slip from the SCR system is usually less than 3 to 5 ppm. The emission of ammonia increases during load changes due to the instability of the temperature in the catalyst bed as well as at low loads because of the low gas temperature.

Regenerative Selective Catalytic Reduction (R-SCR) applies the Selective Catalytic Reduction (SCR) control process as described above with a preheat process step to reheat the flue gas stream up to SCR catalyst operating temperatures. The preheating process combines use of a thermal heat sink (packed bed) and a duct burner. The thermal sink recovers heat from the hot gas leaving the R-SCR and then transfers that heat to gas entering the R-SCR. The duct burner is used to complete the preheating process. R-SCR operates with several packed bed/SCR reactor vessels. Gas flow alternates between vessels. Each of the vessels alternates between preheating/treating and heat recovery.

The benefits of R-SCR are:

- Its high energy efficiency allows it to be used after SO<sub>2</sub> and particulate controls.
- R-SCR has a thermal efficiency of 70% vs. standard heat exchangers which have a thermal efficiency of 60% to 70%.

- Application of R-SCR after SO<sub>2</sub> and PM controls significantly reduces the potential for problems associated with plugging and catalyst poisoning and deactivation.

There are several concerns about the technical feasibility and applicability of R-SCR on an indurating furnace:

- The composition of the indurating furnace flue gas is significantly different from the composition of the flue gas from the boilers that utilize R-SCR;
- The taconite dust is highly erosive and can cause significant equipment damage. R-SCR has a number of valves which must be opened and closed frequently to switch catalyst/heat recovery beds. These valves could be subject to excessive wear in a taconite application due to the erosive nature of the taconite dust;
- R-SCR has not been applied downstream of a wet scrubber. Treating a stream saturated with water may present design problems in equipment sizing for proper heat transfer and in corrosion protection;
- R-SCR catalyst has been shown to oxidize mercury. Oxidized mercury can be absorbed by the local environment and have an adverse impact. The impact of RSCR on mercury emissions needs to be studied to determine whether or not mercury oxidation is a problem and to identify mitigation methods if needed.

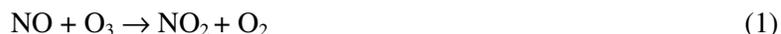
To date, R-SCR has been applied to wood-fired utility boilers. Application of this technology has not been applied to taconite induration furnaces, to airflows of the magnitude of taconite furnace exhausts, nor to exhaust streams with similar, high moisture content. Using R-SCR at a taconite plant would require research, test runs, and extended trials to identify potential issues related to catalyst selection, and impacts on plant systems, including the furnaces and emission control systems. It is not reasonable to assume that vendor guarantees of performance would be forthcoming in advance of a demonstration project. The timeline required to perform such a demonstration project would likely be two years to develop and agree on the test plan, obtain permits for the trial, commission the equipment for the test runs, perform the test runs for a reasonable study period, and evaluate and report on the results. The results would not be available within the time window for establishing emission limits to be incorporated in the state implementation plan (SIP) by December 2007.

Recalling U.S. EPA’s intention regarding “available” technologies to be considered for BART, as mentioned in Section 2.B, facility owners are not expected to undergo extended trials in order to learn how to apply a control technology to a completely new and significantly different source type. Therefore, R-SCR is not considered to be technically feasible, and will not be analyzed further in this BART analysis.

SCR with reheat through a conventional duct burner (rather than using a regenerative heater) has been successfully implemented more widely and in higher airflow applications and will be carried forward in this analysis as available and applicable technology that is reasonably expected to be technically feasible.

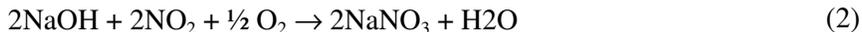
### Low Temperature Oxidation (LTO)

The LTO system utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO<sub>x</sub>. In the system, the NO<sub>x</sub> in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution forming sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system. Commercially available LTO systems include Tri-NO<sub>x</sub>® and LoTOx®.



### Low Temperature Oxidation (Tri-NO<sub>x</sub>®)

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO<sub>2</sub> in a primary scrubbing stage. Then NO<sub>2</sub> is removed through caustic scrubbing in a secondary stage. The reactions are as follows:



Tri-NO<sub>x</sub><sup>®</sup> is a multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO<sub>2</sub>. Subsequent stages reduce NO<sub>2</sub> to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-NO<sub>x</sub><sup>®</sup> is typically applied at small to medium sized sources with high NO<sub>x</sub> concentration in the exhaust gas (1,000 ppm NO<sub>x</sub>). NO<sub>x</sub> concentrations in the exhaust at Tilden are typically less than 200 ppm. Therefore, Tri-NO<sub>x</sub><sup>®</sup> is not applicable to taconite processing and will not be analyzed further in this BART analysis.

### **Low Temperature Oxidation (LoTOx<sup>®</sup>)**

BOC Gases' Lo-TOx<sup>®</sup> is an example of a version of an LTO system. LoTOx<sup>®</sup> technology uses ozone to oxidize NO to NO<sub>2</sub> and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal. The N<sub>2</sub>O<sub>5</sub> is converted to HNO<sub>3</sub> in a scrubber, and is removed with lime or caustic. Ozone for LoTOx<sup>®</sup> is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO<sub>x</sub> control. Ozone is generated from pure oxygen. In order for LoTOx<sup>®</sup> to be economically feasible, a source of low cost oxygen must be available from a pipeline or on-site generation.

The first component of the technical feasibility review includes determining if the technology would apply to the process being reviewed. This would include a review and comparison of the chemical and physical properties required. Although it appears that the chemistry involved in the LTO technology may apply to an indurating furnace, the furnace exhaust contains other ore components that may participate in side reactions. This technology has not been demonstrated on a taconite pellet indurating furnace or any process beyond coal or gas fired boilers. This raises uncertainties about how or whether the technology will transfer to a different type of process.

The second component of the technical feasibility review includes determining if the technology is commercially available. Evaluations of LTO found that it has only been applied to small to medium sized coal or gas fired boiler applications, and has never been demonstrated on a large-scale facility. For example, the current installations of LoTOx<sup>®</sup> are on sources with flue gas flow rates from 150 – 35,000 acfm, which is quite small, compared to the indurating furnace flue gas flow rates of over one million acfm. Therefore, the application of LTO would be more than two orders of magnitude larger

than the biggest current installation. This large scale-up is contrary to good engineering practices and could be problematic in maintaining the current removal efficiencies.

In addition, only two of BOC's LoTOx<sup>®</sup> installations are fully installed and operational applications. Therefore, although this is an emerging technology, the limited application means that it has not been demonstrated to be an effective technology in widespread application.

There are several other concerns about the technical feasibility and applicability of LTO on an indurating furnace:

- The composition of the indurating furnace flue gas is significantly different from the composition of the flue gas from the boilers and process heaters that utilize LTO;
- The taconite dust in the flue gas is primarily magnetite ( $\text{Fe}_3\text{O}_4$ ) which would react with the ozone to form hematite ( $\text{Fe}_2\text{O}_3$ ); since the ozone injection point would be before the scrubber, there can be more than 185 pounds per hour of taconite dust in the flue gas which could consume a significant amount of the ozone being generated which may change the reaction kinetics; consequently, this would necessitate either an increase in the amount of ozone generated or a decrease in the estimated control efficiency;
- The ozone that would be injected into the flue gas would react with the  $\text{SO}_2$ , converting the material to  $\text{SO}_3$  which could result in the generation of sulfuric acid mist from the scrubber;
- Since LTO has not been installed at a taconite plant, it is likely that the application of LTO to an indurating furnace waste gas could present technical problems which were not encountered, or even considered, in the existing LTO applications;
- An LTO system at a taconite facility would also be a source of nitrate discharge to the tailings basin which would change the facility water chemistry which could cause operational problems and would likely cause additional problems with National Pollutant Discharge Elimination System (NPDES) discharge limits and requirements.

Application of this technology has not been tried on taconite induration furnaces, on airflows of the magnitude of taconite furnace exhausts, nor on exhaust streams with similar, high moisture content. Using LTO at a taconite plant would require research, test runs, and extended trials to identify potential issues related to design for high airflows and impacts on plant systems, including the furnaces and emission control systems. It is not reasonable to assume that vendor guarantees of

performance would be forthcoming in advance of a demonstration project. The timeline required to perform such a demonstration project would likely be two years to develop and agree on the test plan, obtain permits for the trial, commission the equipment for the test runs, perform the test runs for a reasonable study period, and evaluate and report on the results. The results would not be available within the time window for establishing emission limits to be incorporated in the state implementation plan (SIP) by December 2007.

Recalling U.S. EPA’s intention regarding “available” technologies to be considered for BART, as mentioned in Section 2.B, facility owners are not expected to undergo extended trials in order to learn how to apply a control technology to a completely new and significantly different source type. Consequently, LTO is technically infeasible on an indurating furnace and will not be evaluated further.

## Step 2 Conclusion

Based upon the determination within Step 2, the remaining NO<sub>x</sub> control technologies that are available and applicable to the indurating furnace process are identified in Table 5-9. The technical feasibility as determined in Step 2 is also included in Table 5-9.

**Table 5-9 Indurating Furnace NO<sub>x</sub> Control Technology – Availability, Applicability, and Technical Feasibility**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Available?</b>	<b>Applicable?</b>	<b>Technically Feasible?</b>
External Flue Gas Recirculation (EFGR)	Yes	No	No
Low NO <sub>x</sub> Burners (LNB)	Yes	Yes	No
Induced Flue Gas Recirculation Burners (IFGR)	Yes	Yes	No
Energy Efficiency Projects	Yes	Yes	Project Dependent
Ported Kilns (Applies to Grate-Kilns Only)	Yes	Yes	No
Alternative Fuels	Yes	Yes	Yes - Not Required by BART
Process Optimization	Yes	No	No
Non-Selective Catalytic Reduction (NSCR)	Yes	No	No

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Available?</b>	<b>Applicable?</b>	<b>Technically Feasible?</b>
Selective Catalytic Reduction (SCR) with conventional reheat	Yes	Yes	Yes
Regenerative SCR	Yes	No	No
Selective Non-Catalytic Reduction (SNCR)	Yes	No	No
Low Temperature Oxidation (LTO)	Yes	No	No

**5.A.ii.cSTEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies**

Table 5-10 describes the expected control efficiency from each of the remaining technically feasible control options as identified in Step 2.

**Table 5-10 Indurating Furnace NO<sub>x</sub> Control Technology Effectiveness**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Approximate Control Efficiency</b>
SCR With conventional reheat	80%

**5.A.ii.d STEP 4 – Evaluate Impacts and Document the Results**

Table 5-11 summarizes the expected costs associated with installation of low NO<sub>x</sub> burners and SCR with conventional reheat. Capital costs were calculated based on the maximum 24-hour emissions, U.S. EPA cost models, and vendor estimates. Vendor estimates for capital costs based on a specific flow rate were scaled to each stack’s flow rate using the six-tenths-factor rule to account for the economy of scale. Operating costs were based on 93% utilization and annual operating hours of 7680 hours for Line 1. Operating costs were proportionally adjusted to reflect site specific flow rates and pollutant concentrations.

After a tour of the facility and discussions with facility staff, it was determined the space surrounding the furnaces is congested and the area surrounding the building supports vehicle and rail traffic to transport materials to and from the building. A site-specific estimate for site-work, foundations, and structural steel was added based upon the facility site to arrive at the total retrofit installed cost of the control technology. The site specific estimate was based on Barr’s experience with recent actual retrofit costs. See Appendix C for a site plan of the facility. Additionally, the structural design of the

existing building would not support additional equipment on the roof. The detailed cost analysis is provided in Appendix A.

**Table 5-11 Indurating Furnace NO<sub>x</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (MM\$)</b>	<b>Total Annual Cost (MM\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>
<b>SCR With conventional reheat</b>	\$65,492,092	\$31,055,581	\$8,416

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>35</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts. Based on the information presented in table 5-11, SCR with conventional reheat is the only technology that requires analysis for visibility improvement, energy and other impacts.

---

<sup>35</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

The BART guidance documents also present a calculation method for incremental control cost which is intended to present the incremental value of each technology as compared to the next most effective alternative. Since only one of the technologies is cost effective, the incremental control cost is not applicable and is not presented in this analysis.

The incremental control cost column in Table 5-11 is intended to present the incremental value of each technology as compared to the technology with the next most effective alternative. Since none of the NO<sub>x</sub> reduction technologies are cost effective, the incremental cost is not applicable.

### Energy and Environmental Impact

The energy and non-air quality impacts for the remaining alternatives are presented in Table 5-12.

**Table 5-12 NO<sub>x</sub> Control Technology Impacts Assessment**

Control Technology	Energy Impacts	Other Impacts
SCR with Reheat	Reheat would require additional natural gas use.	<ul style="list-style-type: none"> <li>• Ammonia slip, which contributes to regional haze. Ammonia reacts with NO<sub>x</sub> to form ammonium nitrate and SO<sub>2</sub> to form ammonium sulfate particles. Ammonium sulfate is hygroscopic and bonds with water in the air to grow large particles. The large particles formed by ammonium sulfate disproportionately contribute to visibility impairment.</li> <li>• Ammonia emissions will increase condensable PM emissions that will have possible PSD permitting implications.</li> <li>• Ammonia deposition onto nearby lakes and waters of the state and contribute nutrients and undesirable biological growth.</li> <li>• Additional safety and regulatory concerns associated with ammonia storage on site.</li> <li>• Possible oxidation of elemental mercury.</li> </ul>

### **5.A.ii.eSTEP 5 – Evaluate Visibility Impacts**

As previously stated in Section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. This section of the report evaluates the visibility impacts of BART NO<sub>x</sub> control and the resulting degree of visibility improvement.

#### **Predicted 24-Hour Maximum Emission Rates**

Consistent with the use of the highest daily emissions for baseline, or pre-BART, visibility impacts, the post-control emissions to be used for the visibility impacts analysis should also reflect a maximum 24-hour average project emission rate. In the visibility impacts analysis for NO<sub>x</sub>, the emissions from the sources undergoing a full BART NO<sub>x</sub> analysis were adjusted to reflect the projected 24-hour maximum NO<sub>x</sub> emission rate when applying the control technologies that met the threshold requirements of steps 1 – 4. The emissions from all other Subject-to-BART sources were not changed. Table 5-13 provides a summary of the modeled 24-hour maximum emission rates and their computational basis for the evaluated NO<sub>x</sub> control technologies. Table 5-14 provides a summary of the modeling input data.

**Table 5-13 Post-Control NO<sub>x</sub> Modeling Scenarios**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal	Good Combustion Practice	0.0%	200.2	0.0%	800.9
			Natural Gas			72.8		291.1
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	8.3	0.0%	3.7
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	0.1	0.0%	19.3
1	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal	SCR w/reheat	0.0%	200.2	80%	160.2
			Natural Gas			72.8	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	0.1	0.0%	19.3
3	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	0.1	0.0%	19.3
5	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	0.1	0.0%	19.3
7	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	0.1	0.0%	19.3
9	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal	SCR w/reheat	0.0%	200.2	80%	160.2
			Natural Gas			72.8	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil	LNB w/FGR	0.0%	0.1	75.0%	4.8
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
					80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	Good Combustion Practice	0.0%	8.3	0.0%	3.7

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
13	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
15	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
17	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
19	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
21	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
25	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
27	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0051711				80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
29	SVP0051981	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2	80%	160.2
	SVP0051711				72.8	80%	58.2	
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
31	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
	SVP0051711				80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

**Table 5-14 Post-Control NO<sub>x</sub> Modeling Scenarios - Modeling Input Data**

Control Scenario	SV #	Emission Unit	Stack Easting (utm)	Stack Northing (utm)	Height of Opening from Ground (ft)	Base Elevation of Ground (ft)	Stack length, width, or Diameter (ft)	Flow Rate at exit (acfm)	Exit Temp (°F)
All Scenarios	SVP0051981 SVP0051711	EUKILN1	46.44084994	-87.653 40738	240	1474	19.3	842,000	300
			46.44075383	-87.651 32336	160		13.5	306,000	300
	SVP0082951	EUDRYER1	46.44075383	-87.651 32336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.654 12418	130	1474	7.5	192,000	350

## Post-Control Visibility Impacts Modeling Results

Results of the post-control visibility impacts modeling for NO<sub>x</sub> are presented in Table 5-15. The results summarize 98th percentile dV value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas. The comparison of the post-control modeling scenarios to the baseline conditions is presented in Table 5-16.

As illustrated in tables 5-15 and 5-16, the facility baseline visibility contribution is 0.72 dV. Installing SCR with conventional reheat on Line 1 when natural gas is burned could potentially reduce the visibility contribution by 0.45 from Scenario 1..

Visibility impacts with SO<sub>2</sub> controls are presented in section 6.

**Table 5-15 Post-Control NO<sub>x</sub> Modeling Scenarios - Visibility Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
1	IRNP	0.323	2.0	0.275	1.000	0.228	1.000	0.248	2
3	IRNP	0.183	0.0	0.177	0.000	0.154	0.000	0.173	0
5	IRNP	0.322	2.0	0.256	0.000	0.219	1.000	0.254	2
7	IRNP	0.182	0.0	0.177	0.000	0.155	0.000	0.169	0
9	IRNP	0.314	2.0	0.252	0.000	0.213	1.000	0.248	2
11	IRNP	0.176	0.0	0.168	0.000	0.150	0.000	0.161	0
13	IRNP	0.315	2.0	0.246	0.000	0.218	1.000	0.243	2
15	IRNP	0.176	0.0	0.171	0.000	0.150	0.000	0.160	0
17	IRNP	0.326	2.0	0.243	0.000	0.218	1.000	0.243	2
19	IRNP	0.175	0.0	0.173	0.000	0.151	0.000	0.163	0
21	IRNP	0.324	2.0	0.241	0.000	0.215	1.000	0.241	2
23	IRNP	0.175	0.0	0.170	0.000	0.150	0.000	0.165	0
25	IRNP	0.326	2.0	0.245	0.000	0.207	1.000	0.241	2
27	IRNP	0.176	0.0	0.172	0.000	0.151	0.000	0.165	0
29	IRNP	0.325	2.0	0.239	0.000	0.198	1.000	0.240	2
31	IRNP	0.173	0.0	0.172	0.000	0.151	0.000	0.164	0

**Table 5-16 Post-Control NO<sub>x</sub> Modeling Scenarios - Visibility Improvements**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV
1	IRNP	0.391	17	0.447	10	0.371	10	0.426	39
3	IRNP	0.531	19	0.545	11	0.445	11	0.501	41
5	IRNP	0.392	17	0.466	11	0.38	10	0.42	39
7	IRNP	0.532	19	0.545	11	0.444	11	0.505	41
9	IRNP	0.4	17	0.47	11	0.386	10	0.426	39
11	IRNP	0.538	19	0.554	11	0.449	11	0.513	41
13	IRNP	0.399	17	0.476	11	0.381	10	0.431	39
15	IRNP	0.538	19	0.551	11	0.449	11	0.514	41
17	IRNP	0.388	17	0.479	11	0.381	10	0.431	39
19	IRNP	0.539	19	0.549	11	0.448	11	0.511	41
21	IRNP	0.39	17	0.481	11	0.384	10	0.433	39
23	IRNP	0.539	19	0.552	11	0.449	11	0.509	41
25	IRNP	0.388	17	0.477	11	0.392	10	0.433	39
27	IRNP	0.538	19	0.55	11	0.448	11	0.509	41
29	IRNP	0.389	17	0.483	11	0.401	10	0.434	39
31	IRNP	0.541	19	0.55	11	0.448	11	0.51	41

## **5.B Process Boilers 1 and 2**

Two natural gas and fuel oil fired process boilers require BART analysis. These boilers provide steam required to operate the taconite plant, as needed. The boilers are only permitted to burn natural gas and used oil.

### **5.B.i Sulfur Dioxide Controls**

Sulfur in the fuel is the only source of SO<sub>2</sub> emissions from these boilers. The boilers have low emissions of SO<sub>2</sub> due to the low sulfur content of the permitted fuels.

#### **5.B.i.a STEP 1 – Identify All Available Retrofit Control Technologies**

See Appendix F for a comprehensive list of all potential retrofit control technologies that were evaluated. Many emerging technologies have been identified that are not currently commercially available. A preliminary list of technologies was submitted to MDEQ on October 6, 2006 with the status of the technology as it was understood at that time. As work on this evaluation progressed, new information became apparent of the limited scope and scale of some of the technology applications. Appendix F presents the current status of the general availability of each technology.

#### **5.B.i.b STEP 2 – Eliminate Technically Infeasible Options**

Step 1 identified the available and applicable technologies for SO<sub>2</sub> emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO<sub>2</sub> control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for indurating furnaces.

#### **Wet Walled Electrostatic Precipitator (WWESP)**

An electrostatic precipitator (ESP) 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.

