Appendix 9D

Lafarge Global Settlement/Consent Decree - Alpena Facility

UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF ILLINOIS

UNITED STATES OF AMERICA,

Plaintiff,

and the STATE of ALABAMA, the STATE
of ILLINOIS, the STATE of IOWA,
the STATE of KANSAS, the STATE of
MICHIGAN, the STATE of MISSOURI,
the STATE of NEW YORK, the STATE
OF OHIO, the STATE of PENNSYLVANIA,
the STATE of SOUTH CAROLINA
DEPARTMENT OF HEALTH AND
ENVIRONMENTAL CONTROL,
the WASHINGTON STATE
DEPARTMENT OF ECOLOGY,
the OKLAHOMA DEPARTMENT OF
ENVIRONMENTAL QUALITY, and
the PUGET SOUND CLEAN AIR AGENCY,

Plaintiff-Intervenors,

Civil Action No. 3:10-cv-0004-JPG-CJP

v.

LAFARGE NORTH AMERICA, INC.,
LAFARGE MIDWEST, INC., and
LAFARGE BUILDING MATERIALS, INC.,

Defendants.

CONSENT DECREE

V. NO_x CONTROL TECHNOLOGY, EMISSION LIMITS, TONNAGE LIMITS, AND MONITORING REQUIREMENTS

A. NO_x Control Technology, Emission Limits and Tonnage Limits.

11. Subject to Section VII (Temporary Cessation of Kiln Operation), the Lafarge Companies shall install the NO_x Control Technology and comply with the Emission Limits and Tonnage Limits for the specific Facilities and Kilns within their system according to Paragraphs 11 through 44. The Lafarge Companies shall Continuously Operate each NO_x Control Technology as applicable to each Kiln at all times of Kiln Operation, except for periods of Malfunction of the NO_x Control Technology. Compliance with any requirement of this Section V (NO_x Control Technology, Emission Limits, Tonnage Limits, and Monitoring Requirements) relating to any specific Facility or Kiln shall not be required if the Lafarge Companies Retire any such Facility or Kiln prior to any date for compliance. If one or more Kilns at a Facility is in Temporary Cessation, then the following provisions shall apply in addition to any other requirements in this Consent Decree:

a. The Lafarge Companies shall comply with the applicable Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit at all other Kilns not in Temporary Cessation at the Facility within 12 months of the Day on which the last Optimization Phase was concluded (as determined by U.S. EPA and the Affected State) at a Kiln not in Temporary Cessation at the Facility; and

b. The Lafarge Companies shall comply with the applicable Facility-Wide 12-Month Rolling Average Emission Limit and Facility-Wide 12-Month Rolling Tonnage Limit at all other Kilns not in Temporary Cessation on the dates required in this Section V (NO_x Control Technology, Emission Limits, Tonnage Limits and Monitoring Requirements).

Alpena

12. By January 1, 2011, the Lafarge Companies shall achieve and maintain compliance with an interim Facility-Wide 12-Month Rolling Tonnage Limit for NO_x of 8,650 tons.

13. Control Technology Retrofit Option.

a. Subject to Section VII (Temporary Cessation of Kiln Operation), the Lafarge Companies shall have installed and Commenced Continuous Operation of the SNCR technology specified in the table below on individual Kilns in the order selected by the Lafarge Companies within each specified Kiln Group ("KG") at the Alpena Facility by the dates specified below:

Kiln	**Control Technology**	**Date of Installation and Commencement of Continuous Operation**	**30-Day Rolling Average Emission Limits (lbs. NO_x/Ton of clinker)**	**Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit (lbs. NO_x/Ton of clinker)**
1st Kiln in KG5	SNCR	10/1/2011	*See* Appendix	4.89
2nd Kiln in KG5	SNCR	11/1/2011	*See* Appendix	
3rd Kiln in KG5	SNCR	12/1/2011	*See* Appendix	
1st Kiln in KG6	SNCR	1/1/2012	*See* Appendix	
2nd Kiln in KG6	SNCR	3/1/2012	*See* Appendix	

b. Upon installation of the Control Technology, the Lafarge Companies shall Continuously Operate the SNCR technology during all times of Kiln Operation, except during periods of SNCR technology Malfunction.

c. If the Lafarge Companies elect not to Retire and Replace any Alpena Kiln in accordance with Section VIII (Election to Retire and Replace Kilns), then:

    i. Within 12 months after the conclusion of the Optimization Phase as it applies to Kilns 19, 20, and 21 (KG5) identified in Paragraphs 13 and 7.z(1), the Lafarge Companies shall achieve and maintain compliance with the Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit for NO_x of 4.89 lbs./Ton of clinker at Kilns 19, 20, and 21 (KG5), or, alternatively, at those Kilns the Lafarge Companies have elected not to Retire and Replace;

    ii. Within 12 months after the conclusion of the Optimization Phase as it applies to Kilns 22 and 23 (KG6) identified in Paragraphs 13 and 7.z(1), the Lafarge Companies shall achieve and maintain compliance with the Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit for NO_x of 4.89 lbs./Ton of clinker at Kilns 19, 20, 21, 22, and 23 (KG5 and KG6), or, alternatively, at those Kilns the Lafarge Companies have elected not to Retire and Replace.

d. The Lafarge Companies shall comply with the Appendix (Control Technology Demonstration Requirements) in setting a 30-Day Rolling Average Emission Limit for NO_x applicable to each Alpena Kiln that the Lafarge Companies have not otherwise elected to Retire and/or Replace pursuant to Section VIII (Election to Retire and Replace Kilns). Within 30 Days after the establishment of a 30-Day Rolling Average Emission Limit for NO_x under the Appendix at any Alpena Kiln that the Lafarge Companies have not otherwise elected to Retire or Replace, the Lafarge Companies shall achieve and maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x at the respective Kiln.

14. Kiln Replacement Option. If the Lafarge Companies elect to Retire and Replace any Alpena Kiln in accordance with Section VIII (Election to Retire and Replace Kilns), then Paragraph 13 (Control Technology Retrofit Option) shall not apply to that Kiln. Instead, the Lafarge Companies shall:

a. Within 180 Days from the Date of Lodging of this Consent Decree, submit an application addressing all applicable requirements under the Clean Air Act and the Michigan SIP for a permit to install any Replacement Kiln(s) and thereafter take all other actions necessary to obtain such permits or approvals after filing the applications including, but not limited to, responding to reasonable requests for additional information by the permitting authority in a timely fashion, and conducting any environmental or other assessment lawfully required by the permitting authority;

b. Submit written notice to U.S. EPA and the State of Michigan pursuant to Section XIX (Notices) within ten (10) Days after the date on which the Lafarge Companies have commenced construction of the Replacement Kiln(s), stating the date on which such construction commenced;

c. Complete construction of the Replacement Kiln(s) within 42 months of the date on which the Lafarge Companies commence construction of the Replacement

Kiln(s), provided that if the Lafarge Companies fail to commence construction of any Replacement Kilns by January 1, 2012 or within 12 months of permit issuance pursuant to Paragraph 14.a., whichever is earlier, then, in addition to any other remedies available to the United States or the State of Michigan under this Consent Decree or other applicable law, the Lafarge Companies shall either:

   i. Install and Commence Continuous Operation of the Control Technology by January 1, 2014 or within 36 months of permit issuance pursuant to Paragraph 14.a., whichever is earlier, and thereafter comply with the Control Technology and other applicable requirements of Paragraph 13 as to the existing Alpena Kilns; or
   ii. Retire the Kiln(s) by July 1, 2012 or within 18 months of a permit issuance pursuant to Paragraph 14.a, whichever is earlier.

d. Commence Kiln Operation of any Replacement Kiln(s) within 42 months of the date on which the Lafarge Companies commence construction of the Replacement Kiln, or January 1, 2015, whichever is earlier;

e. Retire the Replaced Kiln(s) within 180 Days of commencement of Kiln Operation of the Replacement Kiln(s);

f. Install and Commence Continuous Operation of one SNCR at each Replacement Kiln within 42 months of the date on which the Lafarge Companies commence construction of the Replacement Kiln, or January 1, 2015, whichever is earlier; and

g. Within 180 Days after the Lafarge Companies have commenced Kiln Operation of any Replacement Kiln at Alpena, achieve and maintain compliance with a 30-

Day Rolling Average Emission Limit for NO_x of 2.1 lb/Ton of clinker, or the applicable New Source Performance Standard for NO_x for Portland Cement Manufacturing Facilities promulgated pursuant to Section 111 of the Act, whichever is more stringent, at each Replacement Kiln.