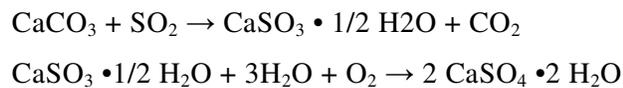
A wet walled electrostatic precipitator (WWESP) operates on the same collection principles as a dry ESP and uses a water spray to remove particulate matter from the collection plates. For SO<sub>2</sub> removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO<sub>2</sub> absorber.

The SO<sub>2</sub> control efficiency for a WWESP is dependent upon various process specific variables, such as SO<sub>2</sub> flue gas concentration and fuel used. Based on the information contained within this report, a WWESP is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

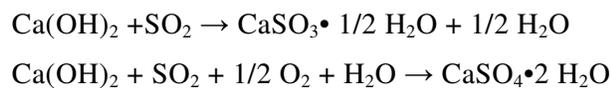
### **Wet Scrubbing (High and Low Efficiency)**

Wet scrubbing, when applied to remove SO<sub>2</sub>, is generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO<sub>2</sub> in the waste gas. Crushed limestone, lime or Caustic is used as scrubbing agents.

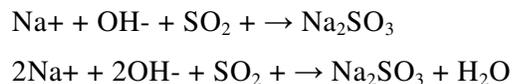
Limestone scrubbing introduces limestone slurry with the flue gas in a spray tower. The sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:



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:



When that caustic (sodium hydroxide solution) is the scrubbing agent, the SO<sub>2</sub> removal reactions are as follows:



Caustic scrubbing produces a liquid waste, and minimal equipment is needed as compared to lime or limestone scrubbers. If lime or limestone is used as the reagent for SO<sub>2</sub> 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<sub>2</sub> control efficiency range for SO<sub>2</sub> scrubbers on coal fired utility boilers is 80% to 90% for low efficiency scrubbers and 90% and more for high efficiency scrubbers. The highest control efficiencies can be achieved when SO<sub>2</sub> concentrations are the highest. The process boiler's exhaust would not have a high SO<sub>2</sub> concentration, so the low end of the efficiency range would be expected.

Based on the information contained within this report, a wet scrubber is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection)**

Dry sorbent injection (DSI) of lime/limestone is a post-combustion SO<sub>2</sub> control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO<sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO<sub>2</sub> removal occurs as the flue gas flows through the filter cake on the bags. The normal SO<sub>2</sub> control efficiency range for dry SO<sub>2</sub> scrubbers is 70% to 90 % for coal fired utility boilers.

Based on the information contained within this report, DSI is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Spray Dryer Absorption (SDA)**

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO<sub>2</sub> is absorbed by the slurry, forming CaSO<sub>3</sub>/CaSO<sub>4</sub>. 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. The normal SO<sub>2</sub> control efficiency range for SDA is up to 90%.

Based on the information contained with this report, SDA is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption, which results in lower operating costs. Typically, reduced fuel usage translates into reduced pollution emissions. Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

## **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has also pushed companies to evaluate alternate fuel sources. These fuel sources come in all forms – solid, liquid and gas. To achieve reduction of SO<sub>2</sub> emissions through alternative fuel usage, the source must be capable of burning fuels with lower sulfur content than the existing fuels. The process boilers are only permitted to burn natural gas and used oil, which are both low in sulfur content. Therefore SO<sub>2</sub> emission reductions through the use of alternate fuels are not an option and are not applicable to the process boilers.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as their option, not to direct the fuel choice.<sup>36</sup>

Therefore, due to the limited fuel burning capabilities of the boilers and the fact that BART is not intended to mandate a fuel switch, alternative fuels as an air pollution control technology will not be further evaluated in this report.

However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

## **Coal Processing**

Since the process boilers are not capable of burning solid fuel, this option is not applicable for SO<sub>2</sub> reductions.

## **STEP 2 Conclusion**

Based upon the determination within Step 2, the remaining SO<sub>2</sub> control technologies that are available and applicable to the process boilers are identified in Table 5-17. The technical feasibility as determined in Step 2 is also included in Table 5-17.

---

<sup>36</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

**Table 5-17 Process Boiler SO<sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility**

SO <sub>2</sub> Pollution Control Technology	Available?	Applicable?	Technically Feasible?
WWESP	Yes	Yes	Yes
Wet Scrubber	Yes	Yes	Yes
Spray Dry Absorption (SDA)	Yes	Yes	Yes
Dry Sorbent Injection (DSI)	Yes	Yes	Yes
Energy Efficiency Projects	Yes	Yes	Project Dependent
Alternative Fuels	Yes	Yes	Yes - Not Required by BART

**5.B.i.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies**

Table 5-18 describes the expected control efficiency from each of the remaining feasible control options when burning liquid fuels.

**Table 5-18 Process Boiler SO<sub>2</sub> Control Technology Effectiveness**

SO <sub>2</sub> Pollution Control Technology	Approximate Control Efficiency
SDA	90%
Wet Scrubbing (High Efficiency)	80%
WWESP	80%
DSI	55%

**5.B.i.d STEP 4 – Evaluate Impacts and Document the Results**

As illustrated in Table 5-18 above, the technically feasible control remaining provide varying levels of emission reduction. Therefore, it is necessary to consider the economic, energy, and environmental impacts to better differentiate as presented below.

**Economic Impacts**

Table 5-19 details the expected costs associated with installation of the above alternatives on each stack. Equipment design was based on the maximum 24-hour emissions, vendor estimates, and U.S.

EPA cost models. Capital costs were based on a recent vendor quotation. The cost for that unit was scaled to each stack's flow rate using the six-tenths-factor rule<sup>37</sup> as shown in the following equation:

$$\text{Cost of equipment A} = \text{Cost of equipment B} * (\text{capacity of A/capacity of B})^{0.6}$$

Direct and indirect costs were estimated as a percentage of the fixed capital investment using U.S. EPA models and factors. Operating costs were based on 93% utilization and 7650 operating hours per year, which is very conservative, considering these are backup boilers. Operating costs of consumable materials, such as electricity, water, and chemicals were established based on the U.S. EPA control cost manual<sup>38</sup> and engineering experience, and were adjusted for the specific flow rates and pollutant concentrations.

The detailed cost analysis is provided in Appendix A.

**Table 5-19 Process Boilers 1 and 2 SO<sub>2</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (\$)</b>	<b>Total Annual Cost (\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>
SDA	\$56,323,180	\$8,640,697	\$38,403,097
Wet Scrubber	\$9,309,297	\$1,489,576	\$7,447,882
WWESP	\$17,123,526	\$3,146,592	\$15,732,959
DSI	\$32,010,048	\$4,892,432	\$35,581,325

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater

<sup>37</sup> M.S. Peters and K.D. Timmerhaus, December, 2002 *Plant Design and Economics for Chemical Engineers, Fifth Edition*.

<sup>38</sup> U.S. EPA, January 2002, *EPA Air Pollution Control Cost Manual, Sixth Edition*.

business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>39</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts. Based on the information presented in table 5-19, the annualized pollution control costs for all of the technologies are above the \$12,000 threshold. Therefore, no additional analysis for visibility improvement, energy and other impacts is required.

The BART guidance documents also present a calculation method for incremental control cost which is intended to present the incremental value of each technology as compared to the next most effective alternative. Since none of the technologies are cost effective, the incremental control cost is not applicable and is not presented in this analysis.

### **Energy and Environmental Impacts**

Since none of the SO<sub>2</sub> technologies are cost effective for the process boilers, the energy and non-air quality impacts were not assessed for the SO<sub>2</sub> control equipment technologies for the process boilers.

#### **5.B.i.e STEP 5 – Evaluate Visibility Impacts**

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. Since none of the SO<sub>2</sub> technologies are cost effective for the process boilers, the visibility impacts were not evaluated.

---

<sup>39</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

## 5.B.ii Nitrogen Oxide Controls

To be able to control  $\text{NO}_x$  it is important to understand how  $\text{NO}_x$  is formed. There are three mechanisms by which  $\text{NO}_x$  production occurs: thermal, fuel and prompt  $\text{NO}_x$ .

- Fuel bound  $\text{NO}_x$  is formed as nitrogen compounds in the fuel is oxidized in the combustion process.
- Thermal  $\text{NO}_x$  production arises from the thermal dissociation of nitrogen and oxygen molecules within the furnace. Combustion air is the primary source of nitrogen and oxygen. Thermal  $\text{NO}_x$  production is a function of the residence time, free oxygen, and temperature.
- Prompt  $\text{NO}_x$  is a form of thermal  $\text{NO}_x$  which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of  $\text{NO}_x$  are emitted as prompt  $\text{NO}_x$ .

The majority of  $\text{NO}_x$  is emitted as NO. Minor amounts of  $\text{NO}_2$  are formed in the boiler.

### 5.B.ii.a STEP 1 – Identify All Available Retrofit Control Technologies

With the understanding of how  $\text{NO}_x$  is formed, available and applicable control technologies were evaluated. See Appendix F for the current status of the availability and applicability of retrofit control technologies. Many emerging technologies have been identified that are not currently commercially available. A preliminary list of technologies was submitted to MDEQ on October 6, 2006 with the status of the technology as it was understood at that time. As work on this evaluation progressed, new information became apparent of the limited scope and scale of some of the technology applications. Appendix F presents the current status of the general availability of each technology.

### 5.B.ii.b STEP 2 – Eliminate Technically Infeasible Options

Step 1 identified the available and applicable technologies for  $\text{NO}_x$  emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit  $\text{NO}_x$  control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for process boilers.

### **External Flue Gas Recirculation (EFGR)**

External flue gas recirculation (EFGR) uses flue gas as an inert material to reduce flame temperatures thereby reducing thermal NO<sub>x</sub> formation. 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 NO<sub>x</sub> emissions. For this technology to be effective, the combustion conditions must have the ability to be controlled at the burner tip. Due to the current configuration of the burners, Process boilers 1 and 2 do not have the capability of control at the burner tip. Therefore, this option is not technically feasible and will not be further evaluated in this report.

### **Low NO<sub>x</sub> Burners (LNB)**

Low-NO<sub>x</sub> burner (LNB) technology utilizes advanced burner design to reduce NO<sub>x</sub> 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. In the primary zone, NO<sub>x</sub> formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NO<sub>x</sub> formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NO<sub>x</sub> formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO<sub>x</sub> formation. Low NO<sub>x</sub> burners typically achieve NO<sub>x</sub> emission reductions of 25% - 50% for process boilers.

Based on the information contained within this report, LNB is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Overfire Air (OFA)**

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is a NO<sub>x</sub> control technology typically used in boilers and is primarily geared to reduce thermal NO<sub>x</sub>. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NO<sub>x</sub> by lowering peak combustion temperature and limiting the availability of

oxygen in the combustion zone where NO<sub>x</sub> is most likely to be formed. OFA is considered compatible with the LNB. The estimated NO<sub>x</sub> control efficiency for LNB with OFA is 50-67%.

Based on the information contained within this report, OFA with LNB is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Induced Flue Gas Recirculation (IFGR)**

Induced flue gas recirculation burners, also called ultra low-NO<sub>x</sub> burners, combine the benefits of flue gas recirculation and low-NO<sub>x</sub> 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 NO<sub>x</sub> control efficiency for IFGR burners in high temperature applications is 50-75%.

Based on the information contained within this report, IFGR is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption. Typically reduced fuel usage translates into reduced pollution emissions. An energy efficiency project could be preheat incoming make-up air or pellet feed. Each project is very dependent upon the fuel usage, process equipment, type of product and so many other variables.

Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potential emission reductions. Due to the uncertainty and generalization of this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

### **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has also pushed companies to evaluate alternate fuel sources. These fuel sources come in all forms – solid, liquid and gas. To achieve reduction of NO<sub>x</sub> emissions through alternative fuel usage, the source must be currently burning a high NO<sub>x</sub> emitting fuel relative to other fuels. The boilers are only capable of burning natural gas and distillate oil. Therefore the use of alternate fuels is not a viable option for the process boilers and will not be considered further in this analysis.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as their option, not to direct the fuel choice.<sup>40</sup>

Therefore, due to the limited boiler fuel capabilities and the fact that BART is not intended to mandate a fuel switch, alternative fuels as an air pollution control technology will not be further evaluated in this report

However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

### **Low Excess Air**

Operating a boiler with low excess air is a method to minimize peak flame temperature and excess oxygen which therefore minimizes the production of NO<sub>x</sub>. Operating a boiler with low excess air also optimizes the fuel efficiency as less air is heated up in the combustion chamber.

As previously stated, the increased price of fuel has pushed companies to evaluate fuel usage. Therefore, the boilers at Tilden are operated with low excess air within the constraints of the boilers. Therefore, low excess air will not be further evaluated in this report. However, similar to energy efficiency and alternate fuels, the facility will continue to evaluate boiler optimization including operating at low excess air.

### **Reburning**

Reburning is a technology used with solid fuels. Process boilers are not cable of burning solid fuel, therefore this technology will not be further evaluated.

### **Post Combustion Controls**

NO<sub>x</sub> can be controlled using add-on systems located downstream of the combustion process. The two main techniques in commercial service include the selective non catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing,

---

<sup>40</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

absorbing, or adsorbing NO<sub>x</sub> downstream of the combustion chamber. Examples of these alternatives are nonselective catalytic reduction (NSCR) and Low Temperature Oxidation (LTO). Each of these alternatives is described below.

### **Non-Selective Catalytic Reduction (NSCR)**

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR catalyst is very sensitive to poisoning; therefore, NSCR is applied primarily in natural gas combustion applications.

NSCR is often referred to as “three-way conversion” catalyst because it simultaneously reduces NO<sub>x</sub>, unburned hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO<sub>x</sub> emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under this condition, in the presence of a catalyst, NO<sub>x</sub> is reduced by CO, resulting in nitrogen (N<sub>2</sub>) and carbon dioxide (CO<sub>2</sub>). The most important reactions for NO<sub>x</sub> removal are:



NSCR catalyst has been applied primarily in clean combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, making it infeasible to apply this technology to liquid fuels. Therefore, this technology will not be further evaluated in this report.

### **Selective Catalytic Reduction (SCR) and Regenerative Selective Catalytic Reduction (R-SCR)**

SCR is a post-combustion NO<sub>x</sub> control technology in which ammonia (NH<sub>3</sub>) is injected into the flue gas stream in the presence of a catalyst. NO<sub>x</sub> is removed through the following chemical reaction:



A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO<sub>x</sub> decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670°F, the oxidation of ammonia begins to become significant. At low temperatures, the formation of ammonium bisulfate causes scaling and corrosion problems.

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.

Ammonia slip from the SCR system is usually less than 3 to 5 ppm. The emission of ammonia increases during load changes due to the instability of the temperature in the catalyst bed as well as at low loads because of the low gas temperature.

Regenerative Selective Catalytic Reduction (R-SCR) applies the Selective Catalytic Reduction (SCR) control process as described below with a preheat process step to reheat the flue gas stream up to SCR catalyst operating temperatures. The preheating process combines use of a thermal heat sink (packed bed) and a duct burner. The thermal sink recovers heat from the hot gas leaving the R-SCR and then transfers that heat to gas entering the R-SCR. The duct burner is used to complete the preheating process. R-SCR operates with several packed bed/SCR reactor vessels. Gas flow alternates between vessels. Each of the vessels alternates between preheating/treating and heat recovery.

The benefits of R-SCR are:

- Its high energy efficiency allows it to be used after SO<sub>2</sub> and particulate controls.
- R-SCR has a thermal efficiency of 90% - 95% vs. standard heat exchangers which have a thermal efficiency of 60% to 70%.
- Application of R-SCR after SO<sub>2</sub> and PM controls significantly reduces the potential for problems associated with plugging and catalyst poisoning and deactivation.

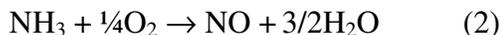
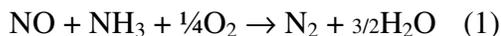
To date, R-SCR has been applied to wood-fired utility boilers. Application of this technology has not been applied to liquid and natural gas fired boilers. Using RSCR would require research, test runs, and extended trials to identify potential issues related to catalyst selection, and impacts on plant systems. It is not reasonable to assume that vendor guarantees of performance would be forthcoming in advance of a demonstration project. The timeline required to perform such a demonstration project would likely be two years to develop and agree on the test plan, obtain permits for the trial, commission the equipment for the test runs, perform the test runs for a reasonable study period, and evaluate and report on the results. The results would not be available within the time window for establishing emission limits to be incorporated in the state implementation plan (SIP) by December 2007.

Recalling U.S. EPA's intention regarding "available" technologies to be considered for BART, as mentioned in Section 2.B, facility owners are not expected to undergo extended trials in order to learn how to apply a control technology to a completely new and significantly different source type. Therefore, R-SCR is not considered to be technically feasible, and will not be analyzed further in this BART analysis.

SCR with reheat through a conventional duct burner (rather than using a regenerative heater) has been successfully implemented more widely and in higher airflow applications and will be carried forward in this analysis as available and applicable technology that is reasonably expected to be technically feasible.

### **Selective Non-Catalytic Reduction (SNCR)**

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N<sub>2</sub>, and water. SNCR control efficiency is typically 25% - 60%. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:



At temperature ranges of 1470 to 1830°F reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate.

Based on the information contained within this report, a SNCR is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Low Temperature Oxidation (LTO)**

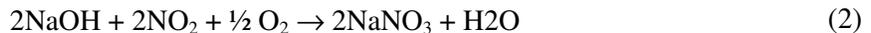
The LTO system utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO<sub>x</sub>. In the system, the NO<sub>x</sub> in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution forming sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system. Commercially available LTO systems include Tri-NO<sub>x</sub>® and LoTOx®.





### **Low Temperature Oxidation (Tri-NO<sub>x</sub><sup>®</sup>)**

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO<sub>2</sub> in a primary scrubbing stage. Then NO<sub>2</sub> is removed through caustic scrubbing in a secondary stage. The reactions are as follows:



Tri-NO<sub>x</sub><sup>®</sup> is a multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO<sub>2</sub>. Subsequent stages reduce NO<sub>2</sub> to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-NO<sub>x</sub><sup>®</sup> is typically applied at small to medium sized sources with high NO<sub>x</sub> concentration in the exhaust gas (1,000 ppm NO<sub>x</sub>).

### **Low Temperature Oxidation (LoTOx<sup>®</sup>)**

BOC Gases' Lo-TOx<sup>®</sup> is an example of a version of an LTO system. LoTOx<sup>®</sup> technology uses ozone to oxidize NO to NO<sub>2</sub> and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N<sub>2</sub>O<sub>5</sub> is converted to HNO<sub>3</sub> in a scrubber, and is removed with lime or caustic. Ozone for LoTOx<sup>®</sup> is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO<sub>x</sub> control. Ozone is generated from pure oxygen. In order for LoTOx<sup>®</sup> to be economically feasible, a source of low cost oxygen must be available from a pipeline or on site generation.

In addition, only two of BOC's LoTOx<sup>®</sup> installations are fully installed and operational applications. Therefore, although this is an emerging technology, the limited application means that it has not been

demonstrated to be an effective technology in widespread application. Consequently, the technical feasibility of LTO as technically infeasible for this application and will not be evaluated further.

## Step 2 Conclusion

Based upon the determination within Step 2, the remaining NO<sub>x</sub> control technologies that are available and applicable to the process boilers are identified in Table 5-20. The technical feasibility as determined in Step 2 is also included in Table 5-20.

**Table 5-20 Process Boilers 1 and 2 NO<sub>x</sub> Control Technology – Availability, Applicability and Technical Feasibility**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Available?</b>	<b>Applicable?</b>	<b>Technically Feasible?</b>
External Flue Gas Recirculation (EFGR)	Yes	Yes	No
Low-NO <sub>x</sub> Burners (LNB)	Yes	Yes	Yes
Low NO <sub>x</sub> Burners with Overfired Air (LNB/OFA)	Yes	Yes	Yes
Induced Flue Gas Recirculation (IFGR)	Yes	Yes	Yes
Low Excess Air	Yes	Yes	Yes (already implemented)
Reburning	Yes	Yes	No
Energy Efficiency Projects	Yes	Yes	Project Dependent
Alternative Fuels	Yes	Yes	Yes - Not Required by BART
Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	Yes
Selective Catalytic Reduction (SCR)	Yes	Yes	Yes
Regenerative SCR	Yes	Yes	No
Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes
Low Temperature Oxidation (LTO)	Yes	No	No

### 5.B.ii.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 5-21 describes the expected control efficiency from the remaining technically feasible control option as identified in Step 2.