15. Subject to Paragraph 16 below, within 54 months of the date on which the Lafarge Companies commence construction of any Replacement Kiln(s), or January 1, 2016, whichever is earlier, the Lafarge Companies shall, at Alpena, achieve and maintain compliance with a Facility-Wide 12-Month Rolling Tonnage Limit for NO_x of 7,160 Tons of NO_x emitted per 12-month period.

16. Notification Regarding Alpena Replacement Compliance Dates. If a governmental entity's failure to act upon a timely-submitted or supplemented permit or approval application submitted pursuant to Paragraph 14.a., or the action of any third-party challenging the issuance of such permit operates to delay the issuance or effectiveness of a final valid permit or approval, thereby impairing the Lafarge Companies' ability to timely satisfy the implementation schedule requirements of Paragraph 14, the Lafarge Companies shall notify, in writing, the U.S. EPA and the State of Michigan of any such delay as soon as the Lafarge Companies reasonably conclude that the delay could affect their ability to comply with the implementation schedule set forth in Paragraph 14.

a. If the Lafarge Companies provide the notification required under this Paragraph 16, the Lafarge Companies shall propose in such notification, for approval by the U.S. EPA and the State of Michigan pursuant to Section XXII (Modification), a modification to the applicable schedule of implementation setting out the time necessary to comply after the permit or approval has been finalized and becomes

45. At each Kiln identified in Paragraph 7.z of this Decree (except for Joppa Kiln 3), the Lafarge Companies shall install and make operational within 12 months of the Effective Date a NO_x continuous emissions monitoring system (CEMS) at each stack which collects emissions from such Kiln (or Kilns, in the case of Ravena) in accordance with the requirements of 40 C.F.R. Part 60.

46. Except during CEMS breakdowns, repairs, calibration checks, and zero span adjustments, the CEMS required pursuant to Paragraph 45 shall be operated at all times during Kiln Operation. Each such CEMS shall be used at each Kiln to demonstrate compliance with the NO_x Emission Limits established in Section V.A (NO_x Control Technology, Emission Limits, and Tonnage Limits) and the Appendix (Control Technology Demonstration Requirements), as applicable, of this Consent Decree.

47. Each NO_x CEMS required pursuant to Paragraph 45 shall monitor and record the applicable NO_x emission rate from each Kiln stack in units of lbs of NO_x per Ton of clinker produced at such Kiln and shall be installed, certified, calibrated, maintained, and operated in accordance with the applicable requirements of 40 C.F.R. Part 60.

48. For purposes of this Consent Decree, all emissions of NO_x shall be measured by CEMS. During any time when CEMs are inoperable and otherwise not measuring emissions of NO_x from any Kiln, the Lafarge Companies shall apply the missing data substitution procedures used by the Affected State or the missing data substitution procedures in 40 C.F.R. Part 75, Subpart D, whichever is deemed appropriate by the Affected State.

VI. SO_2 CONTROL TECHNOLOGY, EMISSION LIMITS, TONNAGE LIMITS, AND MONITORING REQUIREMENTS

A. SO_2 Control Technology, Emission Limits, and Tonnage Limits.

49. Subject to Section VII (Temporary Cessation of Kiln Operation), the Lafarge

Companies shall install the SO_2 Control Technology and comply with the Emission Limits for the specific Facilities and Kilns within their system according to Paragraphs 49 through 77. The Lafarge Companies shall Continuously Operate each SO_2 Control Technology as applicable to each Kiln at all times of Kiln Operation, except for periods of Malfunction of the SO_2 Control Technology. Compliance with any requirements of this Section VI relating to any specific Facility or Kiln shall not be required if the Lafarge Companies Retire any such Facility or Kiln prior to any date for compliance. If one or more Kilns at a Facility is in Temporary Cessation, then the following provisions shall apply in addition to any other requirements in this Consent Decree:

a. The Lafarge Companies shall comply with the applicable Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit at all other Kilns not in Temporary Cessation at the Facility within 12 months of the date on which the last Optimization Phase was concluded (as determined by U.S. EPA and the Affected State) at a Kiln not in Temporary Cessation at the Facility.

b. The Lafarge Companies shall comply with the applicable Facility-Wide 12-Month Rolling Average Emission Limit and Facility-Wide 12-Month Rolling Tonnage Limit at all other Kilns not in Temporary Cessation on the dates required in this Section VI (SO_2 Control Technology, Emission Limits, Tonnage Limits and Monitoring Requirements).

Alpena

50. By January 1, 2011, the Lafarge Companies shall achieve and maintain compliance with an interim Facility-Wide 12-Month Rolling Tonnage Limit for SO_2 of 13,100 tons per year.

51. Control Technology Retrofit Option.

a. Subject to Section VII (Temporary Cessation of Kiln Operation), the Lafarge Companies shall have installed and Commenced Continuous Operation of DAA or Wet FGD technology in the table specified below on individual Kilns in the order selected by the Lafarge Companies within each specified Kiln Group ("KG") at the Alpena Facility by the dates specified below:

Kiln	Control Technology	Date of Installation and Commencement of Continuous Operation	30-Day Rolling Average Emission Limits	Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit (lbs. SO_2 /Ton of clinker)
1st Kiln in KG5	DAA	10/1/2011	*See* Appendix	3.68
2nd Kiln in KG5	DAA	11/1/2011	*See* Appendix	
3rd Kiln in KG5	DAA	12/1/2011	*See* Appendix	
1st Kiln in KG6	Wet FGD	1/1/2014	*See* Appendix	
2nd Kiln in KG6	Wet FGD	3/1/2014	*See* Appendix	

b. Upon installation of the SO_2 Control Technology, the Lafarge Companies shall Continuously Operate the SO_2 Control Technology during all times of Kiln Operation, except during periods of SO_2 Control Technology Malfunction.

c. Lafarge shall design each Wet FGD to be installed at Alpena Kilns 22 and 23 (KG6) to achieve a removal efficiency for SO_2 of no less than 90%.

d. If the Lafarge Companies elect not to Retire and Replace any Alpena Kiln in accordance with Section VIII (Election to Retire and Replace Kilns), then:

   i. Within 12 months after the conclusion of the Optimization Phase as it applies to Kilns 19, 20, and 21 (KG5) identified in Paragraphs 51 and 7.z(1), the Lafarge Companies shall achieve and maintain compliance with the Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit for SO_2 of 3.68 lbs./Ton of clinker at Kilns 19, 20, and 21 (KG5), or, alternatively, at those Kilns the Lafarge Companies have elected not to Retire and Replace;

   ii. Within 12 months after the conclusion of the Optimization Phase as it applies to Kilns 22 and 23 (KG6) identified in Paragraphs 51 and 7.z(1), the Lafarge Companies shall achieve and maintain compliance with the Demonstration Phase Facility-Wide 12-Month Rolling Average Emission Limit for SO_2 of 3.68 lbs./Ton of clinker at Kilns 19, 20, 21, 22, and 23 (KG5 and KG6), or, alternatively, at those Kilns the Lafarge Companies have elected not to Retire and Replace.

e. The Lafarge Companies shall comply with the Appendix (Control Technology Demonstration Requirements) in setting a 30-Day Rolling Average Emission Limit for SO_2 applicable to each Alpena Kiln that the Lafarge Companies have not otherwise elected to Retire and/or Replace pursuant to Section VIII (Election to Retire and Replace Kilns). Within 30 Days after the establishment of a 30-Day

Rolling Average Emission Limit for SO_2 under the Appendix at any Alpena Kiln that the Lafarge Companies have not otherwise elected to Retire or Replace, the Lafarge Companies achieve and maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 at the respective Kiln.

52. Kiln Replacement Option. If the Lafarge Companies elect to Retire and Replace any Alpena Kiln in accordance with Section VIII (Election to Retire and Replace Kilns), then Paragraph 51 (Control Technology Retrofit Option) shall not apply to that Kiln. Instead, the Lafarge Companies shall:

a. Within 180 Days following the Date of Lodging of this Consent Decree, submit an application addressing all applicable requirements under the Clean Air Act and the Michigan SIP for a permit to install any Replacement Kiln(s) at Alpena and thereafter take all other actions necessary to obtain such permits or approvals after filing the applications including, but not limited to, responding to reasonable requests for additional information by the permitting authority in a timely fashion, and conducting any environmental or other assessment lawfully required by the permitting authority;

b. Submit written notice to U.S. EPA and the State of Michigan pursuant to Section XIX (Notices) within 10 Days after the date on which Lafarge has commenced construction of the Replacement Kiln(s), stating the date on which such construction commenced;

c. Complete construction of the Replacement Kiln(s) within 42 months of the date on which the Lafarge Companies commence construction of the Replacement Kiln(s), provided that if the Lafarge Companies fail to commence construction of any Replacement Kilns by January 1, 2012 or within 12 months of permit issuance pursuant to Paragraph 52.a., whichever is earlier, then, in addition to any other remedies available to the United States or the State of Michigan under this Consent Decree or other applicable law, the Lafarge Companies shall either:

    i. Install and Commence Continuous Operation of the Control Technology by January 1, 2015 or within 48 months of permit issuance pursuant to Paragraph 52.a, whichever is earlier, and thereafter comply with the Control Technology and other applicable requirements of Paragraph 50 as to the existing Alpena Kilns; or

    ii. Retire the Kiln(s) by July 1, 2012 or within 18 months of permit issuance pursuant to Paragraph 52.a, whichever is earlier;

d. Commence Kiln Operation of the Replacement Kiln(s) within 42 months of the date on which the Lafarge Companies commence construction of the Replacement Kiln, or January 1, 2015, whichever is earlier;

e. Retire the Replaced Kiln(s) within 180 Days of commencement of Kiln Operation of the Replacement Kiln(s);

f. Within 42 months of the date on which the Lafarge Companies commence construction of the Replacement Kiln, or January 1, 2015, whichever is earlier, install and Commence Continuous Operation of Wet FGD technology designed to achieve a Control Efficiency for SO_2 of 95% at each Replacement Kiln, as compared to an identical Replacement Kiln without Wet FGD technology, at the Alpena Facility or, subject to review and approval by U.S. EPA and the Affected State pursuant to Section XI (Review and Approval of Submittals), equivalent alternative SO_2 Control Technology that may include but shall not be limited to kiln system design, which is individually or collectively designed to achieve a Control Efficiency for SO_2 equivalent to that of Wet FGD technology designed to achieve a Control Efficiency for SO_2 of 95% at each Replacement Kiln(s) at the Alpena Facility; and

g. Within 180 Days after the Lafarge Companies have commenced Kiln Operation of the applicable Replacement Kiln at Alpena, achieve and maintain compliance with a 30-Day Rolling Average Emission Limit for SO_2 of 1.4 lb/Ton of clinker, or the New Source Performance Standard for SO_2 for Portland Cement Manufacturing Facilities promulgated pursuant to Section 111 of the Act, whichever is more stringent, at each Replacement Kiln.

53. Subject to Paragraph 54 below, within 54 months of the date on which the Lafarge Companies commence construction of any Replacement Kiln(s), or January 1, 2016, whichever is earlier, the Lafarge Companies shall, at Alpena, achieve and maintain compliance with a Facility-Wide 12-Month Rolling Tonnage Limit for SO_2 of 5,762 Tons emitted per 12-month period.

54. Notification Regarding Alpena Replacement Kiln Compliance Date. If a governmental entity's failure to act upon a timely-submitted or supplemented permit or approval application submitted pursuant to Paragraph 52.a or the action of any third-party challenging the issuance of such permit operates to delay the issuance or effectiveness of a final valid permit or approval, thereby impairing the Lafarge Companies' ability to timely satisfy the implementation schedule requirements of Paragraph 52, the Lafarge Companies shall notify, in writing, the U.S. EPA and the State of Michigan of any such delay as soon as the Lafarge Companies reasonably

88. The limitations on the generation and use of netting credits or offsets set forth in Paragraphs 86 do not apply to emission reductions achieved by the Lafarge Companies that are surplus to those required under this Consent Decree ("surplus emission reductions"). For purposes of this Paragraph, surplus emission reductions are the reduction over and above those required under this Consent Decree that result from the Lafarge Companies' compliance with federally enforceable emissions limits that are more stringent than limits imposed under this Consent Decree or from the Lafarge Companies' compliance with emissions limits otherwise required under applicable provisions of the Clean Air Act or with an applicable SIP that contains more stringent limits than those imposed under this Consent Decree.

89. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by U.S. EPA or a State as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increments, or air quality-related values, including visibility in a Class I area.

90. The Lafarge Companies shall, within 30 Days after the Effective Date, apply to the State of Georgia for and upon issuance retire fifty (50) NO_x Emission Reduction Credits pursuant to Georgia's Emission Reduction Credit Rule Ga. Comp. R. & Regs. R., 391-3-1-.03(13) and the Clean Air Act. Lafarge shall thereafter provide notice to U.S. EPA of such retirement within 30 Days following receipt from the State of Georgia of confirmation of the retirement.

X. PERMITS

91. Where any compliance obligation under this Consent Decree requires the Lafarge Companies to obtain a federal, State, or local permit or approval the Lafarge Companies shall submit a timely and complete application for such permit or approval and take all other actions

necessary to obtain all such permits or approvals, allowing for all legally required processing and review including requests for additional information by the permitting or approval authority. Except as provided for in Paragraphs 16, 21, 54, and 59, the Lafarge Companies may seek relief under the provisions of Section XIV of this Consent Decree (Force Majeure) for any delay in the performance of any obligation under this Consent Decree resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if the Lafarge Companies have submitted timely and complete applications and have taken all other actions necessary to obtain all such permits or approvals and responses to requests for additional information.

92. In addition to having first obtained any required preconstruction permits or other approvals pursuant to Paragraph 91, the Lafarge Companies, within 12 months after the Commencement of operation of each Control Technology required to be installed, upgraded, or operated on a Kiln under this Consent Decree, shall apply to the Affected State to include the requirements and limitations enumerated in this Consent Decree in a construction permit or other permit or approval (other than a Title V permit) which is federally enforceable, issued under the SIP of the Affected State, and issued under authority independent of the Affected State's authority to issue Title V permits. The permit or approval shall require compliance with any applicable 30-Day Rolling Average Emission Limit, Facility-Wide 12-Month Rolling Average Emission Limit, and any applicable Facility-Wide 12-Month Rolling Tonnage Limit, and any monitoring requirements, including those in Sections V.B and VI.B. of this Decree. Following submission of the application for the permit or approval, the Lafarge Companies shall cooperate with the appropriate permitting authority by promptly submitting all information that such permitting authority seeks following its receipt of the application for the permit.

CONSENT DECREE APPENDIX
United States of America et al *v. Lafarge North America, Inc.*, et al.
Control Technology Demonstration Requirements

I. Scope and Applicability

1. The Lafarge Companies[1] shall comply with this Appendix in proposing and establishing 30-Day Rolling Average Emission Limits for Nitrogen Oxide ("NOx") and Sulfur Dioxide ("SO2") as applicable under Sections V and VI of the Consent Decree for individual kilns at Alpena, Sugar Creek, Fredonia, Joppa, Paulding, Ravena, Seattle and Tulsa (Affected Kilns).