**Table 5-21 Process Boiler NO<sub>x</sub> Control Technology Effectiveness**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Approximate Control Efficiency</b>
Selective Catalytic Reduction (SCR) with Reheat	80%
Low NOX Burner / Flue Gas Recirculation (LNB/FGR)	75%
Regenerative Selective Catalytic Reduction (R-SCR)	70%
Low NOX Burner / Overfire Air (LNB/OFA)	67%
Low NOX Burner (LNB)	50%
Selective Non-Catalytic Reduction (SNCR)	50%

**5.B.ii.d STEP 4 – Evaluate Impacts and Document the Results**

Table 5-22 details the expected costs associated with installation of NO<sub>x</sub> controls. Capital costs were calculated based on the maximum 24-hour emissions, U.S. EPA cost models, and vendor estimates. Vendor estimates for capital costs based on a specific flow rate were scaled to each stack's flow rate using the 6/10 power law to account for the economy of scale. Operating costs were based on 93% utilization and 7650 operating hours per year, which is extremely conservative, since they are backup boilers. Operating costs were proportionally adjusted to reflect site specific flow rates and pollutant concentrations.

After a tour of the facility and discussions with facility management, it was determined the space surrounding the boilers is congested and the area surrounding the building supports vehicle and rail traffic to transport materials to and from the building. A site-specific estimate for site-work, foundations, and structural steel was added based upon the facility site to arrive at the total retrofit installed cost of the control technology. See Appendix C for a site plan of the facility. Additionally, the structural design of the existing building would not support additional equipment on the roof. The detailed cost analysis is provided in Appendix A.

**Table 5-22 Process Boiler NO<sub>x</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (\$)</b>	<b>Total Annual Cost (\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>	<b>Incremental Control Cost (\$/ton)</b>
SCR with Reheat**	\$6,317,686	\$2,528,225	\$39,888	NA
LNB/FGR	\$2,190,300	\$270,904	\$4,559	Lowest
R-SCR**	\$16,117,290	\$3,303,391	\$59,563	NA
LNB/OFA	\$3,031,714	\$390,751	\$7,361	NA
LNB	\$1,320,909	\$286,968	\$7,244	NA
SNCR	\$1,501,420	\$426,135	\$10,760	NA*

\* Control efficiency is equal to the option with the lowest cost per ton, LNB at 50%.

\*\* SCR and R-SCR were eliminated from further consideration due to high cost per ton.

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>41</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts.

---

<sup>41</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

The incremental control cost listed in Table 5-22 represents the incremental value of each technology as compared to the technology with the next highest level of control. The cost of control and incremental cost of SCR with reheat, R-SCR and SNCR are not reasonable. The magnitude of the capital and operating costs of remaining alternatives is also significant and may impact the viability of continued operation.

### Energy and Environmental Impacts

The energy and non-air quality impacts for LNB and LNB with IFGR are presented in Table 5-23. Because the cost of the remaining NO<sub>x</sub> control technologies for the process boilers is so high and does not meet a reasonable definition of cost effective technology, these technologies are removed from further consideration in this analysis.

**Table 5-23 Process Boiler NO<sub>x</sub> Control Technology – Other Impacts Assessment**

Control Option	Energy Impacts	Other Impacts
LNB	- Minimal energy impacts	- Increase in CO emissions - Potential for steam tube wastage due to longer combustion flame
LNB/OFA	- Minimal energy impacts	- Increase in CO emissions - Potential for steam tube wastage due to longer combustion flame
LNB/FGR	- Minimal energy impacts.	- Increase in CO emissions - Potential for steam tube wastage due to longer combustion flame.

### 5.B.ii.eSTEP 5 – Evaluate Visibility Impacts

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. This section of the report evaluates the visibility impacts of BART NO<sub>x</sub> control and the resulting degree of visibility improvement.

### Predicted 24-Hour Maximum Emission Rates

Consistent with the use of the highest daily emissions for baseline, or pre-BART, visibility impacts, the post-BART emissions to be used for the visibility impacts analysis should also reflect a

maximum 24-hour average project emission rate. In the visibility impacts NO<sub>x</sub> modeling analysis, the emissions from the sources undergoing a full BART NO<sub>x</sub> analysis were adjusted to reflect the projected 24-hour maximum NO<sub>x</sub> emission rate when applying the control technologies that met the threshold requirements of steps 1 – 4. The emissions from all other Subject-to-BART sources were not changed. Table 5-24 provides a summary of the modeled 24-hour maximum emission rates and their computational basis for the evaluated NO<sub>x</sub> control technologies. Table 5-25 provides a summary of the modeling input data.

### **Post-BART Visibility Impacts Modeling Results**

Results of the post-BART visibility impacts modeling for NO<sub>x</sub> for the process boilers are presented in Table 5-26. The results summarize 98th percentile dV value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas. The comparison of the post-BART modeling scenarios to the baseline conditions is presented in Table 5-27.

Visibility impacts with SO<sub>2</sub> controls are presented in section 6.

**Table 5-27 Process Boiler Post-BART Modeling Scenarios**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
8	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
9	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
10	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
12	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
13	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
14	SVP0051981	EUKILN1	Wet Scrubber	Good Combustion	80%	40.0	0.0%	800.9

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0051711			Practice	80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
15	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
	SVP0051711				80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
16	SVP0051981	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2	0.0%	800.9
	SVP0051711					72.8		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
17	SVP0051981	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2	80%	160.2
	SVP0051711					72.8	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
18	SVP0051981	EUKILN1	Wet Scrubber	Good Combustion Practice	80%	40.0	0.0%	800.9
	SVP0051711				80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
19	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
	SVP0051711				80%	14.6	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
20	SVP0051981	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2	0.0%	800.9
	SVP0051711					72.8		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
21	SVP0051981	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2	80%	160.2
	SVP0051711					72.8	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
22	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
24	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
25	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
26	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
27	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
28	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
29	SVP0051981	EUKILN1	Low Sulfur Coal	SCR w/reheat	0.0%	200.2	80%	160.2

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0051711		Natural Gas			72.8	80%	58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
30	SVP0051981	EUKILN1	Wet Scrubber	Good Combustion Practice	80%	40.0	0.0%	800.9
	SVP0051711				80%	14.6		291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
31	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	80%	40.0	80%	160.2
	SVP0051711				80%	14.6		58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

**Table 5-28 Process Boiler Post-BART NO<sub>x</sub> Modeling Scenarios - Modeling Input Data**

Control Scenario	SV #	Emission Unit	Stack Easting (utm)	Stack Northing (utm)	Height of Opening from Ground (ft)	Base Elevation of Ground (ft)	Stack length, width, or Diameter (ft)	Flow Rate at exit (acfm)	Exit Temp (°F)
All Scenarios	SVP0051981 SVP0051711	EUKILN1	46.44084994	-87.653 40738	240	1474	19.3	842,000	300
			46.44075383	-87.651 32336	160		13.5	306,000	300
	SVP0082951	EUDRYER1	46.44075383	-87.651 32336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.654 12418	130	1474	7.5	192,000	350

**Table 5-29 Process Boiler Post-BART NO<sub>x</sub> Modeling Scenarios - Visibility Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV	Modeled 98%ile ΔdV	# days over 0.5 ΔdV
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
8	IRNP	0.714	19.0	0.711	11.000	0.583	11.000	0.653	41
9	IRNP	0.314	2.0	0.252	0.000	0.213	1.000	0.248	2
10	IRNP	0.618	15.0	0.607	10.000	0.527	8.000	0.590	33
11	IRNP	0.176	0.0	0.168	0.000	0.150	0.000	0.161	0
12	IRNP	0.719	19.0	0.693	10.000	0.592	9.000	0.654	38
13	IRNP	0.315	2.0	0.246	0.000	0.218	1.000	0.243	2
14	IRNP	0.627	15.0	0.608	9.000	0.544	8.000	0.585	32
15	IRNP	0.176	0.0	0.171	0.000	0.150	0.000	0.160	0
16	IRNP	0.722	19.0	0.673	10.000	0.605	9.000	0.656	38
17	IRNP	0.326	2.0	0.243	0.000	0.218	1.000	0.243	2
18	IRNP	0.626	15.0	0.605	9.000	0.542	8.000	0.596	32
19	IRNP	0.175	0.0	0.173	0.000	0.151	0.000	0.163	0
20	IRNP	0.734	19.0	0.692	10.000	0.605	10.000	0.654	39
21	IRNP	0.324	2.0	0.241	0.000	0.215	1.000	0.241	2
22	IRNP	0.625	15.0	0.602	9.000	0.291	3.000	0.588	27
23	IRNP	0.175	0.0	0.170	0.000	0.150	0.000	0.165	0
24	IRNP	0.727	19.0	0.689	10.000	0.603	10.000	0.656	39
25	IRNP	0.326	2.0	0.245	0.000	0.207	1.000	0.241	2
26	IRNP	0.623	15.0	0.605	9.000	0.550	8.000	0.597	32
27	IRNP	0.176	0.0	0.172	0.000	0.151	0.000	0.165	0
28	IRNP	0.704	19.0	0.672	10.000	0.606	9.000	0.657	38
29	IRNP	0.325	2.0	0.239	0.000	0.198	1.000	0.240	2
30	IRNP	0.613	14.0	0.614	9.000	0.542	8.000	0.588	31
31	IRNP	0.173	0.0	0.172	0.000	0.151	0.000	0.164	0

**Table 5-30 Process Boiler Post-BART NO<sub>x</sub> Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV
8	IRNP	0	0	0.011	0	0.016	0	0.021	0
9	IRNP	0.4	17	0.47	11	0.386	10	0.426	39
10	IRNP	0.096	4	0.115	1	0.072	3	0.084	8
11	IRNP	0.538	19	0.554	11	0.449	11	0.513	41
12	IRNP	-0.005	0	0.029	1	0.007	2	0.02	3
13	IRNP	0.399	17	0.476	11	0.381	10	0.431	39
14	IRNP	0.087	4	0.114	2	0.055	3	0.089	9
15	IRNP	0.538	19	0.551	11	0.449	11	0.514	41
16	IRNP	-0.008	0	0.049	1	-0.006	2	0.018	3
17	IRNP	0.388	17	0.479	11	0.381	10	0.431	39
18	IRNP	0.088	4	0.117	2	0.057	3	0.078	9
19	IRNP	0.539	19	0.549	11	0.448	11	0.511	41
20	IRNP	-0.02	0	0.03	1	-0.006	1	0.02	2
21	IRNP	0.39	17	0.481	11	0.384	10	0.433	39
22	IRNP	0.089	4	0.12	2	0.308	8	0.086	14
23	IRNP	0.539	19	0.552	11	0.449	11	0.509	41
24	IRNP	-0.013	0	0.033	1	-0.004	1	0.018	2
25	IRNP	0.388	17	0.477	11	0.392	10	0.433	39
26	IRNP	0.091	4	0.117	2	0.049	3	0.077	9
27	IRNP	0.538	19	0.55	11	0.448	11	0.509	41
28	IRNP	0.01	0	0.05	1	-0.007	2	0.017	3
29	IRNP	0.389	17	0.483	11	0.401	10	0.434	39
30	IRNP	0.101	5	0.108	2	0.057	3	0.086	10
31	IRNP	0.541	19	0.55	11	0.448	11	0.51	41

## **5.C Line 1 Dryer**

The Line 1 Dryer requires a BART analysis. This Line 1 Dryer includes a combustion box in which natural gas and used oil is burned as fuel. The flue gas from the combustion box flows into a rotary dryer that repeatedly tumbles wet taconite ore concentrate through the flue gas stream to reduce the amount of entrained moisture in the taconite ore concentrated. The particulate emissions from the dryer are controlled by cyclones and impingement scrubbers in series. The dryer is only permitted to use natural gas and used oil for fuel.

### **5.C.i Sulfur Dioxide Controls**

Sulfur in the fuel is the only source of SO<sub>2</sub> emissions from the dryer. The Line 1 Dryer has low emissions of SO<sub>2</sub> due to the low sulfur content of the permitted fuels. In addition, collateral SO<sub>2</sub> reductions occur within the existing impingement scrubbers, and therefore the existing scrubber is considered a low-efficiency SO<sub>2</sub> scrubber.

#### **5.C.i.a STEP 1 – Identify All Available Retrofit Control Technologies**

See Appendix F for a comprehensive list of all potential retrofit control technologies that were evaluated. Many emerging technologies have been identified that are not currently commercially available. A preliminary list of technologies was submitted to MDEQ on October 6, 2006 with the status of the technology as it was understood at that time. As work on this evaluation progressed, new information became apparent of the limited scope and scale of some of the technology applications. Appendix F presents the current status of the general availability of each technology.

#### **5.C.i.b STEP 2 – Eliminate Technically Infeasible Options**

Step 1 identified the available and applicable technologies for SO<sub>2</sub> emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO<sub>2</sub> control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for indurating furnaces.

#### **Wet Walled Electrostatic Precipitator (WWESP)**

An electrostatic precipitator (ESP) 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.

A wet walled electrostatic precipitator (WWESP) operates on the same collection principles as a dry ESP and uses a water spray to remove particulate matter from the collection plates. For SO<sub>2</sub> removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO<sub>2</sub> absorber.

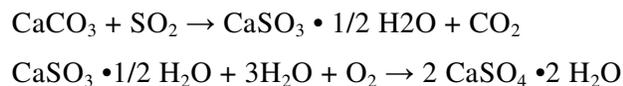
The SO<sub>2</sub> control efficiency for a WWESP is dependent upon various process specific variables, such as SO<sub>2</sub> flue gas concentration and fuel used. Since Line 1 Dryer currently employs a wet scrubber designed for removal of particulate matter, the scrubber also performs as a low efficiency SO<sub>2</sub> wet scrubber. The addition of a WWESP would act as a polishing SO<sub>2</sub> control device and would experience reduced control efficiency due to lower SO<sub>2</sub> inlet concentrations.

Based on the information contained within this report, a WWESP is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

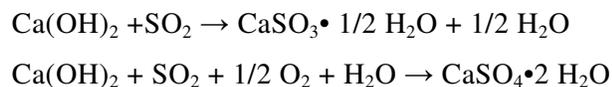
### **Wet Scrubbing (High and Low Efficiency)**

Wet scrubbing, when applied to remove SO<sub>2</sub>, is generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO<sub>2</sub> in the waste gas. Crushed limestone, lime or Caustic is used as scrubbing agents.

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:



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:



When that caustic (sodium hydroxide solution) is the scrubbing agent, the SO<sub>2</sub> removal reactions are as follows:



Caustic scrubbing produces a liquid waste, and minimal equipment is needed as compared to lime or limestone scrubbers. If lime or limestone is used as the reagent for SO<sub>2</sub> 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<sub>2</sub> control efficiency range for SO<sub>2</sub> scrubbers on coal fired utility boilers is 80% to 90% for low efficiency scrubbers and 90% and more for high efficiency scrubbers. The highest control efficiencies can be achieved when SO<sub>2</sub> concentrations are the highest. The dryer and process boiler's exhaust would not have a high SO<sub>2</sub> concentration, so the low end of the efficiency range would be expected.

As stated in the beginning of this section, a wet scrubber is currently in place on the Line 1 Dryer and is believed to remove approximately 30% of the SO<sub>2</sub> in the exhaust. The addition of an additional SO<sub>2</sub> scrubber would act as a polishing SO<sub>2</sub> control device and would experience reduced control efficiency due to lower SO<sub>2</sub> inlet concentrations.

A Minnesota taconite facility has evaluated modifying the exiting scrubber on the kiln exhaust, which is similar to the dryer exhaust stream, to determine if improvements to SO<sub>2</sub> removal could be accomplished. The concentration of caustic in the scrubbing water was increased to a pH of 8 for several hours and stack sampling was performed to evaluate the change in SO<sub>2</sub> emissions. The SO<sub>2</sub> emissions were not reduced. The materials of construction of the existing scrubbers would not withstand a higher pH than 7 or 8. An engineering study would be required to evaluate more extensive redesign of the existing scrubbers, such as modifying the spray, increasing the contact time, recirculating the scrubber water, and retrofitting to allow use of a much higher pH. Quantifying the likelihood and magnitude of potential improvements to SO<sub>2</sub> control would not be possible without a study, so this option could not be selected as BART.

Based on the information contained within this report, a wet scrubber is considered a technically feasible technology for SO<sub>2</sub> reduction for this BART analysis.

### **Dry Sorbent Injection (Dry Scrubbing Lime/Limestone Injection)**

Dry sorbent injection (DSI) of lime/limestone is a post-combustion SO<sub>2</sub> control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO<sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO<sub>2</sub> removal occurs as the flue gas flows through the filter cake on the bags. The normal SO<sub>2</sub> control efficiency range for dry SO<sub>2</sub> scrubbers is 70% to 90 % for coal fired utility boilers.

The Line 1 Dryer flue gas stream is high in water content and is exhausted at or near their dew points. Exhaust gases leaving the Line 1 Dryer is currently treated for removal of particulate matter using a wet scrubber. Due to the high water content in the dryer flue gas, the baghouse filter cake would become saturated with moisture and plug both the filters and the dust removal system. Although this may be an available and applicable control option, it is not technically feasible due to the high moisture content and will not be further evaluated in this report for the Line 1 Dryer.

### **Spray Dryer Absorption (SDA)**

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO<sub>2</sub> is absorbed by the slurry, forming CaSO<sub>3</sub>/CaSO<sub>4</sub>. 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. The normal SO<sub>2</sub> control efficiency range for SDA is up to 90%.

The Line 1 Dryer flue gas stream is high in water content and is exhausted at or near their dew points. Gases leaving the dryer are currently treated for removal of particulate matter using a wet scrubber. The exhaust temperature is typically in the range of 100 °F to 150 °F and is saturated with water. For comparison, a utility boiler exhaust operates at 350 °F or higher and is not saturated with water. Under dryer conditions, the baghouse filter cake would become saturated with moisture and plug both the filters and the dust removal system. Although this may be an available and applicable control option, it is not technically feasible due to the high moisture content and will not be further evaluated in this report.

### **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption, which results in lower operating costs. Typically, reduced fuel usage translates into reduced pollution emissions. Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potentially emission reductions. Due to the uncertainty and generalization of this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

### **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has also pushed companies to evaluate alternate fuel sources. These fuel sources come in all forms – solid, liquid and gas. To achieve reduction of SO<sub>2</sub> emissions through alternative fuel usage, the source must be capable of burning fuels with lower sulfur content than the existing fuels. The Line 1 Dryer is only permitted to burn natural gas and used oil, which are both low in sulfur content. Therefore SO<sub>2</sub> emission reductions through the use of alternate fuels are not an option and are not applicable to the Line 1 Dryer.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as their option, not to direct the fuel choice.<sup>42</sup>

---

<sup>42</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

Therefore, due to the limited fuel burning capabilities of the Line 1 Dryer and the fact that BART is not intended to mandate a fuel switch, alternative fuels as an air pollution control technology will not be further evaluated in this report.

However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

### **Coal Processing**

Since the Line 1 Dryer is not permitted to burn solid fuel, this option is not applicable for SO<sub>2</sub> reductions.

### **STEP 2 Conclusion**

Based upon the determination within Step 2, the remaining SO<sub>2</sub> control technologies that are available and applicable to the Line 1 Dryer are identified in Table 5-29. The technical feasibility as determined in Step 2 is also included in Table 5-29.

**Table 5-29 Line 1 Dryer SO<sub>2</sub> Control Technology – Availability, Applicability, and Technical Feasibility**

SO <sub>2</sub> Pollution Control Technology	Available?	Applicable?	Technically Feasible?
WWESP	Yes	Yes	Yes
Wet Scrubber	Yes	Yes	Yes
Spray Dry Absorption (SDA)	Yes	Yes	No
Dry Sorbent Injection (DSI)	Yes	Yes	No
Energy Efficiency Projects	Yes	Yes	Project Dependent
Alternative Fuels	Yes	Yes	Yes – Not required by BART

**5.C.i.c STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies**

Table 5-30 describes the expected control efficiency from each of the remaining feasible control options for the Line 1 Dryer.

**Table 5-30 Line 1 Dryer SO<sub>2</sub> Control Technology Effectiveness**

SO <sub>2</sub> Pollution Control Technology	Approximate Control Efficiency
Wet Scrubbing (High Efficiency)	80%
Wet Walled Electrostatic Precipitator (WWESP)	80%

**5.C.i.d STEP 4 – Evaluate Impacts and Document the Results**

As illustrated in Table 5-30 above, the technically feasible control remaining provide varying levels of emission reduction. Therefore, it is necessary to consider the economic, energy, and environmental impacts to better differentiate as presented below.

**Economic Impacts**

Table 5-31 details the expected costs associated with installation of a WWESP and wet scrubber. Equipment design was based on the maximum 24-hour emissions, vendor estimates, and U.S. EPA cost models. Capital costs were based on a recent vendor quotation. The cost for that unit was scaled to each stack’s flow rate using the six-tenths-factor rule as shown in the following equation:

$$\text{Cost of equipment A} = \text{Cost of equipment B} * (\text{capacity of A/capacity of B})^{0.6}$$

Direct and indirect costs were estimated as a percentage of the fixed capital investment using U.S. EPA models and factors. Operating costs were based on 100% utilization and 7650 operating hours per year, which is very conservative based on historic operating data. Operating costs of consumable materials, such as electricity, water, and chemicals were established based on the U.S. EPA control cost manual<sup>43</sup> and engineering experience, and were adjusted for the specific flow rates and pollutant concentrations.

See Appendix C for an aerial photo of the facility. The detailed cost analysis is provided in Appendix A.

**Table 5-31 Line 1 Dryer SO<sub>2</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (\$)</b>	<b>Total Annual Cost (\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>
<b>Wet Scrubber</b>	\$3,898,490	\$684,207	\$25,103
<b>Wet ESP (WWESP)</b>	\$7,674,618	\$1,429,065	\$52,432

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional

---

<sup>43</sup> U.S. EPA, January 2002, *EPA Air Pollution Control Cost Manual, Sixth Edition*.

impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>44</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts. However, as presented in table 5-31, all of the available and applicable technologies for SO<sub>2</sub> control for the Line 1 Dryer have annualized control costs greater than \$12,000 per ton of controlled pollutant. Therefore, no additional impacts analysis is required.

The BART guidance documents also present a calculation method for incremental control cost which is intended to present the incremental value of each technology as compared to the next most effective alternative. Since none of the technologies are cost effective, the incremental control cost is not applicable and is not presented in this analysis.

### **Energy and Environmental Impacts**

As presented in table 5-31, all of the available and applicable technologies for SO<sub>2</sub> control for the Line 1 Dryer have annualized control costs greater than \$12,000 per ton of controlled pollutant. Therefore, no energy and environmental impacts analysis was required.

### **5.C.i.e STEP 5 – Evaluate Visibility Impacts**

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. Since none of the SO<sub>2</sub> technologies are cost effective for the process boilers, the visibility impacts were not evaluated.

---

<sup>44</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

## 5.C.ii Nitrogen Oxide Controls

To be able to control  $\text{NO}_x$  it is important to understand how  $\text{NO}_x$  is formed. There are three mechanisms by which  $\text{NO}_x$  production occurs: thermal, fuel and prompt  $\text{NO}_x$ .

- Fuel bound  $\text{NO}_x$  is formed as nitrogen compounds in the fuel is oxidized in the combustion process.
- Thermal  $\text{NO}_x$  production arises from the thermal dissociation of nitrogen and oxygen molecules within the furnace. Combustion air is the primary source of nitrogen and oxygen. Thermal  $\text{NO}_x$  production is a function of the residence time, free oxygen, and temperature.
- Prompt  $\text{NO}_x$  is a form of thermal  $\text{NO}_x$  which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of  $\text{NO}_x$  are emitted as prompt  $\text{NO}_x$ .

The majority of  $\text{NO}_x$  is emitted as NO. Minor amounts of  $\text{NO}_2$  are formed in the dryer.

### 5.C.ii.a STEP 1 – Identify All Available Retrofit Control Technologies

With the understanding of how  $\text{NO}_x$  is formed, available and applicable control technologies were evaluated. See Appendix F for the current status of the availability and applicability of retrofit control technologies. Many emerging technologies have been identified that are not currently commercially available. A preliminary list of technologies was submitted to MDEQ on October 6, 2006 with the status of the technology as it was understood at that time. As work on this evaluation progressed, new information became apparent of the limited scope and scale of some of the technology applications. Appendix F presents the current status of the general availability of each technology.

### 5.C.ii.b STEP 2 – Eliminate Technically Infeasible Options

Step 1 identified the available and applicable technologies for  $\text{NO}_x$  emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit  $\text{NO}_x$  control technologies that were identified as available and applicable in the original submittal and discusses aspects of those technologies that determine whether or not the technology is technically feasible for the Line 1 Dryer.

### **External Flue Gas Recirculation (EFGR)**

External flue gas recirculation (EFGR) uses flue gas as an inert material to reduce flame temperatures thereby reducing thermal NO<sub>x</sub> formation. 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 NO<sub>x</sub> emissions. For this technology to be effective, the combustion conditions must have the ability to be controlled at the burner tip. Due to the current configuration of the burners, the Line 1 Dryer does not have the capability of control at the burner tip. Therefore, this option is not technically feasible and will not be further evaluated in this report.

### **Low NO<sub>x</sub> Burners (LNB)**

Low-NO<sub>x</sub> burner (LNB) technology utilizes advanced burner design to reduce NO<sub>x</sub> 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. In the primary zone, NO<sub>x</sub> formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NO<sub>x</sub> formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NO<sub>x</sub> formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO<sub>x</sub> formation. Low NO<sub>x</sub> burners typically achieve NO<sub>x</sub> emission reductions of 25% - 50% for process boilers.

Based on the information contained within this report, LNB is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Overfire Air (OFA)**

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is a NO<sub>x</sub> control technology typically used in boilers and is primarily geared to reduce thermal NO<sub>x</sub>. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NO<sub>x</sub> by lowering peak combustion temperature and limiting the availability of

oxygen in the combustion zone where NO<sub>x</sub> is most likely to be formed. OFA is considered compatible with the LNB. The estimated NO<sub>x</sub> control efficiency for LNB with OFA is 50-67%.

Based on the information contained within this report, OFA with LNB is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Induced Flue Gas Recirculation (IFGR)**

Induced flue gas recirculation burners, also called ultra low-NO<sub>x</sub> burners, combine the benefits of flue gas recirculation and low-NO<sub>x</sub> 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 NO<sub>x</sub> control efficiency for IFGR burners in high temperature applications is 50-75%.

Based on the information contained within this report, IFGR is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

### **Energy Efficiency Projects**

Energy efficiency projects provide opportunities for a company to reduce their fuel consumption. Typically reduced fuel usage translates into reduced pollution emissions. An energy efficiency project could be preheat incoming make-up air or pellet feed. Each project is very dependent upon the fuel usage, process equipment, type of product and so many other variables.

Due to the increased price of fuel, Tilden has already implemented energy efficiency projects. Each project carries its own fuel usage reductions and potential emission reductions. Due to the uncertainty and generalization of this category, this will not be further evaluated in this report. However, it should be noted that Tilden will continue to evaluate and implement energy efficiency projects as they arise.

### **Alternate Fuels**

As described within the energy efficiency description, increased price of fuel has also pushed companies to evaluate alternate fuel sources. These fuel sources come in all forms – solid, liquid and gas. To achieve reduction of NO<sub>x</sub> emissions through alternative fuel usage, the source must be currently burning a high NO<sub>x</sub> emitting fuel relative to other fuels. The Line 1 Dryer is only capable of burning natural gas and distillate oil. Therefore the use of alternate fuels is not a viable option for the Line 1 Dryer and will not be considered further in this analysis.

It is also important to note that U.S. EPA's intent is for facilities to consider alternate fuels as their option, not to direct the fuel choice.<sup>45</sup>

Therefore, due to the limited Line 1 Dryer fuel capabilities and the fact that BART is not intended to mandate a fuel switch, alternative fuels as an air pollution control technology will not be further evaluated in this report.

However, similar to energy efficiency, Tilden will continue to evaluate and implement alternate fuel usage as the feasibility arises.

### **Low Excess Air**

Operating a burner with low excess air is a method to minimize peak flame temperature and excess oxygen which therefore minimizes the production of NO<sub>x</sub>. Operating a burner with low excess air also optimizes the fuel efficiency as less air is heated up in the combustion chamber.

As previously stated, the increased price of fuel has pushed companies to evaluate fuel usage.

Therefore, the Line 1 Dryer at Tilden is operated with low excess air within the constraints of the combustion chamber. Therefore, low excess air will not be further evaluated in this report.

However, similar to energy efficiency and alternate fuels, the facility will continue to evaluate boiler optimization including operating at low excess air.

### **Reburning**

Reburning is a technology used with solid fuels. The Line 1 Dryer is not cable of burning solid fuel; therefore this technology will not be further evaluated.

### **Post Combustion Controls**

NO<sub>x</sub> can be controlled using add-on systems located downstream of the combustion process. The two main techniques in commercial service include the selective non catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing,

---

<sup>45</sup> Federal Register 70, no. 128 (July 6, 2005): 39164

absorbing, or adsorbing NO<sub>x</sub> downstream of the combustion chamber. Examples of these alternatives are nonselective catalytic reduction (NSCR) and Low Temperature Oxidation (LTO). Each of these alternatives is described below.

### **Non-Selective Catalytic Reduction (NSCR)**

A non-selective catalytic reduction (NSCR) system is a post combustion add-on exhaust gas treatment system. NSCR catalyst is very sensitive to poisoning; therefore, NSCR is applied primarily in natural gas combustion applications.

NSCR is often referred to as “three-way conversion” catalyst because it simultaneously reduces NO<sub>x</sub>, unburned hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO<sub>x</sub> emission reductions of 90 percent. In order to operate properly, the combustion process must be near stoichiometric conditions. Under this condition, in the presence of a catalyst, NO<sub>x</sub> is reduced by CO, resulting in nitrogen (N<sub>2</sub>) and carbon dioxide (CO<sub>2</sub>). The most important reactions for NO<sub>x</sub> removal are:



NSCR catalyst has been applied primarily in clean combustion applications. This is due in large part to the catalyst being very sensitive to poisoning, making it infeasible to apply this technology to liquid fuels. Therefore, this technology will not be further evaluated in this report.

### **Selective Catalytic Reduction (SCR) and Regenerative Selective Catalytic Reduction (R-SCR)**

SCR is a post-combustion NO<sub>x</sub> control technology in which ammonia (NH<sub>3</sub>) is injected into the flue gas stream in the presence of a catalyst. NO<sub>x</sub> is removed through the following chemical reaction:



A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO<sub>x</sub> decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670°F, the oxidation of ammonia begins to become significant. At low temperatures, the formation of ammonium bisulfate causes scaling and corrosion problems.

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.

Ammonia slip from the SCR system is usually less than 3 to 5 ppm. The emission of ammonia increases during load changes due to the instability of the temperature in the catalyst bed as well as at low loads because of the low gas temperature.

Regenerative Selective Catalytic Reduction (R-SCR) applies the Selective Catalytic Reduction (SCR) control process as described below with a preheat process step to reheat the flue gas stream up to SCR catalyst operating temperatures. The preheating process combines use of a thermal heat sink (packed bed) and a duct burner. The thermal sink recovers heat from the hot gas leaving the R-SCR and then transfers that heat to gas entering the R-SCR. The duct burner is used to complete the preheating process. R-SCR operates with several packed bed/SCR reactor vessels. Gas flow alternates between vessels. Each of the vessels alternates between preheating/treating and heat recovery.

The benefits of R-SCR are:

- Its high energy efficiency allows it to be used after SO<sub>2</sub> and particulate controls.
- R-SCR has a thermal efficiency of 90% - 95% vs. standard heat exchangers which have a thermal efficiency of 60% to 70%.
- Application of R-SCR after SO<sub>2</sub> and PM controls significantly reduces the potential for problems associated with plugging and catalyst poisoning and deactivation.

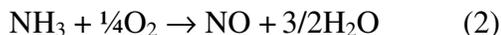
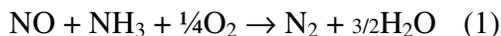
To date, R-SCR has been applied to wood-fired utility boilers. Application of this technology has not been applied to liquid and natural gas fired taconite dryers. Using R-SCR would require research, test runs, and extended trials to identify potential issues related to catalyst selection, and impacts on plant systems. It is not reasonable to assume that vendor guarantees of performance would be forthcoming in advance of a demonstration project. The timeline required to perform such a demonstration project would likely be two years to develop and agree on the test plan, obtain permits for the trial, commission the equipment for the test runs, perform the test runs for a reasonable study period, and evaluate and report on the results. The results would not be available within the time window for establishing emission limits to be incorporated in the state implementation plan (SIP) by December 2007.

Recalling U.S. EPA's intention regarding "available" technologies to be considered for BART, as mentioned in Section 2.B, facility owners are not expected to undergo extended trials in order to learn how to apply a control technology to a completely new and significantly different source type. Therefore, R-SCR is not considered to be technically feasible, and will not be analyzed further in this BART analysis.

SCR with reheat through a conventional duct burner (rather than using a regenerative heater) has been successfully implemented more widely and in higher airflow applications and will be carried forward in this analysis as available and applicable technology that is reasonably expected to be technically feasible.

### **Selective Non-Catalytic Reduction (SNCR)**

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N<sub>2</sub>, and water. SNCR control efficiency is typically 25% - 60%. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:



At temperature ranges of 1470 to 1830°F reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate.

Based on the information contained within this report, a SNCR is considered a technically feasible technology for NO<sub>x</sub> reduction for this BART analysis.

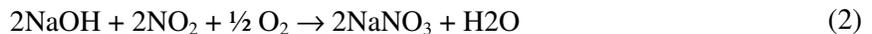
### **Low Temperature Oxidation (LTO)**

The LTO system utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO<sub>x</sub>. In the system, the NO<sub>x</sub> in the flue gas is oxidized to form nitrogen pentoxide (equations 1, 2, and 3). The nitrogen pentoxide forms nitric acid vapor as it contacts the water vapor in the flue gas (4). Then the nitric acid vapor is absorbed as dilute nitric acid and is neutralized by the sodium hydroxide or lime in the scrubbing solution forming sodium nitrate (5) or calcium nitrate. The nitrates are removed from the scrubbing system and discharged to an appropriate water treatment system. Commercially available LTO systems include Tri-NO<sub>x</sub>® and LoTOx®.



### **Low Temperature Oxidation (Tri-NO<sub>x</sub><sup>®</sup>)**

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO<sub>2</sub> in a primary scrubbing stage. Then NO<sub>2</sub> is removed through caustic scrubbing in a secondary stage. The reactions are as follows:



Tri-NO<sub>x</sub><sup>®</sup> is a multi-staged wet scrubbing process in industrial use. Several process columns, each assigned a separate processing stage, are involved. In the first stage, the incoming material is quenched to reduce its temperature. The second, oxidizing stage, converts NO to NO<sub>2</sub>. Subsequent stages reduce NO<sub>2</sub> to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-NO<sub>x</sub><sup>®</sup> is typically applied at small to medium sized sources with high NO<sub>x</sub> concentration in the exhaust gas (1,000 ppm NO<sub>x</sub>).

### **Low Temperature Oxidation (LoTOx<sup>®</sup>)**

BOC Gases' Lo-TOx<sup>®</sup> is an example of a version of an LTO system. LoTOx<sup>®</sup> technology uses ozone to oxidize NO to NO<sub>2</sub> and NO<sub>2</sub> to N<sub>2</sub>O<sub>5</sub> in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N<sub>2</sub>O<sub>5</sub> is converted to HNO<sub>3</sub> in a scrubber, and is removed with lime or caustic. Ozone for LoTOx<sup>®</sup> is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO<sub>x</sub> control. Ozone is generated from pure oxygen. In order for LoTOx<sup>®</sup> to be economically feasible, a source of low cost oxygen must be available from a pipeline or on site generation.

In addition, only two of BOC's LoTOx<sup>®</sup> installations are fully installed and operational applications. Therefore, although this is an emerging technology, the limited application means that it has not been demonstrated to be an effective technology in widespread application. In addition, LoTOx has not been applied on a taconite dryer or similar process. Consequently, the technical feasibility of LTO as technically infeasible for this application and will not be evaluated further.

## Step 2 Conclusion

Based upon the determination within Step 2, the remaining NO<sub>x</sub> control technologies that are available and applicable to the process boilers are identified in Table 5-32. The technical feasibility as determined in Step 2 is also included in Table 5-32.

**Table 5-32 Line 1 Dryer NO<sub>x</sub> Control Technology – Availability, Applicability and Technical Feasibility**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Available?</b>	<b>Applicable?</b>	<b>Technically Feasible?</b>
External Flue Gas Recirculation (EFGR)	Yes	Yes	No
Low-NO <sub>x</sub> Burners	Yes	Yes	Yes
Overfired Air	Yes	Yes	No
Induced Flue Gas Recirculation (IFGR)	Yes	Yes	Yes
Energy Efficiency Projects	Yes	Yes	Project Dependent
Alternative Fuels	Yes	Yes	Yes – Not required by BART
Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	No
Selective Catalytic Reduction (SCR)	Yes	Yes	Yes
Regenerative SCR	Yes	Yes	No
Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes
Low Temperature Oxidation (LTO)	Yes	No	No

## 5.C.ii.cSTEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 5-33 describes the expected control efficiency from each of the remaining technically feasible control options as identified in Step 2.

**Table 5-33 Line 1 Dryer NO<sub>x</sub> Control Technology Effectiveness**

<b>NO<sub>x</sub> Pollution Control Technology</b>	<b>Approximate Control Efficiency</b>
Selective Catalytic Reduction (SCR) with Reheat	80%
Low NOX Burner / Flue Gas Recirculation (LNB/FGR)	75%
Regenerative Selective Catalytic Reduction (R-SCR)	70%
Low NOX Burner / Overfire Air (LNB/OFA)	67%
Low NOX Burner (LNB)	50%
Selective Non-Catalytic Reduction (SNCR)	50%

**5.C.ii.d STEP 4 – Evaluate Impacts and Document the Results**

Table 5-34 details the expected costs associated with installation of NO<sub>x</sub> controls. Capital costs were calculated based on the maximum 24-hour emissions, U.S. EPA cost models, and vendor estimates. Vendor estimates for capital costs based on a specific flow rate were scaled to each stack's flow rate using the six-tenths-factor rule to account for the economy of scale. Operating costs were based on 100% utilization and 7650 operating hours per year, which is extremely conservative. Operating costs were proportionally adjusted to reflect site specific flow rates and pollutant concentrations.

After a tour of the facility and discussions with facility management, it was determined the space surrounding the boilers is congested and the area surrounding the building supports vehicle and rail traffic to transport materials to and from the building. A site-specific estimate for site-work, foundations, and structural steel was added based upon the facility site to arrive at the total retrofit installed cost of the control technology. See Appendix C for a site plan of the facility. Additionally, the structural design of the existing building would not support additional equipment on the roof. The detailed cost analysis is provided in Appendix A.

**Table 5-34 Line 1 Dryer NO<sub>x</sub> Control Cost Summary**

<b>Control Technology</b>	<b>Installed Capital Cost (\$)</b>	<b>Total Annual Cost (\$/yr)</b>	<b>Annualized Pollution Control Cost (\$/ton)</b>	<b>Incremental Control Cost (\$/ton)</b>
SCR with Reheat	\$6,439,029	\$1,008,211	\$83,472	NA
LNB/FGR	\$1,087,058	\$134,645	\$11,891	\$19,493
R-SCR	\$5,445,064	\$1,024,459	\$96,934	NA
LNB/OFA	\$888,317	\$116,686	\$11,535	\$21,669
LNB	\$432,579	\$61,070	\$8,090	Lowest
SNCR	\$915,968	\$278,929	\$36,949	NA

Based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like Clean Air Interstate Rule (CAIR), cost-effective air pollution controls in the electric utility industry for large power plants are in the range \$1,000 to \$1,300 per ton removed as illustrated in Appendix E. This cost-effective threshold is also an indirect measure of affordability for the electric utility industry used by USEPA to support the BART rule-making process. For the purpose of this taconite BART analysis, the \$1,000 to \$1,300 cost effectiveness threshold is used as the cutoff in proposing BART. The taconite industry is not afforded the same market stability or guaranteed cost recovery mechanisms that are afforded to the electric utility industry. Therefore, the \$1,000 to \$1,300 per ton removed is considered a greater business risk to the taconite industry. Thus it is reasonable to use it as a cost effective threshold for proposing BART in lieu of developing industry and site specific data.

The annualized pollution control cost value was used to determine whether or not additional impacts analyses would be conducted for the technology. If the control cost was less than a screening threshold established by MDEQ, then visibility modeling impacts, and energy and other impacts are evaluated. MDEQ set the screening level to eliminate technologies from requiring the additional impact analyses at an annualized cost of \$12,000 per ton of controlled pollutant<sup>46</sup>. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts.

The incremental control cost listed in Table 5-34 represents the incremental value of each technology as compared to the technology with the next highest level of control. The cost of control and

<sup>46</sup> Michigan Department of Environmental Quality May 12, 2006 meeting.

incremental cost of SCR with reheat, R-SCR and SNCR are not reasonable. The magnitude of the capital and operating costs of remaining alternatives is also significant and may impact the viability of continued operation.

**Energy and Environmental Impacts**

The energy and non-air quality impacts for LNB and LNB with IFGR are presented in Table 5-35. Because the cost of the remaining NO<sub>x</sub> control technologies for the Line 1 Dryer is so high and does not meet a reasonable definition of cost effective technology, these technologies are removed from further consideration in this analysis.