2. The Affected Kilns include kilns of varying type, age, design and operating capacities. Raw materials employed in the Affected Kilns vary substantially. Similarly, fuels permitted and employed in the Affected Kilns vary by location and can include fuel oil, natural gas, coal, petroleum coke, tire-derived fuel, hazardous waste derived fuels, used oils and other materials beneficially reused as fuel. The Lafarge Companies shall take the following steps to establish 30-Day Rolling Average Emission Limits as required under Sections V and VI of the Consent Decree for NOx and/or SO2 at individual Affected Kilns at Alpena, Sugar Creek, Fredonia, Joppa, Paulding, Ravena, Seattle and if necessary, Tulsa:

   a. **Design Report:** The Lafarge Companies shall prepare and submit to U.S. EPA and the Affected State a Design Report for each Control Technology required under the Consent Decree for each Affected Kiln, except Sugar Creek;

   b. **Baseline Data Collection:** The Lafarge Companies shall collect baseline emission and operational data for each Affected Kiln for a 180-Day period prior to initiating operation of any Control Technology. The baseline data collection may run concurrently with other activities identified within this Appendix;

   c. **Optimization Program:** Following completion of installation of each Control Technology at each Affected Kiln, the Lafarge Companies shall, consistent with the requirements of Sections V or VI of the Consent Decree, undertake a startup and optimization program for each Control Technology;

   d. **Demonstration Program:** Upon completion of the startup and optimization program specified above, the Lafarge Companies shall operate the Control Technology in an optimized manner for a period of 12 months for the purpose of establishing a 30-Day Rolling Average Emission Limit for each Affected Kiln;

   e. **Final Report:** The Lafarge Companies shall prepare and submit to U.S. EPA and the Affected State for approval, a Final Report following completion of the 12-month period used to establish 30-Day Rolling Average Emission Limits for each Affected Kiln.

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[1] All terms in this Appendix shall be construed consistent with meanings specified in Section III, Definitions, of the Consent Decree into which this Appendix is incorporated.

Appendix 9E

St Mary’s Cement BART Technical Analysis

BART Application for Regional Haze

for

St Marys Cement Inc. (US)
Portland Cement Manufacturing Plant
Charlevoix, Michigan

December 28, 2006

Prepared By:
NTH Consultants, Ltd.
608 S. Washington Avenue
Lansing, MI 48933
(517) 484-6900
Project No. 16-060416

ST MARYS

Mr. Asadullah Khan, Senior Environmental Engineer
Michigan Dept. of Environmental Quality
AQD – Strategic Development Unit
P.O. Box 30260
Lansing, MI 48909

Dear Mr. Khan: December 21, 2006

Pursuant to your letter dated August 9, 2006, referencing the federal Regional Haze program, found at 40 CFR Part 51, Subpart P, requiring best available retrofit technology (BART), enclosed is a detailed engineering plan representing BART, as it would apply to the existing in-line kiln system located at the St Marys Cement Inc. (U.S.) (SMC) plant in Charlevoix, Michigan. The AQD had identified the in-line kiln system as a BART eligible source at SMC's plant. The deadline for submitting this plan is December 31, 2006.

The enclosed engineering plan addresses the available control technologies for particulate matter (PM), nitrogen oxides (NO_x), and sulfur dioxide (SO_2), and summarizes SMC's findings for BART, as it would apply to these air contaminants from the in-line kiln system.

SMC has recently implemented new control technologies for the in-line kiln system. These new controls consist of low-NO_x burners (identified as an indirect firing system or "IDF") for the kiln and pre-calciner, and a new state-of-the-art baghouse control device for PM routed to the main stack. The baghouse replaced the existing main stack electrostatic precipitator, and the IDF replaced the existing solid fuel firing system. These new control technologies are identified and explained further in the enclosed engineering plan.

We authorize NTH Consultants, Ltd. to serve as our agent in responding to your questions concerning the engineering plan. Should you have any questions concerning the plan, please contact them at 517-484-6900.

Sincerely,

Dirk A. Cox

Dirk A. Cox
Operations Manager

Enclosure
cc: Mr. Delbert Rector – NTH
Mr. David Ferrier – NTH
Mr. Cortney Schmidt – SMC
Fred Dindoffer, Esq., Bodman

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APPENDICES

1.0 EXECUTIVE SUMMARY

On March 27, 2006, the Michigan Department of Environmental Quality, Air Quality Division sent a letter informing St Marys Cement (SMC) that their Charlevoix facility was subject to the requirements for Best Available Retrofit Technology (BART). SMC held a subsequent meeting on June 12, 2006, with their consultant, NTH Consultants, Ltd, and the AQD to discuss the implications of being subject to the requirements of BART. A preliminary outline of the BART analysis was submitted to the MDEQ-AQD at the end of August 2006.

The emission unit identified as being subject to the BART requirements is the line kiln and pre-calciner. The AQD has identified nitrogen oxides (NO_x) and sulfur dioxide (SO_2) as the visibility-impairing pollutants of concern. SMC is including particulate matter with an aerodynamic diameter of less than 10 microns (PM_{10}) in its BART application, since this pollutant is also identified in Appendix Y (Guidance for BART Determinations) of 40 CFR Part 51.

The AQD has performed an analysis to determine whether there is a potential for SMC to have a significant impact on various Class I areas. Under EPA guidelines, BART is required if the impacts exceed 21 days per three years of greater than 0.5 deciview, which represents a 98th percentile of probability. MDEQ has used actual emissions from 2004 and 7 days per year of greater than 0.5 deciview as a basis for determining whether Michigan sources should be subject to BART. Based on the Y2003 & Y2004 actual reported emissions, the AQD determined that SMC does have an impact that exceeds the requirements for a deminimus impact of 0.5 deciview more than 7 days per year. Visibility modeling using CALPUFF showed that there are 10 days in 2002 based on potential-to-emit emissions where the impacts of PM_{10}, NO_x and SO_2 showed greater than 0.5 deciview. The highest impact was predicted to be 5.257 deciviews.

Recent CALPUFF modeling indicates that there are still visibility impacts that exceed 0.5 deciview for more than 7 days in a year, which is based on the current allowed emissions for PM, SO_2, and NO_x, in SMC's current Permit to Install, identified as No. 700-77H. PM is considered to be PM_{10} for purposes of this application.

Table 1 below describes the BART-eligible emissions unit, BART technology, affected pollutant, emission limits, averaging times, visibility improvement, and mostly affected Class I area.

Table 1 – Summary of Proposed BART

BART Emissions Unit	Proposed BART	Pollutant	BART Limit	Emissions Averaging Time	Visibility Benefit	Class I Area(s) Impacted
Kiln System	Baghouse on Main Stack	PM_{10}	0.30 lb/ton raw feed	Stack Test Protocol	None	Mostly Seney NWR
	IDF & Pre-Calciner	NO_x	6.5 lb/ton clinker	30-day rolling average	None	Mostly Seney NWR
	Alkaline exhaust gas	SO_2	4404 tons/year [1]	12-month rolling	None	Mostly Seney NWR

[1] The SO_2 emission limit is based on 8760 hours/year of continuous operation.

The remaining portion of this document demonstrates why the above technology and resulting emission limits represents BART. For NO_x, the recently installed indirect firing system (IDF) with the use of a pre-calciner represents BART. Regarding PM_{10}, SMC recently replaced the main stack ESP with a new baghouse, and the BART Guidance in Appendix Y of 40 CFR Part 51 allows the use of the MACT standard to represent BART.

SO_2 emissions are primarily attributed to the sulfur content of the raw material, not the sulfur content of the fuel. SO_2 emissions are currently much lower than the allowed rate because the limestone and shale currently being mined from the quarry have lower than historical sulfur content. The quarry still contains considerable raw material with sulfur content similar to what has been historically used. SMC cannot commit to using only the lower sulfur raw materials in the quarry, as that would greatly limit the future production capacity of the plant.

2.0 INTRODUCTION

SMC became the operator of the Charlevoix Plant on April 1, 2005, after it was purchased from CEMEX. The facility is located at 16000 Bells Bay Road, Charlevoix, Michigan, on 1300+ acres. The existing plant is a portland cement manufacturing facility that consists of quarry operations, crushing systems, raw feed receiving and storage areas, raw mill systems, fuel receiving and storage areas, a preheater/precalciner (or flash furnace), kiln, clinker cooler, clinker storage systems, finish mill systems, and a cement storage and shipping facility. The manufacture of Portland cement primarily involves crushing, grinding and blending of limestone and other raw materials into a chemically proportioned mixture which is then heated in a flash furnace (or pre-calciner) followed by a rotary kiln at extremely high temperatures (2800 degrees Fahrenheit) to produce pellets about one half to 2 inches in diameter. The pellets, known as clinker, are cooled and ground in ball mills together with 5% to 10% gypsum to produce the final product, Portland cement.