**Table 5-35 Line 1 Dryer NO<sub>x</sub> Control Technology – Other Impacts Assessment**

Control Option	Energy Impacts	Other Impacts
LNB	- Minimal energy impacts	<ul style="list-style-type: none"> <li>- Increase in CO emissions</li> <li>- Potential for steam tube wastage due to longer combustion flame</li> </ul>
LNB/FGR	- Minimal energy impacts.	<ul style="list-style-type: none"> <li>- Increase in CO emissions</li> <li>- Potential for steam tube wastage due to longer combustion flame.</li> </ul>

**5.C.ii.eSTEP 5 – Evaluate Visibility Impacts**

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality impacts, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. This section of the report evaluates the visibility impacts of BART NO<sub>x</sub> control and the resulting degree of visibility improvement.

**Predicted 24-Hour Maximum Emission Rates**

Consistent with the use of the highest daily emissions for baseline, or pre-BART, visibility impacts, the post-BART emissions to be used for the visibility impacts analysis should also reflect a maximum 24-hour average project emission rate. In the visibility impacts NO<sub>x</sub> modeling analysis, the emissions from the sources undergoing a full BART NO<sub>x</sub> analysis were adjusted to reflect the projected 24-hour maximum NO<sub>x</sub> emission rate when applying the control technologies that met the threshold requirements of steps 1 – 4. The emissions from all other Subject-to-BART sources were not changed. Table 5-36 provides a summary of the modeled 24-hour maximum emission rates and

their computational basis for the evaluated NO<sub>x</sub> control technologies. Table 5-37 provides a summary of the modeling input data.

### **Post-BART Visibility Impacts Modeling Results**

Results of the post-BART visibility impacts modeling for NO<sub>x</sub> for the process boilers are presented in Table 5-38. The results summarize 98th percentile dV value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas. The comparison of the post-BART modeling scenarios to the baseline conditions is presented in Table 5-39.

Visibility impacts with SO<sub>2</sub> controls are presented in section 6.

**Table 5-36 Line 1 Dryer Post-BART Modeling Scenarios**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
1	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
3	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
4	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
5	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
6	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
			Natural Gas					
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
7	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
8	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
9	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
10	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
12	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
13	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
14	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
15	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
16	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
17	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1	Low Sulfur Fuel	LNB w/OFA	0.0%	0.1	67.0%	6.4

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
		EUBOILER2	Oil Natural Gas					
18	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
19	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
20	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
21	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
22	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
			Natural Gas					
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
24	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
25	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
26	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
27	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
28	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
29	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
30	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
31	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

**Table 5-37 Line 1 Dryer Post-BART NO<sub>x</sub> Modeling Scenarios - Modeling Input Data**

Control Scenario	SV #	Emission Unit	Stack Easting (utm)	Stack Northing (utm)	Height of Opening from Ground (ft)	Base Elevation of Ground (ft)	Stack length, width, or Diameter (ft)	Flow Rate at exit (acfm)	Exit Temp (°F)
All Scenarios	SVP0051981 SVP0051711	EUKILN1	46.44084994	-87.653 40738	240	1474	19.3	842,000	300
			46.44075383	-87.651 32336	160		13.5	306,000	300
	SVP0082951	EUDRYER1	46.44075383	-87.651 32336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.654 12418	130	1474	7.5	192,000	350

**Table 5-38 Line 1 Dryer Post-BART NO<sub>x</sub> Modeling Scenarios - Visibility Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
1	IRNP	0.323	2.0	0.275	1.000	0.228	1.000	0.248	2
2	IRNP	0.610	15.0	0.620	10.000	0.535	8.000	0.600	33
3	IRNP	0.183	0.0	0.177	0.000	0.154	0.000	0.173	0
4	IRNP	0.717	19.0	0.717	11.000	0.589	12.000	0.668	42
5	IRNP	0.322	2.0	0.256	0.000	0.219	1.000	0.254	2
6	IRNP	0.619	15.0	0.623	10.000	0.528	8.000	0.598	33
7	IRNP	0.182	0.0	0.177	0.000	0.155	0.000	0.169	0
8	IRNP	0.714	19.0	0.711	11.000	0.583	11.000	0.653	41
9	IRNP	0.314	2.0	0.252	0.000	0.213	1.000	0.248	2
10	IRNP	0.618	15.0	0.607	10.000	0.527	8.000	0.590	33
11	IRNP	0.176	0.0	0.168	0.000	0.150	0.000	0.161	0
12	IRNP	0.719	19.0	0.693	10.000	0.592	9.000	0.654	38
13	IRNP	0.315	2.0	0.246	0.000	0.218	1.000	0.243	2
14	IRNP	0.627	15.0	0.608	9.000	0.544	8.000	0.585	32
15	IRNP	0.176	0.0	0.171	0.000	0.150	0.000	0.160	0
16	IRNP	0.722	19.0	0.673	10.000	0.605	9.000	0.656	38
17	IRNP	0.326	2.0	0.243	0.000	0.218	1.000	0.243	2
18	IRNP	0.626	15.0	0.605	9.000	0.542	8.000	0.596	32
19	IRNP	0.175	0.0	0.173	0.000	0.151	0.000	0.163	0
20	IRNP	0.734	19.0	0.692	10.000	0.605	10.000	0.654	39
21	IRNP	0.324	2.0	0.241	0.000	0.215	1.000	0.241	2
22	IRNP	0.625	15.0	0.602	9.000	0.291	3.000	0.588	27
23	IRNP	0.175	0.0	0.170	0.000	0.150	0.000	0.165	0
24	IRNP	0.727	19.0	0.689	10.000	0.603	10.000	0.656	39
25	IRNP	0.326	2.0	0.245	0.000	0.207	1.000	0.241	2
26	IRNP	0.623	15.0	0.605	9.000	0.550	8.000	0.597	32
27	IRNP	0.176	0.0	0.172	0.000	0.151	0.000	0.165	0
28	IRNP	0.704	19.0	0.672	10.000	0.606	9.000	0.657	38
29	IRNP	0.325	2.0	0.239	0.000	0.198	1.000	0.240	2
30	IRNP	0.613	14.0	0.614	9.000	0.542	8.000	0.588	31
31	IRNP	0.173	0.0	0.172	0.000	0.151	0.000	0.164	0

**Table 5-39 Line 1 Dryer Post-BART NO<sub>x</sub> Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV
1	IRNP	0.391	17	0.447	10	0.371	10	0.426	39
2	IRNP	0.104	4	0.102	1	0.064	3	0.074	8
3	IRNP	0.531	19	0.545	11	0.445	11	0.501	41
4	IRNP	-0.003	0	0.005	0	0.01	-1	0.006	-1
5	IRNP	0.392	17	0.466	11	0.38	10	0.42	39
6	IRNP	0.095	4	0.099	1	0.071	3	0.076	8
7	IRNP	0.532	19	0.545	11	0.444	11	0.505	41
8	IRNP	0	0	0.011	0	0.016	0	0.021	0
9	IRNP	0.4	17	0.47	11	0.386	10	0.426	39
10	IRNP	0.096	4	0.115	1	0.072	3	0.084	8
11	IRNP	0.538	19	0.554	11	0.449	11	0.513	41
12	IRNP	-0.005	0	0.029	1	0.007	2	0.02	3
13	IRNP	0.399	17	0.476	11	0.381	10	0.431	39
14	IRNP	0.087	4	0.114	2	0.055	3	0.089	9
15	IRNP	0.538	19	0.551	11	0.449	11	0.514	41
16	IRNP	-0.008	0	0.049	1	-0.006	2	0.018	3
17	IRNP	0.388	17	0.479	11	0.381	10	0.431	39
18	IRNP	0.088	4	0.117	2	0.057	3	0.078	9
19	IRNP	0.539	19	0.549	11	0.448	11	0.511	41
20	IRNP	-0.02	0	0.03	1	-0.006	1	0.02	2
21	IRNP	0.39	17	0.481	11	0.384	10	0.433	39
22	IRNP	0.089	4	0.12	2	0.308	8	0.086	14
23	IRNP	0.539	19	0.552	11	0.449	11	0.509	41
24	IRNP	-0.013	0	0.033	1	-0.004	1	0.018	2
25	IRNP	0.388	17	0.477	11	0.392	10	0.433	39
26	IRNP	0.091	4	0.117	2	0.049	3	0.077	9
27	IRNP	0.538	19	0.55	11	0.448	11	0.509	41
28	IRNP	0.01	0	0.05	1	-0.007	2	0.017	3
29	IRNP	0.389	17	0.483	11	0.401	10	0.434	39
30	IRNP	0.101	5	0.108	2	0.057	3	0.086	10
31	IRNP	0.541	19	0.55	11	0.448	11	0.51	41

## 6. Visibility Impacts

---

As previously stated in section 4 of this document, states are required to consider the degree of visibility improvement resulting from the retrofit technology, in combination with other factors such as economic, energy and other non-air quality, when determining BART for an individual source. The baseline, or pre-BART, visibility impacts modeling was presented in section 4 of this document. The visibility impacts of individual control technologies were presented in Step 5 of section 5 of this document. This section of the report evaluates the various BART control scenarios utilizing both SO<sub>2</sub> and NO<sub>x</sub> controls, and estimates the resulting degree of visibility improvement.

### 6.A Post-Control Modeling Scenarios

Steps 1-4 of the BART analysis identified the control technologies that were:

- Available and applicable;
- Technically feasible; and
- Below the screening cost threshold for further BART analysis.

Step 5 of the BART analysis evaluated the visibility impacts of each of the control technologies that met the requirements of the screening analysis of steps 1-4.

The interactions between the visibility impairing pollutants NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>10</sub> can play a large part in predicting impairment. It is therefore important to take a multi-pollutant approach when assessing visibility impacts. Accordingly, this visibility improvement analysis evaluates several operating control scenarios that account for the various combinations of available NO<sub>x</sub> controls. In addition, two site-specific scenarios were developed so that the evaluation includes other operating scenarios and conditions that would improve visibility impairment. The post-control modeling scenarios, including those presented in Step 5 of section 5, are presented in Table 6-1. The modeling scenario stack parameters are presented in Table 6-2.

### 6.B Post-Control Modeling Results

Results of the post-control modeling scenarios are presented in Table 6-3. The results summarize 98th percentile dV value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas. The comparison of the post-control modeling

scenarios to the baseline conditions is presented in Table 6-4. Notably, none of the post-control scenarios produces a visibility improvement that exceeds the perceptible threshold of 1-2 dV.

Additionally, Table 6-5 illustrates the scenarios on a \$/dV basis. The dollar per deciview ranges from \$6.1 million to more than \$79 million per dV of improvement.

**Table 6-1 Post-Control Modeling Scenarios**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
1	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
2	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
3	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
4	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
5	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
			Natural Gas					
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
6	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
7	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	0.1	0.0%	19.3
8	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
9	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
10	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
12	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
13	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
14	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
15	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR	0.0%	0.1	75.0%	4.8
16	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
17	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
18	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
19	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
20	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
21	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
22	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1	Low Sulfur Fuel	LNB w/OFA	0.0%	0.1	67.0%	6.4

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
		EUBOILER2	Oil Natural Gas					
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA	0.0%	0.1	67.0%	6.4
24	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
25	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
26	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
27	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice	0.0%	8.3	0.0%	3.7
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
28	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	0.0%	200.2 72.8	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB	0.0%	8.3	50.0%	1.8

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO <sub>2</sub>		NO <sub>x</sub>	
			SO <sub>2</sub>	NO <sub>x</sub>	% Reduction	Max 24-hour lbs/hr	% Reduction	Max 24-hour lbs/hr
			Natural Gas					
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
29	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	0.0%	200.2 72.8	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
30	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7
31	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	80% 80%	40.0 14.6	80% 80%	160.2 58.2
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	8.3	50.0%	1.8
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB	0.0%	0.1	50.0%	9.7

**Table 6-2 Post-Control NO<sub>x</sub> Modeling Scenarios - Modeling Input Data**

Control Scenario	SV #	Emission Unit	Stack Easting (utm)	Stack Northing (utm)	Height of Opening from Ground (ft)	Base Elevation of Ground (ft)	Stack length, width, or Diameter (ft)	Flow Rate at exit (acfm)	Exit Temp (°F)
All Scenarios	SVP0051981 SVP0051711	EUKILN1	46.44084994	-87.653 40738	240	1474	19.3	842,000	300
			46.44075383	-87.651 32336	160		13.5	306,000	300
	SVP0082951	EUDRYER1	46.44075383	-87.651 32336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.654 12418	130	1474	7.5	192,000	350

**Table 6-3 Post-Control Modeling Scenarios - Visibility Modeling Results**

Scenario	Modeling Results								
		2002		2003		2004		2002-2004	
	Limiting Class I Area	Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV	Modeled 98%ile ΔV	# days over 0.5 ΔV
Base	IRNP	0.714	19.0	0.722	11.000	0.599	11.000	0.674	41
1	IRNP	0.323	2.0	0.275	1.000	0.228	1.000	0.248	2
2	IRNP	0.610	15.0	0.620	10.000	0.535	8.000	0.600	33
3	IRNP	0.183	0.0	0.177	0.000	0.154	0.000	0.173	0
4	IRNP	0.717	19.0	0.717	11.000	0.589	12.000	0.668	42
5	IRNP	0.322	2.0	0.256	0.000	0.219	1.000	0.254	2
6	IRNP	0.619	15.0	0.623	10.000	0.528	8.000	0.598	33
7	IRNP	0.182	0.0	0.177	0.000	0.155	0.000	0.169	0
8	IRNP	0.714	19.0	0.711	11.000	0.583	11.000	0.653	41
9	IRNP	0.314	2.0	0.252	0.000	0.213	1.000	0.248	2
10	IRNP	0.618	15.0	0.607	10.000	0.527	8.000	0.590	33
11	IRNP	0.176	0.0	0.168	0.000	0.150	0.000	0.161	0
12	IRNP	0.719	19.0	0.693	10.000	0.592	9.000	0.654	38
13	IRNP	0.315	2.0	0.246	0.000	0.218	1.000	0.243	2
14	IRNP	0.627	15.0	0.608	9.000	0.544	8.000	0.585	32
15	IRNP	0.176	0.0	0.171	0.000	0.150	0.000	0.160	0
16	IRNP	0.722	19.0	0.673	10.000	0.605	9.000	0.656	38
17	IRNP	0.326	2.0	0.243	0.000	0.218	1.000	0.243	2
18	IRNP	0.626	15.0	0.605	9.000	0.542	8.000	0.596	32
19	IRNP	0.175	0.0	0.173	0.000	0.151	0.000	0.163	0
20	IRNP	0.734	19.0	0.692	10.000	0.605	10.000	0.654	39
21	IRNP	0.324	2.0	0.241	0.000	0.215	1.000	0.241	2
22	IRNP	0.625	15.0	0.602	9.000	0.291	3.000	0.588	27
23	IRNP	0.175	0.0	0.170	0.000	0.150	0.000	0.165	0
24	IRNP	0.727	19.0	0.689	10.000	0.603	10.000	0.656	39
25	IRNP	0.326	2.0	0.245	0.000	0.207	1.000	0.241	2
26	IRNP	0.623	15.0	0.605	9.000	0.550	8.000	0.597	32
27	IRNP	0.176	0.0	0.172	0.000	0.151	0.000	0.165	0
28	IRNP	0.704	19.0	0.672	10.000	0.606	9.000	0.657	38
29	IRNP	0.325	2.0	0.239	0.000	0.198	1.000	0.240	2
30	IRNP	0.613	14.0	0.614	9.000	0.542	8.000	0.588	31
31	IRNP	0.173	0.0	0.172	0.000	0.151	0.000	0.164	0

**Table 6-4 Post-Control Modeling Scenarios – Improved Visibility Modeling Results**

Scenario	Modeling Results								
	Limiting Class I Area	2002		2003		2004		2002-2004	
		Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	Decreased No. of Days exceeding 0.5 dV
1	IRNP	0.391	17	0.447	10	0.371	10	0.426	39
2	IRNP	0.104	4	0.102	1	0.064	3	0.074	8
3	IRNP	0.531	19	0.545	11	0.445	11	0.501	41
4	IRNP	-0.003	0	0.005	0	0.01	-1	0.006	-1
5	IRNP	0.392	17	0.466	11	0.38	10	0.42	39
6	IRNP	0.095	4	0.099	1	0.071	3	0.076	8
7	IRNP	0.532	19	0.545	11	0.444	11	0.505	41
8	IRNP	0	0	0.011	0	0.016	0	0.021	0
9	IRNP	0.4	17	0.47	11	0.386	10	0.426	39
10	IRNP	0.096	4	0.115	1	0.072	3	0.084	8
11	IRNP	0.538	19	0.554	11	0.449	11	0.513	41
12	IRNP	-0.005	0	0.029	1	0.007	2	0.02	3
13	IRNP	0.399	17	0.476	11	0.381	10	0.431	39
14	IRNP	0.087	4	0.114	2	0.055	3	0.089	9
15	IRNP	0.538	19	0.551	11	0.449	11	0.514	41
16	IRNP	-0.008	0	0.049	1	-0.006	2	0.018	3
17	IRNP	0.388	17	0.479	11	0.381	10	0.431	39
18	IRNP	0.088	4	0.117	2	0.057	3	0.078	9
19	IRNP	0.539	19	0.549	11	0.448	11	0.511	41
20	IRNP	-0.02	0	0.03	1	-0.006	1	0.02	2
21	IRNP	0.39	17	0.481	11	0.384	10	0.433	39
22	IRNP	0.089	4	0.12	2	0.308	8	0.086	14
23	IRNP	0.539	19	0.552	11	0.449	11	0.509	41
24	IRNP	-0.013	0	0.033	1	-0.004	1	0.018	2
25	IRNP	0.388	17	0.477	11	0.392	10	0.433	39
26	IRNP	0.091	4	0.117	2	0.049	3	0.077	9
27	IRNP	0.538	19	0.55	11	0.448	11	0.509	41
28	IRNP	0.01	0	0.05	1	-0.007	2	0.017	3
29	IRNP	0.389	17	0.483	11	0.401	10	0.434	39
30	IRNP	0.101	5	0.108	2	0.057	3	0.086	10
31	IRNP	0.541	19	0.55	11	0.448	11	0.51	41

**Table 6-5 Post-Control Modeling Results – Dollars per Deciview Improvement**

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value (Δ-dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
Base	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice			
Base	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
Base	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
1	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,055,581	0.447	\$69,475,573
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
2	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,048,540	0.104	\$58,159,038
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
3	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,104,122	0.545	\$68,080,958
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
4	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal	Good Combustion Practice	\$61,070	0.01	\$6,107,000

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
			Natural Gas				
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
5	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,165,192	0.466	\$79,753,630
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
6	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,048,540	0.099	\$61,493,020
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
7	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,104,121	0.545	\$68,153,011
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
8	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$303,758	0.016	\$18,984,875
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
9	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,055,581	0.47	\$66,652,096
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
10	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,352,298	0.115	\$55,237,373
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
11	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,407,880	0.554	\$67,523,250
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
12	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$364,828	0.029	\$12,580,275
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
13	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,420,409	0.476	\$66,009,262
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
14	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,413,368	0.114	\$56,257,614
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
15	SVP0051981	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,165,192	0.551	\$67,450,439

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
	SVP0051711						
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/FGR			
16	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$390,751	0.049	\$7,974,510
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
17	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,446,333	0.479	\$65,649,965
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
18	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,439,291	0.117	\$55,036,675
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
19	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,494,873	0.549	\$68,296,672
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
20	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$451,821	0.03	\$15,060,700
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB			

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
			Natural Gas				
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
21	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,507,403	0.481	\$65,503,956
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
22	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,500,362	0.12	\$54,169,683
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
23	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,555,942	0.552	\$68,036,127
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB w/OFA			
24	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$286,968	0.033	\$8,696,000
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
25	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,391,089	0.477	\$78,388,027
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
26	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,335,508	0.117	\$54,149,641
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
27	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,391,089	0.55	\$67,983,798
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	Good Combustion Practice			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
28	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	Good Combustion Practice	\$348,038	0.05	\$6,960,760
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
29	SVP0051981 SVP0051711	EUKILN1	Low Sulfur Coal Natural Gas	SCR w/reheat	\$31,403,619	0.483	\$65,017,845
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
30	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	\$6,396,578	0.108	\$59,227,574
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil Natural Gas	LNB			
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			
31	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	SCR w/reheat	\$37,452,159	0.55	\$68,094,834
	SVP0082951	EUDRYER1	Low Sulfur Fuel Oil	LNB			

Control Scenario	SV #	Emission Unit	Scenario Control Technology		Annualized Cost (\$/yr)	Improved Modeled 98 <sup>th</sup> Percentile Value ( $\Delta$ -dV)	\$/dV
			SO <sub>2</sub>	NO <sub>x</sub>			
			Natural Gas				
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	Low Sulfur Fuel Oil Natural Gas	LNB			

## 7. Select BART

---

### DRAFT LANGUAGE

BART for Tilden is determined to be as described below.

#### Line 1 Indurating Furnace

For SO<sub>2</sub>, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO<sub>2</sub> emissions limit is 28,000 lb per day for Line 1 when coal is burned.

For NO<sub>x</sub>, the reduction due to good combustion practices on Line 1 is selected as BART. Other add-on controls for NO<sub>x</sub> are not cost effective. The corresponding NO<sub>x</sub> limit is specified in Appendix 2 Schedule of Compliance in the Renewable Operating Permit 199600379 and with Rule 336.1801.

For PM, requirements compelled by the October 30, 2006 MACT standard constitute BART. The corresponding emissions limits are equivalent to the limits identified in Table 3-1.

#### Process Boilers 1 and 2

For SO<sub>2</sub>, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO<sub>2</sub> emissions limit is regulated by limiting the sulfur content to 1.2% by weight, calculated on the basis on 18,000 BTU per pound when used oil is burned.

For NO<sub>x</sub>, the reduction due to good combustion practices is selected as BART. Other add-on controls for NO<sub>x</sub> are not cost effective.

For PM, requirements compelled by the September 13, 2007 MACT standard constitute BART. The corresponding emissions limits are equivalent to the limits identified in Table 3-1.

#### Line 1 Dryer

For SO<sub>2</sub>, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO<sub>2</sub> emissions limit is regulated by limiting the sulfur content to 1.5% by weight, calculated on the basis on 18,000 BTU per pound when used oil is burned.

For NO<sub>x</sub>, the reduction due to good combustion practices is selected as BART. Other add-on controls for NO<sub>x</sub> are not cost effective.

For PM, requirements compelled by the October 30, 2006 MACT standard constitute BART. The corresponding emissions limits are equivalent to the limits identified in Table 3-1.

The schedule for implementation of controls is by October 30, 2006, well in advance of the 5-year time-frame required for BART implementation.

**Michigan Operations - West (Tilden)**  
**BART Report - Attachment A: Emission Control Cost Analysis**  
**Table A.1: Grate Kiln Cost Summary**

12/28/2006

**NO<sub>x</sub> Control Cost Summary**

Control Technology	Control Eff %	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost \$	Annualized Cost \$/yr	Pollution Control Cost \$/ton	Incremental Control Cost \$/ton
Selective Catalytic Reduction with Reheat	80%	923	3690	\$65,492,092	\$31,055,581	\$8,416	n/a

**SO<sub>2</sub> Control Cost Summary**

Control Technology	Control Eff %	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost \$	Annualized Cost \$/yr	Pollution Control Cost \$/ton	Incremental Control Cost \$/ton
Spray Dry Baghouse	90%	115.3	1037.8	\$167,260,397	\$23,254,882	\$22,407	n/a
Wet Scrubber (Absorber) (after existing ESP)	80%	230.6	922.5	\$34,869,327	\$6,048,540	\$6,557	n/a
Secondary Wet Walled Electrostatic Precipitator (WWESP) (after existing ESP)	80%	230.6	922.5	\$52,638,755	\$13,922,184	\$15,091	n/a
DSI Baghouse	55%	518.9	634.2	\$42,082,032	\$9,975,786	\$15,729	n/a

## BART Report - Attachment A: Emission Control Cost Analysis

Table A.1: Process Boilers 1 and 2 and Line 1 Dryer Cost Summary

NO<sub>x</sub> Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost \$	Annualized Cost \$/yr	Pollution Control Cost \$/ton	Incremental Cost
<b>Selective Catalytic Reduction (SCR) with Reheat</b>							
Process Boilers #1 and #2	80%	15.85	63.38	\$6,317,686	\$2,528,225	\$39,888	n/a
Line 1 Dryer	80%	3.02	12.08	\$6,439,029	\$1,008,211	\$83,472	n/a
<b>Low NO<sub>x</sub> Burner / Flue Gas Recirculation</b>							
Process Boilers #1 and #2	75%	19.81	59.42	\$2,190,300	\$303,758	\$5,112	n/a
Line 1 Dryer	75%	3.77	11.32	\$1,087,058	\$134,645	\$11,891	\$19,493
<b>Regenerative Selective Catalytic Reduction (R-SCR)</b>							
Process Boilers #1 and #2	70%	23.77	55.46	\$16,117,290	\$3,303,391	\$59,563	n/a
Line 1 Dryer	70%	4.53	10.57	\$5,445,064	\$1,024,459	\$96,934	n/a
<b>Low NO<sub>x</sub> Burner / Overfire Air (OFA)</b>							
Process Boilers #1 and #2	67%	26.15	53.08	\$3,031,714	\$390,751	\$7,361	na
Line 1 Dryer	67%	4.98	10.12	\$888,317	\$116,686	\$11,535	\$21,669
<b>Low NO<sub>x</sub> Burner</b>							
Process Boilers #1 and #2	50%	39.61	39.61	\$1,320,909	\$286,968	\$7,244	n/a
Line 1 Dryer	50%	7.55	7.55	\$432,579	\$61,070	\$8,090	n/a
<b>Selective Non-Catalytic Reduction (SNCR)</b>							
Process Boilers #1 and #2	50%	39.61	39.61	\$1,501,420	\$468,772	\$11,833	n/a
Line 1 Dryer	50%	7.55	7.55	\$915,968	\$278,929	\$36,949	n/a

SO<sub>2</sub> Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost \$	Annualized Cost \$/yr	Pollution Control Cost \$/ton	Incremental Cost
<b>Spray Dry Baghouse</b>							
Process Boilers #1 and #2	90%	0.03	0.23	\$56,323,180	\$8,640,697	\$38,403,097	n/a
Line 1 Dryer	90%	0.03	0.23	\$26,617,360	\$4,025,029	\$17,889,019	n/a
<b>Wet Scrubber</b>							
Process Boilers #1 and #2	80%	0.05	0.20	\$9,309,297	\$1,489,576	\$7,447,882	n/a
Line 1 Dryer	80%	6.81	27.26	\$3,898,490	\$684,207	\$25,103	n/a
<b>Wet ESP (WWESP)</b>							
Process Boilers #1 and #2	80%	0.05	0.20	\$17,123,526	\$3,146,592	\$15,732,959	n/a
Line 1 Dryer	80%	6.81	27.26	\$7,674,618	\$1,429,065	\$52,432	n/a
<b>DSI Baghouse</b>							
Process Boilers #1 and #2	55%	0.11	0.14	\$32,010,048	\$4,892,432	\$35,581,325	n/a
Line 1 Dryer	55%	0.04	0.14	\$26,023,184	\$4,079,117	\$29,666,302	n/a

**Michigan Operations - West (Tilden)**  
**BART Report - Changes to MDEQ BART Modeling Protocol**  
**Appendix B**

<b>CALMET</b>				
Variable	Description	Value	Default	Comments
<b>Input Group 2</b>				
NX	Number of X grid cells	66	n/a	
NY	Number of Y grid cells	39	n/a	
XORIGKM	Reference point coordinates for grid	180	n/a	
YORIGKM	Reference point coordinates for grid	612	n/a	
<b>Input Group 4</b>				
NOOBS	No Observation Mode	0	Y	Include Surface, Upper Air and Precipitation Observations
NSSTA	Number of Surface Stations	88	n/a	88 surface weather stations
NPSTA	Number of Precipitation Stations	99	n/a	99 precipitation stations
<b>Input Group 5</b>				
BIAS	Surface/upper-air weighting factors	-1, 11*0	12*0	Surface Layer is set to -1 since IEXTRP=-1
<b>Input Group 6</b>				
ITPROG	3D temperature from observations or from prognostic data?	0	Y	Inclusion of Surface and Upper Air
<b>CALPUFF</b>				
Variable	Description	Value	Default	Comments
<b>Input Group 4</b>				
NX	Number of X grid cells in met grid	66	n/a	
NY	Number of Y grid cells in met grid	39	n/a	
XORIGKM	Reference point coordinates for met grid	180	n/a	
YORIGKM	Reference point coordinates for met grid	612	n/a	
IBCOMP	X index of LL corner	1	n/a	
JBCOMP	Y index of LL corner	1	n/a	
IECOMP	X index of UR corner	66	n/a	
JECOMP	Y index of UR corner	39	n/a	

**Cleveland Cliffs Michigan Operations - Taconite BART Analysis  
SO<sub>2</sub> Control  
Indurating Furnaces**

**Available and Applicable Review**

Revised: December 1, 2006

		Step 1	Step 2					
		This table is part of the CCMO Taconite BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.						
Reference No. <sup>1</sup>	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Is this a generally available control technology?	Is the control technology available to indurating furnaces?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?	Approximate Control Efficiency	Comments	Basic Principle
1	Wet Scrubbing (High Efficiency)	Y	Y	Y	Y	90-95%		Absorption and reaction using an alkaline reagent to produce a solid compound
2	Wet Scrubbing (Low Efficiency)	Y	Y	Y	Y	<50%		Absorption and reaction using an alkaline reagent to produce a solid compound
3	Wet Walled Electrostatic Precipitator (WWESP)	Y	Y	Y	Y	80%		Suspended particles are separated from the flue gas stream, attracted to plates, and collected in hoppers
4	Dry sorbent injection	Y	Y	Y	Y	<55%		Pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO <sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter
5	Spray Dryer Absorption (SDA)	Y	Y	Y	Y	<90%		Lime slurry is sprayed into an absorption tower where SO <sub>2</sub> is absorbed by the slurry, forming CaSO <sub>3</sub> /CaSO <sub>4</sub>
6	Alternative Fuels	Y	Y	Y (for furnaces capable of multiple fuels)	Y (not required by BART)	Site-specific	Natural gas is base case	Use a fuel with lower sulfur content.
7	Load Reduction	N	---	---	---	---	Power plant technology	This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
8	Energy Efficiency Projects	Y	Y	Y (for large projects like heat-recoup)	Y (for large projects like heat-recoup)	Site-specific		decrease amount of fuel required to make an acceptable product
9	Coal Processing	Y	N	---	---	---	Applies only to facilities that burn coal	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
10	Bio Filters	N	---	---	---	---	Research level	Gas stream passes through a packed bed of specially engineered biomedium which supports the growth of active bacterial species. The pollutants in the gas stream are biodegraded or biotransformed into innocuous products, such as carbon dioxide, water, chlor
11	CANSOLV Regenerable SO <sub>2</sub>	N	---	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO <sub>2</sub> from the feed gas in a countercurrent absorption tower. The rich solvent is regenerated by steam stripping, giving a byproduct of pure, water saturated SO <sub>2</sub> gas and lean solvent for recycling to the a
12	Pahlman Process	N	---	---	---	---	Research level	Gas stream is passed through a filter baghouse in which specially-developed, small particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.

**Cleveland Cliffs Michigan Operations - Taconite BART Analysis  
SO<sub>2</sub> Control  
Indurating Furnaces**

**Available and Applicable Review**

**Revised: December 1, 2006**

This table is part of the CCMO Taconite BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No. <sup>1</sup>	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Approximate Control Efficiency	Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to indurating furnaces?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?			
13	SO <sub>x</sub> -NO <sub>x</sub> -Rox-Box	N	---	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SO <sub>x</sub> and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NO <sub>x</sub> emissions.
14	Electron (E-Beam) Process	N	---	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.
15	Electrocatalytic Oxidation	N	---	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NO <sub>x</sub> , and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.
16	NOXSO	N	---	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NO <sub>x</sub> from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NO <sub>x</sub>
17	Copper-Oxide	N	---	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitr
18	SNOX	N	---	---	---	---	Early commercial development stage	Catalytic reduction of NO <sub>x</sub> in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a
19	Cold Plasma	N	---	---	---	---	Research level	

- 1) This number is for reference only. It does not in any way rank the control technologies.  
 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.  
 2) b) US EPA Basic Concepts in Environmental Science, Module 6. <http://www.epa.gov/eogapt1/module6/index.htm>  
 2) c) New and Emerging Environmental Technologies, <http://neet.rti.org/>  
 2) d) ND BART Reports

**Cleveland Cliffs Michigan Operations BART Analysis  
SO<sub>2</sub> Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

Reference No. <sup>1</sup>	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
1	Wet Scrubbing (High Efficiency)	Yes	Yes	Yes	Yes		Absorption and reaction using an alkaline reagent to produce a solid compound
2	Wet Scrubbing (Low Efficiency)	Yes	Yes	Yes	Yes		Absorption and reaction using an alkaline reagent to produce a solid compound
3	Wet Walled Electrostatic Precipitator (WWESP)	Yes	Yes	Yes	Yes	Existing fabric filter control	Suspended particles are separated from the flue gas stream, attracted to plates, and collected in hoppers
4	Dry sorbent injection	Yes	Yes	Yes	Yes		Pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO <sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter
5	Spray Dryer Absorption (SDA)	Yes	Yes	Yes	Yes		Lime slurry is sprayed into an absorption tower where SO <sub>2</sub> is absorbed by the slurry, forming CaSO <sub>3</sub> /CaSO <sub>4</sub>
6	Alternative Fuels	Yes	Yes	Yes	Yes (not required by BART)	Not permitted for other fuels.	Use a fuel with lower sulfur content.
7	Load Reduction	Yes	Yes	No	---	Could reduce production	This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
8	Energy Efficiency Projects	Yes	Yes	Yes	Yes		Decrease amount of fuel required to make an acceptable product
9	Coal Drying	Yes	Yes	No	---	Requires available excess heat source	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
10	Bio Filters	No	---	---	---	Research level	Gas stream passes through a packed bed of specially engineered biomedica which supports the growth of active bacterial species. The pollutants in the gas stream are biodegraded or biotransformed into innocuous products, such as carbon dioxide, water, chloride ion in water, sulfate or nitrate ions in water.
11	CANSOLV Regenerable SO <sub>2</sub>	No	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO <sub>2</sub> from the feed gas in a countercurrent absorption tower. The rich solvent is regenerated by steam stripping, giving a byproduct of pure, water saturated SO <sub>2</sub> gas and lean solvent for recycling to the absorber.
12	Pahlman Process	No	---	---	---	Research level	Gas stream is passed through a filter baghouse in which specially-developed, small-particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.

**Cleveland Cliffs Michigan Operations BART Analysis  
SO2 Control  
Process Boilers**

Available and Applicable Review

DRAFT

Revised: December 1, 2006

Reference No. <sup>1</sup>	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
13	SOx-NOx-Rox-Box	No	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SOx and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NOx emissions.
14	Electron (E-Beam) Process	No	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.
15	Electrocatalytic Oxidation	No	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NOx, and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.
16	NOXSO	No	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NOx is converted to nitrogen and oxygen.
17	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitric oxides in the flue gas. In the regeneration step, the copper sulfate is reduced in a regenerator with a reducing agent, such as natural gas, producing a concentrated stream of SO <sub>2</sub> .
18	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a concentrated liquid sulfuric acid (H <sub>2</sub> SO <sub>4</sub> ).
19	Cold Plasma	No	---	---	---	Research level	

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

1) This number is for reference only. It does not in any way rank the control technologies.

**Cleveland Cliffs Michigan Operations BART Analysis  
SO2 Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

Reference No. <sup>1</sup>	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
<p align="center">This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.</p>							

- 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.
- b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/eogapti1/module6/index.htm>
- c) New and Emerging Environmental Technologies, <http://neet.rti.org/>
- d) ND BART Reports

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>1</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
<b>Combustion Controls</b>							
1	Overfire Air (OFA)	Yes	Yes	Yes	Yes		Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N <sub>2</sub> rather than NO <sub>x</sub>
2	External Flue Gas Recirculation (EFGR)	Yes	Yes	Yes	No		Mixes flue gas with combustion air which reduces oxygen content and therefore reduces flame temperature
3	Low-NO <sub>x</sub> Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NO <sub>x</sub> formation through restriction of oxygen, flame temperature, and/or residence time
4	Induced Flue Gas Recirculation Burners	Yes	Yes	Yes	Yes	Need to be upfired. Need convective loop to get gas recirculated	Draws flue gas to dilute the fuel in order to reduce the flame temperature
5	Low Excess Air	Yes	Yes	Yes	Yes	Reduces production	Reduces oxygen content in flue gas and reduces flame temperature
6	Burners out of Service (BOOS)	Yes	Yes	Yes	No	Need capacity of all burners for worst case scenario	Shut off the fuel flow from one burner or more to create fuel rich and fuel lean zones
7	Fuel Biasing	Yes	Yes	Yes	No		Combustion is staged by diverting fuel from the upper level burners to the lower ones or from the center to the side burners to create fuel-rich and fuel-lean zones
8	Reburning	Yes	Yes	Yes	No		Part of the total fuel heat input is injected into the furnace in a region above the primary (main burners) flames to create a reducing atmosphere (re-burn zone), where hydrocarbon radicals react with NO <sub>x</sub> to produce elemental nitrogen
9	Load Reduction	Yes	Yes	No	---		This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
10	Energy Efficiency Projects	Yes	Yes	Yes	Yes		Decrease amount of fuel required to make an acceptable product
11	Coal Drying	Yes	Yes	No	---	Requires available excess heat.	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
14	Combustion Zone Cooling	Yes	Yes	No	---	Could reduce load capabilities	Cooling of the primary flame zone by heat transfer to surrounding surfaces

**Cleveland Cliffs Michigan Operations BART Analysis**  
**NOx Control**  
**Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
15	Alternate Fuels	Yes	Yes	Yes	Yes (not required by BART)	Requires case by case analysis. Typically, facilities experience lower NO <sub>x</sub> when burning solid fuels.	Lower combustion temps with solid fuels vs gas. May also reduce fuel NO <sub>x</sub> by using a fuel with less nitrogen.
16	Oxygen Enhanced Combustion	No	---	---	---	Research level	A small fraction of the combustion air is replaced with oxygen.
17	Preheat Combustion	No	---	---	---	Research level	Pulverized coal preheated and volatiles and fuel-bound nitrogen compounds are released in a controlled reducing atmosphere where the nitrogen compounds are reduced to N <sub>2</sub> .
18	ROFA-ROTAMIX	Yes	Yes	Yes	Yes	This is addressed through the scenario that combines OFA and SCR	Combination of OFA and SCR. Wall-fired or tangentially-fired furnace that utilizes high velocity overfire air. Additional NO <sub>x</sub> reductions are achieved with ammonia injection (Rotamix)
19	NO <sub>x</sub> CEMS	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
20	Parametric Monitoring	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
38	Catalyst Injection (EPS Technologies)	No	---	---	---	Research Level	A combustion catalyst is directly injected into the air intake stream and delivered to the combustion site, initiating chemical reactions that change the dynamics of the flame.
<b>Post Combustion Controls</b>							
21	Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	Yes	Yes	Not as efficient as other control technologies	Under near stoichiometric conditions, in the presence of a catalyst, NO <sub>x</sub> is reduced by CO, resulting in nitrogen (N <sub>2</sub> ) and carbon dioxide (CO <sub>2</sub> ).
22	Low Temperature Oxidation (LTO) - Tri-NO <sub>x</sub> ®	Yes	Yes	No	---	Requires ozone generation	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO <sub>x</sub>

**Cleveland Cliffs Michigan Operations BART Analysis**  
**NOx Control**  
**Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1		Step 2		Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
23	Low Temperature Oxidation (LTO) - LoTOx	Yes	No	--	--	Has been included as an "innovative" technology in recent BACT analyses from multiple facilities.	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NOx
24	Selective Catalytic Reduction (SCR)	Yes	Yes	Yes	Yes	Need to inject at appropriate temperature. Applicable to clean services.	Ammonia (NH <sub>3</sub> ) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N <sub>2</sub> and water
25	Regenerative SCR	Yes	No	--	--	For clean services. Too much debris in flue gas would poison catalyst	
26	Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes	Yes		Urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N <sub>2</sub> , and water
27	Adsorption	No	---	---	---	Still in research stages.	Use of char (activated carbon) to adsorb oxides of nitrogen
28	Absorption	Yes	Yes	Yes	Yes	Similar to TriNOx	Use of water, hydroxide and carbonate solutions, sulfuric acid, organic solutions, molten alkali carbonates, or hydroxides to absorb oxides of nitrogen.
29	Oxidizer	Yes	Yes	Yes	Yes	Redundant to regenerative SCR	Gas stream is sent through the regenerative, recuperative, catalytic or direct fired oxidizer where pollutants are heated to a combustion point and destroyed.
30	SNOX	No	--	--	--	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a concentrated liquid sulfuric acid (H <sub>2</sub> SO <sub>4</sub> ).
31	SOx-NOx-Rox-Box	No	--	--	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SOx and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NOx emissions.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology?	Step 1		Step 2		Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
							This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.
32	Electron (E-Beam) Process	No	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.
33	Electrocatalytic Oxidation	No	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NO <sub>x</sub> , and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.
34	NOXSO	No	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NO <sub>x</sub> from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NO <sub>x</sub> is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitric oxides in the flue gas. In the regeneration step, the copper sulfate is reduced in a regenerator with a reducing agent, such as natural gas, producing a concentrated stream of SO <sub>2</sub> .
36	Cold Plasma	No	---	---	---	Research Level	
37	Biofilters	No	---	---	---	Research level	Gas stream is passed through a filter medium of soil and microbes. Pollutants are adsorbed and degraded by microbial metabolism forming the products carbon dioxide and water.
38	Pahlman Process	No	---	---	---	Research Level	Gas stream is passed through a filter baghouse in which specially-developed, small-particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.