The BART eligible emission unit at SMC is the existing kiln system, which consists of the pre-calciner and horizontal kiln. The kiln system uses fuels to achieve the necessary temperature to convert raw materials into clinker. The primary fuels are coal and petcoke. The other fuels being used are propane and oil for startup purposes, and oil fuel is used in the event that solid fuels (coal and petcoke) are unavailable. The kiln system cannot operate at continuous full production when using oil fuel.

The remaining sources of NO_x and SO_2 are small heaters/boilers for hot water heating (bathrooms and showers), and cold weather heating of various buildings (such as the main office and other on-site buildings that require heating).

Nitrogen Oxides (NO_x)

NO_x are present in the flue gas in two forms: thermal NO_x and fuel NO_x. Thermal NO_x forms when nitrogen and oxygen molecules in the combustion air are disassociated at peak flame temperatures and recombined into oxides of nitrogen (primarily NO). Fuel NO_x is formed when the nitrogen in the fuel (fuel-bound nitrogen) is combined with oxygen in the combustion air to form NO_x.

Current control technologies for emissions of NO_x from cement kilns include the following:

- Selective catalytic reduction (SCR)
- Mid-kiln firing;
- Biosolids injection;
- CemStar™;
- Low NO_x burners;
- Use of a pre-calciner; and,
- Selective non-catalytic reduction (SNCR).

Selective Catalytic Reduction

Although a report published by MACTEC in 2005 identified selective catalytic reduction (SCR) as a viable option, this option has never been proven in the United States and has only one (1) application worldwide.

In a letter to the Midwest Regional Planning Organization in response to the MACTEC report titled *Cement Best Available Retrofit Technology (BART) Engineering Analysis,* the Portland Cement Association (PCA) described the use of SCR at Portland cement plants as follows:

> "Given the uncertainty in control efficiency, the still evolving application to cement kilns and excessive cost of installation and operation, SCR should not be considered as a BART (Best Available Retrofit Technology) control."

Finally, MACTEC retracted their earlier analysis saying:

> "After reviewing available literature, we agree that SCR technology has limited applicability and is not likely to be considered reasonably available or BART."

Mid-Kiln Firing

Mid-kiln firing involves modifying the horizontal kiln to accept a certain portion of the kiln's total heat input approximately half way down the kiln. This type of modification is generally done when a kiln would be firing tire-derived fuel (TDF). Literature cautions the use of mid-kiln firing for short kilns, which SMC currently operates. SMC has ruled this technology out due to mid-kiln firing being not technically feasible for SMC's short kiln.

Biosolids

Biosolids, in the form of dewatered sewage sludge, are injected into the mixing chamber of the pre-calciner, and works identical to a SNCR system. Heating of the mix with biosolids releases ammonia, which reacts with the nitric oxide (NO) from the pre-calciner to act like a SNCR unit. This requires an enormous amount of available sewage sludge. This type of control is best implemented in an area that is highly populated to provide a continuous supply of sewage sludge. Charlevoix is not a large enough metropolis to supply the necessary amounts of sludge on a continuous basis.

Introducing moisture into a cement kiln system's exhaust gas has detrimental effects due to the entrained water causing the cement-like dust to coagulate and stick to the internal equipment, which then needs to be removed causing lost production and incurring additional maintenance. This is discussed further under the NO_x and SO_2 discussions in Section 4.0. Both SNCR for NO_x control and dry flue gas desulfurization for SO_2 control involve adding a moist, or wet, reagent into the exhaust gas where the entrained cement dust becomes sticky and adheres to the internal sides of the equipment.

CemStar™

CemStar™ employs the use of iron or steel slag to reduce NO_x formation. Since the slag requires less heat input, less fuel is needed to produce clinker. Less heat input means less fuel consumption, and, therefore, less NO_x formation. Slag is also a cheaper raw material. SMC currently uses iron or steel slag in their process. Although the use of the slag requires that the chemistry of the slag be compatible as a raw material, SMC has been, and will continue to use, iron or steel slag whenever they can due to the lower energy costs for making clinker, and the cheaper cost of a raw material. However, the availability of slag is sporadic, and cannot be consistently depended upon as a continuous NO_x control technology.

Low NO_x Burners

Low NO_x burners incorporate a design feature that reduces the formation of NO_x. Through proper design and good combustion practices the formation of NO_x can be limited by controlling the peak combustion temperature, gas residence time in the peak temperature, and the air to fuel ratio. The recently installed indirect firing system (IDF) reduces the available combustion air thereby reducing the formation of NO_x in the flame zone where temperatures exist to prompt the formation of NO_x. The MDEQ-AQD recognizes the fact that an IDF system is considered to be a low NO_x burner. See Rule 801(1)(c).

Pre-Calciner Kiln System

SMC utilizes a pre-calciner system that further reduces the emissions of NO_x, as compared to other systems used in the Portland cement industry. In a typical pre-calciner kiln, almost 40 to 50 percent of the fuel is burned at a lower temperature, which reduces thermal NO_x formation.

Selective Non-Catalytic Reduction (SNCR)

SNCR involves injecting a nitrogen based compound, typically ammonia or urea solution, into the exhaust gas stream at a point where optimum temperature(s) exist to prompt the reaction of the ammonia or urea solution with the NO_x in the exhaust gas to form elemental nitrogen and water. Control efficiencies vary depending on the amount of available ammonia or urea solution, and the residence time to allow the reaction to proceed. SNCR systems are typically located in the breeching between the exhaust end of the kiln and where the exhaust gases from the kiln enter the pre-calciner. Some cement plants have incorporated the use of SNCR to control potential NO_x emissions.

Therefore, the use of using SNCR as an additional control technology is explored further in Section 4.0.

Sulfur Dioxide (SO_2)

Sulfur dioxide (SO_2) emissions are primarily determined by the content of the sulfur in the raw materials. Kilns that use raw materials with little or no volatile sulfur have relatively low SO_2 emissions. Conversely, kilns that use raw materials with larger amounts of sulfur can expect to have larger amounts of SO_2 emissions. Since this facility is located next to their own quarry, there

is little choice in the use of raw materials. However, SMC has made it a practice of selecting the lowest available sulfur content raw materials from their quarry.
Additionally, sulfur in the fuels fed to the kiln system will not lead to significant SO_2 emissions, due to the strong alkaline nature in the sintering zone, the calcination zone and in the lower stage of the preheater. Depending on the process and the source of the sulfur, SO_2 absorption, in the kiln itself, ranges from about 70 percent to more than 95 percent.

SMC also utilizes a baghouse to control the emissions at the kiln. The dust collected in this baghouse forms a highly alkaline layer on the bags further aiding the reduction of SO_2.

A study by MACTEC Engineering and Consulting, Inc. in 2005 identified advanced flue gas desulfurization (AFGD), dry FGD (or dry scrubbing), and wet FGD (or wet scrubbing) as viable control options for SO_2 emissions from Portland cement factories. Therefore, these control options will undergo further evaluation in Section 4.0.

Particulate Matter (PM)

BART for PM is not necessary according to Appendix Y of 40 CFR Part 51, because the MACT standard for Portland cement plants (40 CFR Part 63, Subpart LLL, and also known as the "Portland Cement MACT") includes a PM emission limit of 0.30 lb PM/ton of raw feed for the kiln system. The Appendix Y guidance indicates that the states can rely on the MACT standards for an affected pollutant (such as VOC and PM) to satisfy the BART requirement for that pollutant.

Nonetheless, SMC has recently replaced the main stack ESP with a state-of-the-art baghouse.

Therefore, a BART analysis for PM has not been done since SMC complies with the PM emission limit in the Portland Cement MACT.

3.0 EMISSION CONDITIONS AND VISIBILITY IMPACTS FOR THE BART-ELIGIBLE KILN SYSTEM

The following Tables 2 through 4 provides data as requested by the MDEQ-Air Quality Division. Table 2 lists the conditions for modeling input data. Table 3 contains the basis for 24-hour emissions data in Table 2. Table 4 presents the visibility modeling results.

A site plan is included in Appendix A. The CALPUFF modeling results are contained in Appendix H.