1) This number is for reference only. It does not in any way rank the control technologies.

2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.

b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/eogapt1/module6/index.htm>

c) New and Emerging Environmental Technologies, <http://neet.rti.org/>

d) ND BART Reports

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
<b>Combustion Controls</b>							
1	Overfire Air (OFA)	Yes	Yes	Yes	Yes		Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N <sub>2</sub> rather than NO <sub>x</sub>
2	External Flue Gas Recirculation (EFGR)	Yes	Yes	Yes	No		Mixes flue gas with combustion air which reduces oxygen content and therefore reduces flame temperature
3	Low-NO <sub>x</sub> Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NO <sub>x</sub> formation through restriction of oxygen, flame temperature, and/or residence time
4	Induced Flue Gas Recirculation Burners	Yes	Yes	Yes	Yes	Need to be upfired. Need convective loop to get gas recirculated	Draws flue gas to dilute the fuel in order to reduce the flame temperature
5	Low Excess Air	Yes	Yes	Yes	Yes	Reduces production	Reduces oxygen content in flue gas and reduces flame temperature
6	Burners out of Service (BOOS)	Yes	Yes	Yes	No	Need capacity of all burners for worst case scenario	Shut off the fuel flow from one burner or more to create fuel rich and fuel lean zones
7	Fuel Biasing	Yes	Yes	Yes	No		Combustion is staged by diverting fuel from the upper level burners to the lower ones or from the center to the side burners to create fuel-rich and fuel-lean zones
8	Reburning	Yes	Yes	Yes	Yes		Part of the total fuel heat input is injected into the furnace in a region above the primary (main burners) flames to create a reducing atmosphere (re-burn zone), where hydrocarbon radicals react with NO <sub>x</sub> to produce elemental nitrogen
9	Load Reduction	Yes	Yes	No	---		This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
10	Energy Efficiency Projects	Yes	Yes	Yes	Yes		Decrease amount of fuel required to make an acceptable product
11	Coal Drying	Yes	Yes	No	---	Requires available excess heat.	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
14	Combustion Zone Cooling	Yes	Yes	No	---	Could reduce load capabilities	Cooling of the primary flame zone by heat transfer to surrounding surfaces

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
15	Alternate Fuels	Yes	Yes	Yes	Yes (not required by BART)	Requires case by case analysis. Typically, facilities experience lower NO <sub>x</sub> when burning solid fuels.	Lower combustion temps with solid fuels vs gas. May also reduce fuel NO <sub>x</sub> by using a fuel with less nitrogen.
16	Oxygen Enhanced Combustion	No	---	---	---	Research level	A small fraction of the combustion air is replaced with oxygen.
17	Preheat Combustion	No	---	---	---	Research level	Pulverized coal preheated and volatiles and fuel-bound nitrogen compounds are released in a controlled reducing atmosphere where the nitrogen compounds are reduced to N <sub>2</sub> .
18	ROFA-ROTAMIX	Yes	Yes	Yes	Yes	This is addressed through the scenario that combines OFA and SCR	Combination of OFA and SCR. Wall-fired or tangentially-fired furnace that utilizes high velocity overfire air. Additional NO <sub>x</sub> reductions are achieved with ammonia injection (Rotamix)
19	NO <sub>x</sub> CEMS	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
20	Parametric Monitoring	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
38	Catalyst Injection (EPS Technologies)	No	---	---	---	Research Level	A combustion catalyst is directly injected into the air intake stream and delivered to the combustion site, initiating chemical reactions that change the dynamics of the flame.
<b>Post Combustion Controls</b>							
21	Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	Yes	Yes	For clean services. Too much debris in flue gas would poison catalyst	Under near stoichiometric conditions, in the presence of a catalyst, NO <sub>x</sub> is reduced by CO, resulting in nitrogen (N <sub>2</sub> ) and carbon dioxide (CO <sub>2</sub> ).

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
22	Low Temperature Oxidation (LTO) - Tri-NO <sub>x</sub> ®	Yes	Yes	No	---	Requires ozone generation	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO <sub>x</sub>
23	Low Temperature Oxidation (LTO) - LoTOx	Yes	No	---	---	Has been included as an "innovative" technology in recent BACT analyses from multiple facilities.	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO <sub>x</sub>
24	Selective Catalytic Reduction (SCR)	Yes	Yes	Yes	Yes	Need to inject at appropriate temperature. Applicable to clean services.	Ammonia (NH <sub>3</sub> ) is injected into the flue gas stream in the presence of a catalyst to convert NO <sub>x</sub> into N <sub>2</sub> and water
25	Regenerative SCR	Yes	No	---	---	For clean services. Too much debris in flue gas would poison catalyst	
26	Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes	Yes		Urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N <sub>2</sub> , and water
27	Adsorption	No	---	---	---	Still in research stages.	Use of char (activated carbon) to adsorb oxides of nitrogen
28	Absorption	Yes	Yes	No	---	Similar to TriNO <sub>x</sub>	Use of water, hydroxide and carbonate solutions, sulfuric acid, organic solutions, molten alkali carbonates, or hydroxides to absorb oxides of nitrogen.
29	Oxidizer	Yes	Yes	Yes	Yes	Redundant to regenerative SCR	Gas stream is sent through the regenerative, recuperative, catalytic or direct fired oxidizer where pollutants are heated to a combustion point and destroyed.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

Available and Applicable Review

DRAFT

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
30	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NO <sub>x</sub> in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a concentrated liquid sulfuric acid (H <sub>2</sub> SO <sub>4</sub> ).
31	SO <sub>x</sub> -NO <sub>x</sub> -Rox-Box	No	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SO <sub>x</sub> and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NO <sub>x</sub> emissions.
32	Electron (E-Beam) Process	No	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.
33	Electrocatalytic Oxidation	No	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NO <sub>x</sub> , and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.
34	NOXSO	No	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NO <sub>x</sub> from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NO <sub>x</sub> is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitric oxides in the flue gas. In the regeneration step, the copper sulfate is reduced in a regenerator with a reducing agent, such as natural gas, producing a concentrated stream of SO <sub>2</sub> .
36	Cold Plasma	No	---	---	---	Research Level	

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1		Step 2		Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
37	Biofilters	No	---	---	---	Research level	Gas stream is passed through a filter medium of soil and microbes. Pollutants are adsorbed and degraded by microbial metabolism forming the products carbon dioxide and water.
38	Pahlman Process	No	---	---	---	Research Level	Gas stream is passed through a filter baghouse in which specially-developed, small-particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.

- 1) This number is for reference only. It does not in any way rank the control technologies.
- 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.  
 b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/eogapt1/module6/index.htm>  
 c) New and Emerging Environmental Technologies, <http://neet.rti.org/>  
 d) ND BART Reports

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
<b>Combustion Controls</b>							
1	Overfire Air (OFA)	Yes	Yes	Yes	Yes		Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N <sub>2</sub> rather than NO <sub>x</sub>
2	External Flue Gas Recirculation (EFGR)	Yes	Yes	Yes	No		Mixes flue gas with combustion air which reduces oxygen content and therefore reduces flame temperature
3	Low-NO <sub>x</sub> Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NO <sub>x</sub> formation through restriction of oxygen, flame temperature, and/or residence time
4	Induced Flue Gas Recirculation Burners	Yes	Yes	Yes	Yes	Need to be upfired. Need convective loop to get gas recirculated	Draws flue gas to dilute the fuel in order to reduce the flame temperature
5	Low Excess Air	Yes	Yes	Yes	Yes	Reduces production	Reduces oxygen content in flue gas and reduces flame temperature
6	Burners out of Service (BOOS)	Yes	Yes	Yes	No	Need capacity of all burners for worst case scenario	Shut off the fuel flow from one burner or more to create fuel rich and fuel lean zones
7	Fuel Biasing	Yes	Yes	Yes	No		Combustion is staged by diverting fuel from the upper level burners to the lower ones or from the center to the side burners to create fuel-rich and fuel-lean zones
8	Reburning	Yes	Yes	Yes	Yes		Part of the total fuel heat input is injected into the furnace in a region above the primary (main burners) flames to create a reducing atmosphere (re-burn zone), where hydrocarbon radicals react with NO <sub>x</sub> to produce elemental nitrogen
9	Load Reduction	Yes	Yes	No	---		This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
10	Energy Efficiency Projects	Yes	Yes	Yes	Yes		Decrease amount of fuel required to make an acceptable product
11	Coal Drying	Yes	Yes	No	---	Requires available excess heat.	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
14	Combustion Zone Cooling	Yes	Yes	No	---	Could reduce load capabilities	Cooling of the primary flame zone by heat transfer to surrounding surfaces

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
15	Alternate Fuels	Yes	Yes	Yes	Yes (not required by BART)	Requires case by case analysis. Typically, facilities experience lower NO <sub>x</sub> when burning solid fuels.	Lower combustion temps with solid fuels vs gas. May also reduce fuel NO <sub>x</sub> by using a fuel with less nitrogen.
16	Oxygen Enhanced Combustion	No	---	---	---	Research level	A small fraction of the combustion air is replaced with oxygen.
17	Preheat Combustion	No	---	---	---	Research level	Pulverized coal preheated and volatiles and fuel-bound nitrogen compounds are released in a controlled reducing atmosphere where the nitrogen compounds are reduced to N <sub>2</sub> .
18	ROFA-ROTAMIX	Yes	Yes	Yes	Yes	This is addressed through the scenario that combines OFA and SCR	Combination of OFA and SCR. Wall-fired or tangentially-fired furnace that utilizes high velocity overfire air. Additional NO <sub>x</sub> reductions are achieved with ammonia injection (Rotamix)
19	NO <sub>x</sub> CEMS	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
20	Parametric Monitoring	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NO <sub>x</sub> emissions	Optimization of combustion
38	Catalyst Injection (EPS Technologies)	No	---	---	---	Research Level	A combustion catalyst is directly injected into the air intake stream and delivered to the combustion site, initiating chemical reactions that change the dynamics of the flame.
<b>Post Combustion Controls</b>							
21	Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	Yes	Yes	For clean services. Too much debris in flue gas would poison catalyst	Under near stoichiometric conditions, in the presence of a catalyst, NO <sub>x</sub> is reduced by CO, resulting in nitrogen (N <sub>2</sub> ) and carbon dioxide (CO <sub>2</sub> ).

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
22	Low Temperature Oxidation (LTO) - Tri-NO <sub>x</sub> ®	Yes	Yes	No	---	Requires ozone generation	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO <sub>x</sub>
23	Low Temperature Oxidation (LTO) - LoTOx	Yes	No	---	---	Has been included as an "innovative" technology in recent BACT analyses from multiple facilities.	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NO <sub>x</sub>
24	Selective Catalytic Reduction (SCR)	Yes	Yes	Yes	Yes	Need to inject at appropriate temperature. Applicable to clean services.	Ammonia (NH <sub>3</sub> ) is injected into the flue gas stream in the presence of a catalyst to convert NO <sub>x</sub> into N <sub>2</sub> and water
25	Regenerative SCR	Yes	No	---	---	For clean services. Too much debris in flue gas would poison catalyst	
26	Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes	Yes		Urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N <sub>2</sub> , and water
27	Adsorption	No	---	---	---	Still in research stages.	Use of char (activated carbon) to adsorb oxides of nitrogen
28	Absorption	Yes	Yes	No	---	Similar to TriNO <sub>x</sub>	Use of water, hydroxide and carbonate solutions, sulfuric acid, organic solutions, molten alkali carbonates, or hydroxides to absorb oxides of nitrogen.
29	Oxidizer	Yes	Yes	Yes	Yes	Redundant to regenerative SCR	Gas stream is sent through the regenerative, recuperative, catalytic or direct fired oxidizer where pollutants are heated to a combustion point and destroyed.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

Available and Applicable Review

DRAFT

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
30	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NO <sub>x</sub> in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a concentrated liquid sulfuric acid (H <sub>2</sub> SO <sub>4</sub> ).
31	SO <sub>x</sub> -NO <sub>x</sub> -Rox-Box	No	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SO <sub>x</sub> and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NO <sub>x</sub> emissions.
32	Electron (E-Beam) Process	No	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.
33	Electrocatalytic Oxidation	No	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NO <sub>x</sub> , and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.
34	NOXSO	No	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NO <sub>x</sub> from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NO <sub>x</sub> is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitric oxides in the flue gas. In the regeneration step, the copper sulfate is reduced in a regenerator with a reducing agent, such as natural gas, producing a concentrated stream of SO <sub>2</sub> .
36	Cold Plasma	No	---	---	---	Research Level	

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Process Boilers**

**Available and Applicable Review**

**DRAFT**

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1		Step 2		Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
37	Biofilters	No	---	---	---	Research level	Gas stream is passed through a filter medium of soil and microbes. Pollutants are adsorbed and degraded by microbial metabolism forming the products carbon dioxide and water.
38	Pahlman Process	No	---	---	---	Research Level	Gas stream is passed through a filter baghouse in which specially-developed, small-particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.

- 1) This number is for reference only. It does not in any way rank the control technologies.
- 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.  
 b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/eogapt1/module6/index.htm>  
 c) New and Emerging Environmental Technologies, <http://neet.rti.org/>  
 d) ND BART Reports

**Cleveland Cliffs Michigan Operations - Taconite BART Analysis**  
**SO2 Control**  
**Indurating Furnaces**

**Available and Applicable Review**

Revised: December 1, 2006

This table is part of the CCMO Taconite BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

Reference No.	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1				Step 2		Approximate Control Efficiency	Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to indurating furnaces?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?					
1	Wet Scrubbing (High Efficiency)	Y	Y	Y	Y	90-95%		Absorption and reaction using an alkaline reagent to produce a solid compound		
2	Wet Scrubbing (Low Efficiency)	Y	Y	Y	Y	<50%		Absorption and reaction using an alkaline reagent to produce a solid compound		
3	Wet Walled Electrostatic Precipitator (WWESP)	Y	Y	Y	Y	80%		Suspended particles are separated from the flue gas stream, attracted to plates, and collected in hoppers		
4	Dry sorbent injection	Y	Y	Y	Y	<55%		Pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO <sub>2</sub> onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter		
5	Spray Dryer Absorption (SDA)	Y	Y	Y	Y	<90%		Lime slurry is sprayed into an absorption tower where SO <sub>2</sub> is absorbed by the slurry, forming CaSO <sub>3</sub> /CaSO <sub>4</sub>		
6	Alternative Fuels	Y	Y	Y (for furnaces capable of multiple fuels)	Y (not required by BART)	Site-specific	Natural gas is base case	Use a fuel with lower sulfur content.		
7	Load Reduction	N	---	---	---	---	Power plant technology	This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.		
8	Energy Efficiency Projects	Y	Y	Y (for large projects like heat-recoup)	Y (for large projects like heat-recoup)	Site-specific		decrease amount of fuel required to make an acceptable product		
9	Coal Processing	Y	N	---	---	---	Applies only to facilities that burn coal	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project		
10	Bio Filters	N	---	---	---	---	Research level	Gas stream passes through a packed bed of specially engineered biomedium which supports the growth of active bacterial species. The pollutants in the gas stream are biodegraded or biotransformed into innocuous products, such as carbon dioxide, water, chlor		
11	CANSOLV Regenerable SO <sub>2</sub>	N	---	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO <sub>2</sub> from the feed gas in a countercurrent absorption tower. The rich solvent is regenerated by steam stripping, giving a byproduct of pure, water saturated SO <sub>2</sub> gas and lean solvent for recycling to the a		
12	Pahlman Process	N	---	---	---	---	Research level	Gas stream is passed through a filter baghouse in which specially-developed, small particle, high-surface area metal oxide sorbent have been deployed. Pollutants are removed from the gases by adsorption.		
13	SOx-NOx-Rox-Box	N	---	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SOx and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NOx emissions.		

**Cleveland Cliffs Michigan Operations - Taconite BART Analysis  
SO2 Control  
Indurating Furnaces**

**Available and Applicable Review**

Revised: December 1, 2006

Reference No.	SO <sub>2</sub> Pollution Control Technology <sup>2</sup>	Step 1				Step 2		Approximate Control Efficiency	Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to indurating furnaces?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?					
14	Electron (E-Beam) Process	N	---	---	---	---	---	No operating commercial applications on coal	Electron beam irradiation in the presence of ammonia to initiate chemical conversion of sulfur and nitrogen oxides into components which can be easily collected by conventional methods such as an ESP or baghouse.	
15	Electrocatalytic Oxidation	N	---	---	---	---	---	Similar to cold plasma. Will keep watch for availability of this technology	Utilizes a reactor in which SO <sub>2</sub> , NO <sub>x</sub> , and mercury are oxidized to nitrogen dioxide (NO <sub>2</sub> ), sulfuric acid, and mercuric oxide respectively using non-thermal plasma.  On recent project, the vender was doing final trials on full-scale applications.	
16	NOXSO	N	---	---	---	---	---	Commercial version of adsorption. Limited experience (proof-of-concept tests).	Uses a regenerable sorbent to simultaneously adsorb SO <sub>2</sub> and NO <sub>x</sub> from flue gas from coal-fired utility and industrial boilers. In the process, the SO <sub>2</sub> is converted to a saleable sulfur by-product (liquid SO <sub>2</sub> , elemental sulfur, or sulfuric acid) and the NO <sub>x</sub>	
17	Copper-Oxide	N	---	---	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO <sub>2</sub> in the flue gas reacts with copper oxide, supported on small spheres of alumina, to form copper sulfate. Ammonia is injected into the flue gas before the absorption reactor and a selective catalytic reduction-type reaction occurs that reduces the nitr	
18	SNOX	N	---	---	---	---	---	Early commercial development stage	Catalytic reduction of NO <sub>x</sub> in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a	
19	Cold Plasma	N	---	---	---	---	---	Research level		

- 1) This number is for reference only. It does not in any way rank the control technologies.  
 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.  
 2) b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/cogapfi1/module6/index.htm>  
 2) c) New and Emerging Environmental Technologies, <http://neet.rti.org/>  
 2) d) ND BART Reports

**Cleveland Cliffs Michigan Operations BART Analysis**  
**NOx Control**  
**Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

Reference No. <sup>1</sup>	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
<b>Combustion Controls</b>							
1	Overfire Air (OFA)	Yes	Yes	Yes	Yes		Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N <sub>2</sub> rather than NO <sub>x</sub>
2	External Flue Gas Recirculation (EFGR)	Yes	Yes	Yes	No		Mixes flue gas with combustion air which reduces oxygen content and therefore reduces flame temperature
3	Low-NO <sub>x</sub> Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NO <sub>x</sub> formation through restriction of oxygen, flame temperature, and/or residence time
4	Induced Flue Gas Recirculation Burners	Yes	Yes	Yes	Yes	Need to be upfired. Need convective loop to get gas recirculated	Draws flue gas to dilute the fuel in order to reduce the flame temperature
5	Low Excess Air	Yes	Yes	Yes	Yes	Reduces production	Reduces oxygen content in flue gas and reduces flame temperature
6	Burners out of Service (BOOS)	Yes	Yes	Yes	No	Need capacity of all burners for worst case scenario	Shut off the fuel flow from one burner or more to create fuel rich and fuel lean zones
7	Fuel Biasing	Yes	Yes	Yes	No		Combustion is staged by diverting fuel from the upper level burners to the lower ones or from the center to the side burners to create fuel-rich and fuel-lean zones
8	Reburning	Yes	Yes	Yes	No		Part of the total fuel heat input is injected into the furnace in a region above the primary (main burners) flames to create a reducing atmosphere (re-burn zone), where hydrocarbon radicals react with NO <sub>x</sub> to produce elemental nitrogen
9	Load Reduction	Yes	Yes	No	---		This is a strategy to reduce load on a power plant by reducing the electrical demand through efficiency projects.
10	Energy Efficiency Projects	Yes	Yes	Yes	Yes		Decrease amount of fuel required to make an acceptable product
11	Coal Drying	Yes	Yes	No	---	Requires available excess heat.	Dry coal will increase the as-burned BTU value, and therefore less fuel is required to be burned. Specific energy efficiency project
14	Combustion Zone Cooling	Yes	Yes	No	---	Could reduce load capabilities	Cooling of the primary flame zone by heat transfer to surrounding surfaces