Table 2 – Modeling Input Data

Emission Unit ID	24-Hour Actual Emissions (Lbs)			Stack ID	UTM Easting Location	UTM Northing Location	UTM Zone	Stack Height[2]	Ground Elevation	Exit Diameters[1]	Exhaust Gas Flow	Exhaust Temp
	SO_2	NO_x	PM_{10}					(Feet Above Ground)	(Feet Above Mean Sea Level)	(Inches)	(ACFM)	(°F)
Kiln System	2520	1179.7	96	Main	633400	5019500	16	323	626.6	132	499,890	220
	280	131.1	10.7	Bypass	633100	5019300	16	225	626.6	78	110,700	224

[1] The stack heights and diameters have not been changed, nor will they be in the near future.

Table 3 – Basis for 24-Hour Emissions Data in Table 2

Emission Unit ID	Basis for 24-Hour SO_2 Emissions	Basis for 24-Hour NO_x Emissions	Basis for 24-Hour PM_{10} Emissions
Kiln System	Proposed BART Emissions	Proposed BART Emissions	Proposed BART Emissions

Table 4 – Visibility Modeling Results

Emission Unit ID	Class I Area with Greatest Impact	2002		2003		2004		2002-2004 Combined	
		Modeled 98th Percentile Value	No. Of Days Exceeding 0.5 Deciview	Modeled 98th Percentile Value	No. Of Days Exceeding 0.5 Deciview	Modeled 98th Percentile Value	No. Of Days Exceeding 0.5 Deciview	Modeled 98th Percentile Value	No. Of Days Exceeding 0.5 Deciview
Kiln System	Seney NWR	5.26	30	3.64	39	2.48	62	5.26	131

4.0 BART ANALYSIS FOR THE AFFECTED EMISSION UNIT (KILN SYSTEM)

Appendix Y of 40 CFR Part 51 contains the requirements for making a BART determination. This guidance identifies various sources of information when researching available control alternatives. SMC has included a copy of the results of a RACT/BACT/LAER Clearinghouse database search, and is included in Appendix E. Appendix F contains the basis for the NO_x SNCR control alternative. Appendix G contains the costs for wet and dry flue gas desulfurization (see Table IV-5 on page 4-21).

4.1 NITROGEN OXIDES (NO_x)

NO_x is one of the precursors that can cause visibility impacts at the various federally designated Class I areas. Therefore, SMC has undertaken a review of various control technologies that could be implemented to reduce NO_x emissions from their kiln system. This evaluation takes into consideration the pre-calciner and short kiln, with the control that SMC has recently implemented that includes the IDF.

Low NO_x Burners

Low NO_x burners are designed to reduce the formation of thermal NO_x. This results in early ignition, especially of the volatile compounds in the fuel, in an oxygen-deficient atmosphere, and then complete combustion is achieved with additional air later on in the combustion process. This reduces the flame temperature where NO_x is formed, which in turn reduces the formation of NO_x.

Michigan Rule 801(1)(c) recognizes the use of an IDF as meeting the requirements for a low NO_x burner. IDFs are being used by the cement industry to increase their kiln system's thermal efficiency and reduce air pollution. In November 2005, SMC submitted a permit application for a revision to Permit No. 700-77A requesting approval for the installation of the use of an IDF for their kiln. The AQD issued the permit on February 9, 2006. SMC has installed this equipment, completed a trial operation, and is currently demonstrating successful operation of this new equipment.

Furthermore, Rule 801(4)(e)(i) allows the use of a low NO_x burner in cement kiln systems to achieve reductions of NO_x emissions for the ozone control period.

Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) involves injecting ammonia or urea into the exhaust to react with NO_x to form nitrogen and water. The injection must take place at a point where the exhaust temperatures are between 1600 and 2000 °F, and has sufficient retention for the injected agents to achieve the proper reaction. SNCR results in the buildup of ammonium bisulfite scale, which is very significant for sulfur-containing raw materials and fuels. SNCR systems also appear to convert some NO to N_2O. Additionally, if the temperatures are above or below the appropriate temperature window unconverted ammonia is emitted (referred to as ammonia-slip). The ammonia that slips out can then form aerosols of ammonia chlorides and ammonia sulfates. These can become visible as a white plume above the exhaust stack.

A report in 2005 titled, *Interim White Paper - Midwest RPO Candidate Control Measures, Source Category: Cement Kilns*, from the Midwest Regional Planning Organization describes the use of SNCR by saying "SNCR technology has the potential to offer significant reductions on some precalciner kilns." In other words, there is simply not enough data at this time to warrant the use of SNCR. Furthermore, SMC currently has an SNCR system installed at their facility that has been fraught with problems, due to plugging in the breeching to the pre-calciner.

SMC uses a SNCR system to meet the requirements of Rule 801(4)(e), which is currently used to control NO_x emissions only during the ozone season. The existing SNCR causes buildup of materials inside the ductwork between the kiln and pre-calciner, which is the optimal place for the urea/NO_x reaction to occur thereby reducing NO_x emissions. This SNCR system achieves approximately 10% reduction of NO_x emissions. Whenever a wet substance, such as the liquid urea, is introduced into a cement process, it causes the cement material in the exhaust gases from the kiln to become sticky, and adheres to the sides of the ductwork between the kiln and pre-calciner. Air cannons are used to help reduce the buildup. The entire breeching would need to have many air cannons to remove the buildup that occurs along the length of the breeching. The breeching surface area is approximately 1150 square feet, and each air cannon is only effective for an approximate six square-foot area. This would mean an additional 181 air cannons to help reduce the build-up of materials on the sides of the breeching. These additional air cannons would require additional air compressor(s), which also requires additional electricity expense, and additional cooling water that would require treatment before discharge into surface waters (like Lake Michigan). The buildup reduces airflow through the kiln system, which involves eventual manually removing the buildup, and reduces production as the buildup continues. Manually removing the buildup requires the shutdown of the kiln, meaning a costly loss of one day's production. Air cannons are not entirely effective in removing all of the buildup. Therefore, installing extra air cannons would be costly and would only reduce the frequency, but not eliminate the need, for shutdowns.

The SNCR unit that is currently in place is not adequate for continuous operation, and would require the installation of another SNCR system that would be designed to achieve reliable annual service.

The cement plants that have incorporated SNCR technology also have state-of-the-art pre-calciner equipment that make the use of a SNCR system effective. EPA's RACT/BACT/LAER Clearinghouse (RBLC) (attached as Appendix E) shows which plants have the SNCR technology. Replacing the existing pre-calciner to be able to use SNCR would be extraordinarily expense, and is not considered BART.

Another issue is weather conditions. The winter weather in Charlevoix, MI experiences hard freezing temperatures that would cause solidification of the urea tank, pumps, and piping. With a 40% urea mixture, the temperature needs to be approximately 100°F to prevent the mixture from hardening. With the use of the existing SNCR during the warmer late spring/summer months, and with the heat of the kiln system, urea flow is not a problem. However, extensive heating lines would need to be installed to prevent solidification of the urea tank, pumps, and piping during the colder months of fall, winter and early spring. This results in higher installation and operating costs to install and maintain a SNCR system and keep it operating on an annual basis.

Nonetheless, a cost analysis for implementing a SNCR control system is included as Appendix B. The cost per ton of controlled NO_x is \$7,568 per ton, which is judged to be cost prohibitive to represent BART for SMC's kiln system.

Based on the above, SMC has determined that the continued use of, or replacement of, a SNCR system to achieve some control of the NO_x emissions is not feasible.

Proposed BART

SMC is proposing a BART emission limit for NO_x of 6.5 lb NO_x/ton-clinker, based on a 30-day rolling average, and represents a reduction of 15% from the current non-ozone season limit of 7.67 lb/ton clinker. A limit of 6.5 lb NO_x/ton clinker would also result in a reduction of approximately 9.5% on an annual basis. This limit would be applicable continuously, except during startups, shutdowns, and malfunctions. During startups, shutdowns and malfunctions, there is no clinker being produced that would warrant having a normalized emission limit. This emission limit is well within the accepted range of BACT determinations as found within the RBLC. SMC will attain this emission limit through the use of using iron or steel slag whenever possible, a low NO_x burner via their recently installed IDF, a pre-calciner and kiln system, and good combustion practices. For the reasons stated above, SNCR is not considered a viable option at this time. Furthermore, SMC has previously implemented SNCR at this facility and had several issues with the technology. The original intent for the SNCR was to meet the ozone season emission limit for NO_x. The SNCR was installed prior to the installation of the indirect firing system, and was necessary to reduce the NO_x emissions during the ozone season. During the non-ozone season, the SNCR was not used.

4.2 SULFUR DIOXIDE (SO_2)

SO_2 is formed from the introduction of raw materials that contain sulfur into the hot zones of the pre-calciner. SO_2 from the combustion of fuel(s) are easily absorbed into the raw materials and clinker due to their highly alkaline nature.

Portland cement plants are typically located adjacent to quarries that are used as raw material. Quarries generally vary in sulfur content depending on the location. As an example, quarries in the northern portion of the United States have higher sulfur content than those quarries in the southern portion of the United States. An individual quarry's sulfur content can also vary from seam to seam, which makes it impossible to guarantee that the raw feed will always be low in sulfur content. SMC is currently using lower sulfur raw feed from the quarry, but it cannot be assumed that the quarry will continue to provide lower sulfur content raw materials. And, as stated previously, SMC cannot guarantee that the higher sulfur raw materials will never be used.

The following discusses different SO_2 control technologies, and how they may, or may not, be used at SMC's plant to reduce SO_2 emissions.

Advanced Flue Gas Desulfurization (AFGD)

The AFGD process accomplishes SO_2 removal in a single absorber, which performs three functions: pre-quenching the flue gas, absorption of SO_2, and oxidation into gypsum.

However, as the Portland Cement Association (PCA) points out in a letter dated October 2005, this technology cannot be considered technically feasible at this time because there is a substantial lack of data demonstrating its effectiveness. In their own study, MACTEC acknowledges that there are currently no known installations of AFGD at Portland cement facilities. Furthermore, in March 2006, MACTEC responded to the PCA letter and agreed that the advanced FGD system was a U.S. Department of Energy demonstration project (*Advanced Flue Gas Desulfurization (AFGD) Demonstration Project A DOE Assessment*, August 2001) and asserted that it was questionable whether it is even technically feasible. Therefore, this technology cannot be considered a viable option for SMC.

Wet Flue Gas Desulfurization (Wet Scrubbing)

Wet FGD utilizes gas absorption technology to remove SO_2 in the waste gas. The absorbent can be a slurry of calcium carbonate, hydroxide or oxide. The slurry is injected counter current to the exhaust gas and collected in a recycle tank at the bottom of the scrubber where it is oxidized with air to form a dehydrate of calcium sulfate. Finally, dehydrate is separated and used as gypsum in cement milling and the water is returned to the scrubber.

In the United States, wet scrubbers have been demonstrated successfully in the utility industry; however, they require more care when used for a Portland cement facility. Calcium sulfate scaling and cementitious buildup occur when a wet scrubber is applied to the exhaust gas from a cement kiln. These can be avoided if these systems are installed downstream of a high efficiency particulate control device, however, any malfunction of the particulate control device can pose adverse problems for a wet scrubber. From the RBLC, only two (2) plants are currently utilizing wet scrubbers. One of the plants, Continental Cement Company, LLC, of Missouri, has an emission limit of 12 lb SO_2/ton-clinker. The other plant, Lehigh Cement Company of Iowa, has a very small emission limit, and most likely due to being a new plant.

Furthermore, wet FGD processes generate significant amounts of solid waste and require additional care for solids disposal.

A cost analysis for a wet FGD control system is contained in Appendix C. The cost per ton of controlled SO_2 is $9,258 per ton, which is judged to be cost prohibitive to represent BART for SMC's kiln system.

Dry Flue Gas Desulfurization (Dry Scrubbing)

Dry scrubbing systems spray lime slurry into an absorption tower where SO_2 chemically reacts with the lime and is absorbed by the slurry. 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 through a control device such as a fabric filter or ESP. Exhaust gases that exit at or near the adiabatic saturation temperatures can create problems with this control technology as listed below:

- Significant plugging and corrosion problems in the downstream particulate control device, duct work, and induced draft fan.
- The lime slurry would not dry properly, and it would plug up the dust collection system. Injecting an aqueous solution into the cement making process' exhaust gas stream has detrimental effects because there is cement dust in the exhaust gas. This causes the entrained cement dust to stick to the sides of the ductwork, which causes operational downtime and maintenance issues to remove the material sticking to the ductwork.

These types of issues are probably why, as of 2001, there was only one SO_2 dry scrubber in operation at a cement plant in Europe (and possibly worldwide), at the HCB-Untervaz plant in

Switzerland. Since this technology does not have a proven track record in the Portland cement industry, it cannot be considered a viable option.

Nonetheless, a cost analysis for implementing a dry FGD control system is included as Appendix D. The cost per ton of controlled SO_2 is $8,988 per ton, which is judged to be cost prohibitive to represent BART for SMC's kiln system.

Proposed BART

Due to the highly alkaline environment within the kiln, thus creating its own natural scrubbing process, SMC believes no additional controls are necessary. Furthermore, SMC already employs a method of selecting the lowest available sulfur content raw materials. While three other control options were explored, none of these options are considered to be viable options for SMC, even based on SMC's potential to emit from their most recent Permit to Install. One of these options is considered technically infeasible (AFGD), another is not economically justified (dry scrubber), and the third option would only marginally reduce the already minimal SO_2 emissions while generating solid wastes with excessive costs that do not warrant being considered BART. SMC will continue to manage the raw feed from the quarry to minimize sulfur input to the kiln system, but cannot guarantee that the quarry will continue to produce lower sulfur content materials.

BART Summary

Table 5 presents the emission rates as a result of applying BART for SMC.

Table 5 – Post-Control Emission Rates for the In-Line Kiln System

Pollutant	Control Technology	Maximum 24-Hour Emissions (lbs)	Percent Reduction
NO_x	IDF & Pre-Calciner	31,460	15.3[1]
SO_2	Use of low sulfur raw feed, as available[2]	67,200	None
PM_{10}	Baghouse on Main Stack & ESP on Bypass Stack	2,561	None

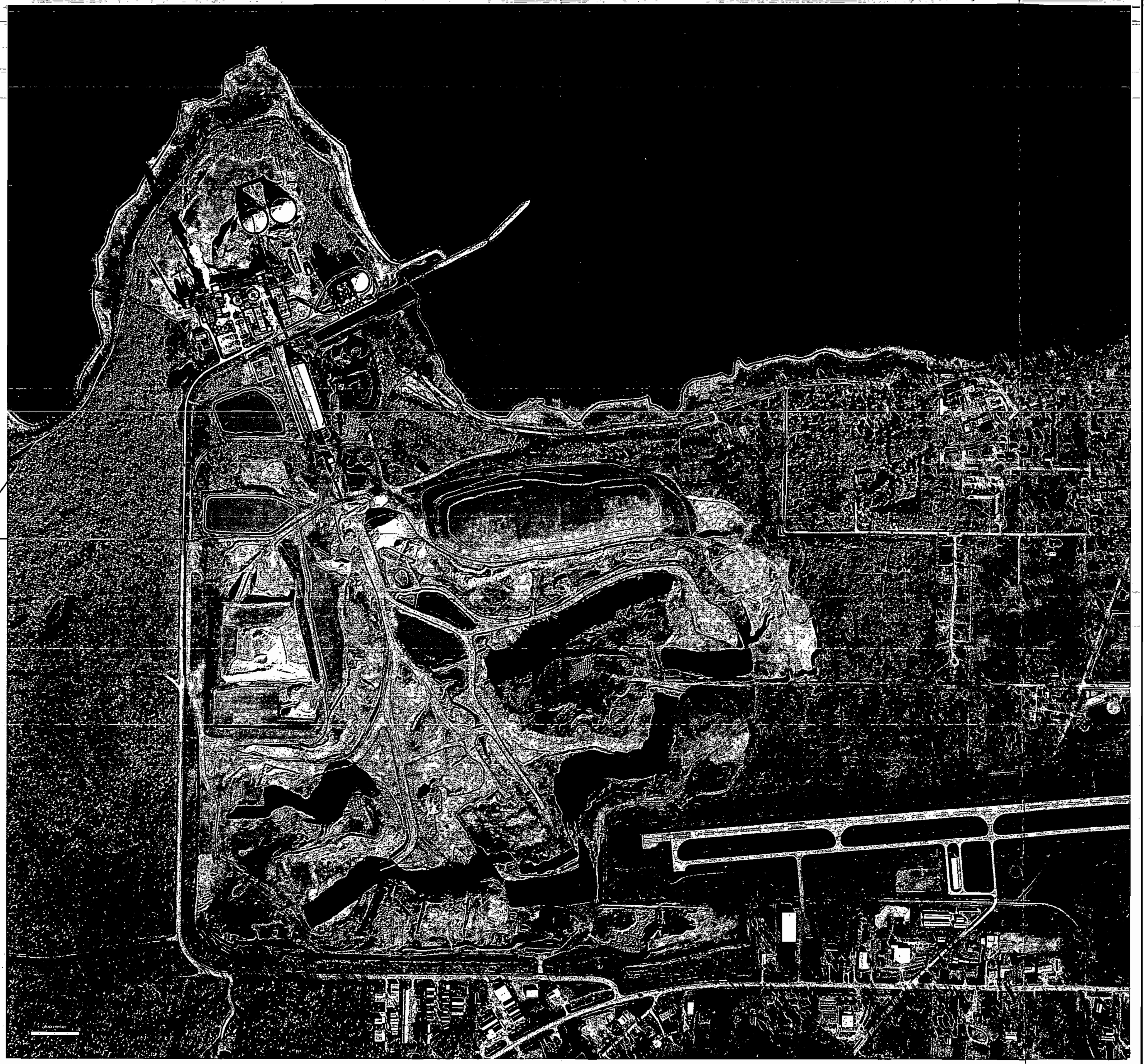
[1] This is based on a reduction from 7.67 lb NO_x/ton clinker to 6.5 lb NO_x/ton clinker.