**Cleveland Cliffs Michigan Operations BART Analysis**  
**NOx Control**  
**Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

Reference No.	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.							
15	Alternate Fuels	Yes	Yes	Yes	Yes (not required by BART)	Requires case by case analysis. Typically, facilities experience lower NOx when burning solid fuels.	Lower combustion temps with solid fuels vs gas. May also reduce fuel NOx by using a fuel with less nitrogen.
16	Oxygen Enhanced Combustion	No	---	---	---	Research level	A small fraction of the combustion air is replaced with oxygen.
17	Preheat Combustion	No	---	---	---	Research level	Pulverized coal preheated and volatiles and fuel-bound nitrogen compounds are released in a controlled reducing atmosphere where the nitrogen compounds are reduced to N <sub>2</sub> .
18	ROFA-ROTAMIX	Yes	Yes	Yes	Yes	This is addressed through the scenario that combines OFA and SCR	Combination of OFA and SCR. Wall-fired or tangentially-fired furnace that utilizes high velocity overfire air. Additional NOx reductions are achieved with ammonia injection (Rotamix)
19	NOx CEMS	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NOx emissions	Optimization of combustion
20	Parametric Monitoring	Yes	Yes	Yes	No	Current equipment cannot be tuned to impact NOx emissions	Optimization of combustion
38	Catalyst Injection (EPS Technologies)	No	---	---	---	Research Level	A combustion catalyst is directly injected into the air intake stream and delivered to the combustion site, initiating chemical reactions that change the dynamics of the flame.
<b>Post Combustion Controls</b>							
21	Non-Selective Catalytic Reduction (NSCR)	Yes	Yes	Yes	Yes	Not as efficient as other control technologies	Under near stoichiometric conditions, in the presence of a catalyst, NOx is reduced by CO, resulting in nitrogen (N <sub>2</sub> ) and carbon dioxide (CO <sub>2</sub> ).
22	Low Temperature Oxidation (LTO) - Tri-NOx®	Yes	Yes	No	---	Requires ozone generation	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NOx

**Cleveland Cliffs Michigan Operations BART Analysis**  
**NOx Control**  
**Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

Reference No. <sup>1</sup>	NO <sub>x</sub> Pollution Control Technology <sup>2</sup>	Step 1	Step 2			Comments	Basic Principle
		Is this a generally available control technology?	Is the control technology available to power boilers?	Is the control technology applicable to this specific source?	Is it technically feasible for this source?		
23	Low Temperature Oxidation (LTO) - LoTOx	Yes	No	---	---	Has been included as an "innovative" technology in recent BACT analyses from multiple facilities.	Utilizes an oxidizing agent such as ozone to oxidize various pollutants including NOx
24	Selective Catalytic Reduction (SCR)	Yes	Yes	Yes	Yes	Need to inject at appropriate temperature. Applicable to clean services.	Ammonia (NH <sub>3</sub> ) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N <sub>2</sub> and water
25	Regenerative SCR	Yes	No	---	---	For clean services. Too much debris in flue gas would poison catalyst	
26	Selective Non-Catalytic Reduction (SNCR)	Yes	Yes	Yes	Yes		Urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N <sub>2</sub> , and water
27	Adsorption	No	---	---	---	Still in research stages.	Use of char (activated carbon) to adsorb oxides of nitrogen
28	Absorption	Yes	Yes	Yes	Yes	Similar to TriNOx	Use of water, hydroxide and carbonate solutions, sulfuric acid, organic solutions, molten alkali carbonates, or hydroxides to absorb oxides of nitrogen.
29	Oxidizer	Yes	Yes	Yes	Yes	Redundant to regenerative SCR	Gas stream is sent through the regenerative, recuperative, catalytic or direct fired oxidizer where pollutants are heated to a combustion point and destroyed.
30	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH <sub>3</sub> ), followed by catalytic oxidation of SO <sub>2</sub> to SO <sub>3</sub> . The exit gas from the SO <sub>3</sub> converter passes through a novel glass-tube condenser in which the SO <sub>3</sub> is hydrated to H <sub>2</sub> SO <sub>4</sub> vapor and then condensed to a concentrated liquid sulfuric acid (H <sub>2</sub> SO <sub>4</sub> ).
31	SOx-NOx-Rox-Box	No	---	---	---	Technology has not been demonstrated	Dry sorbent injection upstream of the baghouse for removal of SOx and ammonia injection upstream of a zeolitic selective catalytic reduction (SCR) catalyst incorporated in the baghouse to reduce NOx emissions.

**Cleveland Cliffs Michigan Operations BART Analysis  
NOx Control  
Dryer**

**Available and Applicable Review**

Revised: December 1, 2006

		Step 1	Step 2				
<b>Reference No.</b>	<b>NO<sub>x</sub> Pollution Control Technology<sup>2</sup></b>	<b>Is this a generally available control technology?</b>	<b>Is the control technology available to power boilers?</b>	<b>Is the control technology applicable to this specific source?</b>	<b>Is it technically feasible for this source?</b>	<b>Comments</b>	<b>Basic Principle</b>

This table is part of the CCMO Process Boiler BART Report and should not be distributed without the full text of the report so that the information is not taken out of context.

- 2) a) Air Pollution: Its Origin And Control. Wark, Kenneth; Warner, Cecil F.; and Davis, Wayne T. 1998. Addison Wesley Longman, Inc.  
 b) US EPA Basic Concepts in Environmental Science, Module 6, <http://www.epa.gov/eogapti1/module6/index.htm>  
 c) New and Emerging Environmental Technologies, <http://neet.rti.org/>  
 d) ND BART Reports

Appendix E Clean Air Interstate Rule (CAIR), Cost-Effective Air Pollution Controls

Reference	Regulatory Body/Rule	Avg. Expected Values (\$/ton)		Limiting/Marginal values (\$/ton)		Comments
		SO2	NOx	SO2	NOx	
FR_Notice_6JULY05_Final_Rule.pdf	BART	100 to 1000	100 to 1000			70 FR 39135
	BART		281 to 1296			70 FR 39135 Table 3
	BART	919				70 FR 39133
	BART					Guidelines disparagingly reference "thousands of dollars per ton" in commenting on the need to exceed MACT and its general unreasonableness.
70_FR_25210_CAIR.pdf	CAIR		1300			Estimated Marginal cost 2009
FR_Notice_5MAY04_Proposed_Rule.pdf	BART(proposed rule)	200-1000				BART proposed lists this as values for 90-95% SO2 control, which is still assumed, or .1 to .15 lb/MMBtu. Dropped from final to give states flexibility to require more. Says for scrubbers, bypasses aren't BART, only 100% scrubbing is BART.
	BART(proposed rule)					0.2 lb/MMBtu for NOx is assumed reasonable. Recognizes that some sources may need SCR to get this level. For those, state discretion of the the cost vs. visibility value is necessary.
MidwestRPO_rept_referencing_CAIR.pdf	CAIR(using IPM)			1000	1500	
	CAIR ( 2009 in 1999\$)		900		2400	
	CAIR ( 2015 in 1999\$)		1800		3000	
	CAIR (depending on Nat'l emissions)			1200 - 3000	1400- 2100	This was modeled with TRUM (Technology Retrofitting Updating Model) to develop the marginal values.
Kammer_EPA_Decision.doc	Kammer Decision			over 1000	over 1000	
LADCO_MidwestRPO_Boiler_Analysis.pdf	LADCO/Midwest RPO	1240 to 3822	607 to 4493			
MANE-VU_BART_Control_Assessment.pdf	MANE-VU			200-500	200-1500	
Bowers_vs_SWAPCA.txt	Bowers vs SWAPCA	300	300	1000	1000	954-1134 was ruled too much, in favor of 256-310 for SO2. This did consider incremental value. Sections XVII to XIX
WRAP_Trading_program_methodology.pdf	WRAP			3000		
	EPA - Referenced by Wrap					References EPA-600S\7-90-018. Low is <\$500/ton, Moderate is \$500-3000/ton, High is over \$3000/ton

## 1. BART Eligibility

BART eligibility is established on the basis on three criteria. In order to be BART-eligible, sources must meet the following three conditions:

1. Contain emission units in one or more of the 26 listed source categories under the PSD rules (e.g., taconite ore processing plants, fossil-fuel-fired steam electric plants larger than 250 mmBtu/hr, fossil-fuel boilers larger than 250 mmBtu/hr, petroleum refineries, coal cleaning plants, sulfur recovery plants, etc.);
2. Were in existence on August 7, 1977, but were not in operation before August 7, 1962;
3. Have total potential emissions greater than 250 tons per year for at least one visibility-impairing pollutant from the emission units meeting the two criteria above.

Under the BART rules, large sources that have previously installed pollution control equipment required under another standard (e.g., MACT, NSPS and BACT) will be required to conduct visibility analyses. Installation of additional controls may be required to further reduce emissions of visibility impairing pollutants such as particulate matter (PM), PM<sub>10</sub>, PM<sub>2.5</sub>, sulfur dioxide (SO<sub>2</sub>), nitrous oxide (NO<sub>x</sub>), and possibly Volatile Organic Compounds (VOCs) and ammonia. Sources built before the implementation of the Clean Air Act (CAA), which had previously been grandfathered, may also have to conduct such analyses and possibly install controls, even though they have been exempted to date from any other CAA requirements.

Once BART eligibility is determined, a source must then determine if it is ‘subject to BART.’ A source is subject to BART if emissions “cause or contribute” to visibility impairment at any Class I area. Visibility modeling conducted with CALPUFF or another U.S. EPA-approved visibility model is necessary to make a definitive visibility impairment determination (>0.5 deciviews). Sources that do not cause or contribute to visibility impairment are exempt from BART requirements, even if they are BART-eligible.

## 2. BART Determinations

Each source that is subject to BART must determine BART on a case-by-case basis. Even if a source was previously part of a group BART determination, individual BART determinations must be made for each source. The BART analysis takes into account six criteria and is

analyzed using five steps. The six criteria that comprise the engineering analysis include: the availability of the control technology, existing controls at a facility, the cost of compliance, the remaining useful life of a source, the energy and non-air quality environmental impacts of the technology, and the visibility impacts.<sup>1</sup> The five steps of a BART analysis are:

***Step 1 - Identify all Available Retrofit Control Technologies***

The first step in the analysis is to identify all retrofit control technologies which are generally available for each applicable emission unit. Available retrofit control technologies are defined by U.S. EPA in Appendix Y to Part 51 (Guidelines for BART Determinations under the Regional Haze Rule) as follows:

*Available retrofit technologies 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. Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives. The control alternatives can 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 or 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 been demonstrated in practice.<sup>2</sup>*

***Step 2 - Eliminate Technically Infeasible Options***

In the second step, the source-specific technical feasibility of each control option identified in step one is evaluated by answering three specific questions:

---

<sup>1</sup> 40 CFR 51 Appendix Y

<sup>2</sup> Federal Register 70, No. 128 (July 6, 2005): 39164

- a. Is the control technology “available” to the specific source which is undergoing the BART analysis?

The U.S. EPA states that a control technique is considered “available” to a specific source “if it has reached the stage of licensing and commercial availability.”<sup>3</sup> However, the U.S. EPA further states that they “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.”<sup>4</sup>

- b. Is the control technology an “applicable technology” for the specific source which is undergoing the BART analysis?

In general, a commercially available control technology, as defined in question 1, “will be presumed applicable if it has been used on the same or a similar source type.”<sup>5</sup> If a control technology has not been demonstrated on a same or a similar source type, the technical feasibility is determined by “examining the physical and chemical characteristics of the pollutant-bearing stream and comparing them to the gas stream characteristics of the source types to which the technology has been applied previously.”<sup>6</sup>

- c. Are there source-specific issues/conditions that would make the control technology not technically feasible?

This question addresses specific circumstances that “preclude its application to a particular emission unit.” This demonstration typically includes an “evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology.”<sup>7</sup> This also involves the identification of “un-resolvable technical difficulties.” However, when the technical difficulties are merely a matter of increased cost, the technology

---

<sup>3</sup> Federal Register 70, No. 128 (July 6, 2005): 39165

<sup>4</sup> IBID

<sup>5</sup> IBID

<sup>6</sup> IBID

<sup>7</sup> IBID

should be considered technically feasible and the technological difficulty evaluated as part of the economic analysis<sup>8</sup>.

It is also important to note that vendor guarantees can provide an indication of technical feasibility but the U.S. EPA does not “consider a vendor guarantee alone to be sufficient justification that a control option will work.” Conversely, the U.S. EPA does not consider as “sufficient justification that a control option or emission limit is technically infeasible. In general, the decisions on technical feasibility should be based on a combination of the evaluation of the chemical and engineering analysis and the information from vendor guarantees<sup>9</sup>.

***Step 3 - Evaluate Control Effectiveness***

In step three, the remaining controls are ranked based on the control efficiency at the expected emission rate (post-control) as compared to the emission rate before addition of controls (pre-BART) for the pollutant of concern.

***Step 4 - Evaluate Impacts and Document Results***

In the fourth step, an engineering analysis documents the impacts of each remaining control technology option. The economic analysis compares dollar per ton of pollutant removed for each technology. In addition, it includes incremental dollar per ton cost analysis to illustrate the economic effectiveness of one technology in relation to the others. Finally, step four includes an assessment of energy impacts and other non-air quality environmental impacts.

***Step 5 - Evaluate Visibility Impacts***

The fifth step requires a modeling analysis conducted with U.S. EPA-approved models such as CALPUFF. The modeling protocol<sup>10</sup>, including receptor grid, meteorological data, and other factors used for this part of the analysis were provided by the MDEQ. The model outputs, including the 98th percentile deciview (dV) value and the number of days the facility contributes more than a 0.5 dV of visibility impairment at each of the Class I areas, are used to establish the degree of improvement that can be reasonably attributed to each technology.

---

<sup>8</sup> IBID

<sup>9</sup> IBID

<sup>10</sup> LADCO. March 21, 2006. *Single Source Modeling to Support Regional Haze BART Modeling Protocol*.

The final step in the BART analysis is to select the “best” alternative using the results of steps 1 through 5. In addition, the U.S. EPA guidance states that the “affordability” of the controls should be considered, and specifically states:

- 1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of plant operations.*
- 2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have severe impacts on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether competing plants in the same industry have been required to install BART controls if this information is available.<sup>11</sup>*

To complete the BART process, the analysis must “establish enforceable emission limits that reflect the BART requirements and requires compliance within a reasonable period of time<sup>12</sup>.” Those limits must be developed for inclusion in the state implementation plan (SIP) that is due to U.S. EPA in December of 2007. In addition, the analysis must include requirements that the source “employ techniques that ensure compliance on a continuous basis<sup>13</sup>,” which could include the incorporation of other regulatory requirements for the source, including Compliance Assurance Monitoring (40 CFR 64), Periodic Monitoring (40 CFR 70.6(a)(3)) and Sufficiency Monitoring (40 CFR 70(6)(c)(1)). If technological or economic limitations make measurement methodology for an emission unit infeasible, the

---

<sup>11</sup> Federal Register 70, No. 128 (July 6, 2005): 39171.

<sup>12</sup> Federal Register 70, No. 128 (July 6, 2005): 39172.

<sup>13</sup> IBID.

BART limit can “instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards<sup>14</sup>.”

Compliance with the BART emission limits will be required within 5 years of U.S. EPA approval of the Michigan SIP.

---

<sup>14</sup> IBID.

## DRAFT BART Eligible Emission Units Subject to a Streamlined BART Analysis

### 1.0 Indurating Furnaces (PM Only)

The indurating furnaces are sources of three visibility impairing pollutants: NO<sub>x</sub>, SO<sub>2</sub>, and PM. Relative to NO<sub>x</sub> and SO<sub>2</sub>, PM is not a major visibility impairing pollutant. Further, the indurating furnaces are subject to the taconite Maximum Achievable Control Technologies (MACT) standard [40 CFR Subpart RRRRR-NESHAPS: Taconite Iron Ore Processing] for the PM emissions. In 40 CFR Part 51 Appendix Y paragraph IV.C., it states:

*For VOC and PM sources subject to MACT standards, States may streamline the analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards. We believe that there are many VOC and PM sources that are well controlled because they are regulated by the MACT standards, which EPA developed under CAA section 112. For a few MACT standards, this may also be true for SO<sub>2</sub>. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. Examples of these hazardous air pollutant sources which effectively control VOC and PM emissions include (among others) secondary lead facilities, organic chemical plants subject to the hazardous organic NESHAP (HON), pharmaceutical production facilities, and equipment leaks and wastewater operations at petroleum refineries. We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. **Unless there are new technologies subsequent to the MACT standards which would lead to cost effective increases in the level of control, you may rely on the MACT standards for purposes of BART.**(emphasis added)*

It is clear from EPA's guidance that they are encouraging states to develop a streamlined BART analysis approach for sources regulated under a MACT. Since the Taconite MACT standard was established very recently and becomes effective in 2006, the technology analysis is up-to-date. As a result, BART will be presumed to be equivalent to MACT for PM.

A full BART analysis will be conducted for NO<sub>x</sub> and SO<sub>2</sub> where applicable.

### 2.0 Taconite MACT Emission Units (PM-Only)

In addition to the indurating furnaces, the taconite MACT standard also regulates PM emissions from Ore Crushing and Handling operations, Pellet Coolers, and Finished Pellet Handling operations. These sources operate near ambient temperature, only emit PM, and do not emit NO<sub>x</sub> or SO<sub>2</sub>. The Ore Crushing and Handling sources and the Finished Pellet Handling sources operate with control equipment to meet the applicable MACT limits (0.008 gr/dscf for existing sources and 0.005 gr/dscf for new sources). The Pellet Cooler sources are excluded from additional control under the MACT standard due to *the large size of the particles and the relatively low concentration of particle emissions* [FR, December 18, 2002, page 77570].

Since the MACT standard was established recently and will become effective in 2006, the technology analysis is up-to-date. Again, for these units subject to a MACT standard, BART will be presumed to be equivalent to MACT according to U.S. EPA guidance.

No further analysis will be required to establish BART for these sources.

### **3.0 Process Boiler MACT Emission Units (PM-Only)**

Similarly to sources subject to the Taconite MACT, a taconite processing facility has many process boilers subject to the Boiler MACT. Since the MACT standard was established recently and will become effective in 2007, the technology analysis is up-to-date. Again, for these units subject to a MACT standard, BART will be presumed to be equivalent to MACT according to U.S. EPA guidance.

No further analysis will be required to establish BART for these sources.

### **4.0 Process Boiler Emission Units (NO<sub>x</sub> and SO<sub>2</sub>)**

It is important to note that the emissions from the indurating furnaces represent the vast majority of emissions of all visibility impairing pollutants, with the process boiler emission units typically contributing less than 1% of the total emissions of each pollutant from sources that are subject to BART. The emissions from all the remaining sources are small relative to the total emissions that are subject to the BART standard. Additional control of these sources can be presumed to have minimal impact on visibility improvement in Class I areas. Each facility will conduct an analysis for the remaining sources to demonstrate that the impact on visibility is negligible. The procedure for the analysis is detailed in section 5 of this document. Assuming that the modeling demonstrates that the sources have a negligible impact on visibility in Class I areas, no further analysis will be required to establish BART for these sources.

### **5.0 Visibility Impact Modeling for Negligible Impacts**

As described in sections 3 and 4 of this document, each facility contains several process boilers that are assumed to have a negligible impact on visibility in Class I areas. In order to confirm this assumption, each facility will conduct a modeling analysis to determine the impact of the emissions from these sources on visibility in Class I areas. The analysis will consist of the following:

- A. Conduct air dispersion modeling for uncontrolled BART-eligible emission unit, as described in sections 3 and 4 above. The modeling will be conducted based on the guidance document *Single Source Modeling to Support Regional Haze BART Modeling Protocol* dated March 21, 2006 as prepared by Lake Michigan Air

- Directors Consortium (LADCO). One modeling analysis will be conducted for each facility.
- B. Count the days with a 98<sup>th</sup> percentile (21 over 3-yrs, 7 each year) change in visibility greater than or equal to 0.05 deciviews (based on 10% of the facility threshold of 0.5 deciviews) at the modeled receptors within the boundaries of each Class I area assessed over the 3-year period 2002-2004.
  - C. If the modeled emission sources result in a 98<sup>th</sup> percentile change in visibility less than or equal to 0.05 deciviews, the point sources will be considered to not cause or contribute to visibility impairment in Class I areas. Therefore, the existing operations will be considered BART. No further analysis will be required to establish BART for these sources.
  - D. If the modeled emissions result in a 98<sup>th</sup> percentile change in visibility greater than or equal to 0.05 deciviews, a full BART analysis will be conducted on the emission sources.