[2] SMC will make every attempt to use lower sulfur raw materials, but cannot guarantee it at all times in the future.

APPENDIX A

Appendix A

Facility Site Map



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CEMEX INC.
CHARLEVOIX, MICHIGAN

DATE OF PHOTOGRAPHY: 11/20/2003

APPENDIX B

Appendix B

SNCR NO_x Control Cost

SNCR Cost

CAPITAL COSTS

Direct Costs			
Purchased Equipment Costs(1)			
SNCR		1.371.630	Cost is from the Environ Report contained in Appendix F. $400,000 of this is retro-fit capital to winterize the system to prevent solution freezing
Instrumentation	10% of control device cost (A)	137,163	EPA Air Pollution Control Cost Manual
Freight	5% of control device cost (A)	68,582	EPA Air Pollution Control Cost Manual
Purchased Equipment Cost. PEC (B)	21%	1,577,375	
Direct Installation Costs			
Foundations & supports	12% of purchased equip cost (B)	189.285	EPA Air Pollution Control Cost Manual
Handling & erection	40% of purchased equip cost (B)	630.950	EPA Air Pollution Control Cost Manual
Electrical	1% of purchased equip cost (B)	15.774	EPA Air Pollution Control Cost Manual
Piping	30% of purchased equip cost (B)	473.212	EPA Air Pollution Control Cost Manual
Insulation	1% of purchased equip cost (B)	15.774	EPA Air Pollution Control Cost Manual
Painting	1% of purchased equip cost (B)	15.774	EPA Air Pollution Control Cost Manual
Direct Installation Costs	85%	1,340,768	
Site Preparation, as required	Site Specific		
Buildings, as required	Site Specific		
Total Direct Costs. DC		**2,918,143**	
Indirect Costs			
Engineering	10% of purchased equip cost (B)	157,737	EPA Air Pollution Control Cost Manual
Construction and field expenses	10% of purchased equip cost (B)	157,737	EPA Air Pollution Control Cost Manual
Contractor fees	10% of purchased equip cost (B)	157,737	EPA Air Pollution Control Cost Manual
Start-up	1% of purchased equip cost (B)	15.774	EPA Air Pollution Control Cost Manual
Performance test	1% of purchased equip cost (B)	15.774	EPA Air Pollution Control Cost Manual
Contingencies	3% of purchased equip cost (B)	47.321	EPA Air Pollution Control Cost Manual
Total Indirect Costs, IC	35%	**552,081**	
Total Capital Investment = DC + IC		**3,470,224**	

SNCR Cost

ANNUAL COSTS

Direct Annual Costs, DC					
Operating Labor					
Operator	$25.38	1/2 hr per shift, 8000 hr/yr	12,690		
Supervisor	15%	of operator	1,904	EPA Air Pollution Control Cost Manual	
Operating Materials					
Reagent (Urea) 1.06 $/gal, 180 gal/hr, 8000 hr/yr, 60 lb/lbmole, 40 wt% Urea			1,440,000		
Catalyst NA -					
Maintenance					
Labor	$17.77	1/2 hr per shift, 8760 hr/yr	8,756		
Materials	100%	of maintenance labor	8,756	EPA Air Pollution Control Cost Manual	
Electricity - 0.07 $/kW-hr, 100 kW, 6570 hr/yr (for heating urea solution in cooler season)			45,990		
Clean out cementic build up on sides of ducting - 5 events/year, 1 day per event. $40/ton cement lost revenue, 4840 tpd lost cement production, $193,600 per day lost revenue.			968,000	This is based on past history of clean-out while using a SNCR for the ozone system.	
Total Direct Annual Costs, DC			**2,486,096**		
Indirect Annual Costs					
Overhead	60%	of total labor and material costs	883,264	EPA Air Pollution Control Cost Manual	
Administrative Charges	2%	of Total Capital Investment	69,404	EPA Air Pollution Control Cost Manual	
Property tax (Not allowed in Michigan)	0%	of Total Capital Investment	0	EPA Air Pollution Control Cost Manual	
Insurance	1%	of Total Capital Investment	34,702	EPA Air Pollution Control Cost Manual	
Capital Recovery 14.24% for a 10 - year equipment life and a 7% interest rate	14%		494,160		
Total Indirect Annual Costs, IC			**1,481,530**		
Total Annual Costs = DC + IC			**3,967,626**		
Pollutant Removed (tons/yr)			524	5242.9	5741 tpy (reduced to 8000 hr/yr operation) with a 10% control efficiency. 10% control efficiency is obtained from SMC, and is based on actual results.
Cost per ton of NOx removed			**$7,568**		

APPENDIX C

Appendix C

Wet FGD Control Cost

Wet Flue Gas Desulfurization Cost

Appendix C

CAPITAL COST			
Total Capital Investment (Includes all costs associated with direct equipment, engineering, freight, & ancillary costs)	**$19,132,278**	Based on $10.83 per ton of clinker. "Assessment of Control Options for BART-Eligible Sources", March 2005. See Appendix G. This cost is based on Y2002.	
ANNUAL COST			
Total Indirect Annual Costs	**$14,380,124**	Based on $8.14 per ton of clinker. "Assessment of Control Options for BART-Eligible Sources". March 2005. See Appendix G. This cost is based on Y2002.	
Total Annual Costs (Capital Cost + Annual Cost)	**$33,512,402**		
Pollutant Removed (tons/yr)	**3,620**	4021.9	4022 tpy (reduced to 8000 hr/yr operation) with a 90% control efficiency.
Cost per ton of SO_2 removed	**$9,258**		

APPENDIX D

Appendix D

Dry FGD Control Cost

Dry Flue Gas Desulfurization Cost

Appendix D

CAPITAL COST			
Total Capital Investment (Includes all costs associated with direct equipment, engineering, freight, & ancillary costs)	**$19,361,936**	Based on $10.96 per ton of clinker. "Assessment of Control Options for BART-Eligible Sources", March 2005. See Appendix G. This cost is based on Y2002.	
ANNUAL COST			
Total Indirect Annual Costs	**$9,557,306**	Based on $5.41 per ton of clinker. "Assessment of Control Options for BART-Eligible Sources", March 2005. See Appendix G. This cost is based on Y2002.	
Total Annual Costs (Capital Cost + Annual Cost)	**$28,919,242**		
Pollutant Removed (tons/yr)	**3,218**	4021.9	4022 tpy (reduced to 8000 hr/yr operation) with a 80% control efficiency.
Cost per ton of SO_2 removed	**$8,988**		

APPENDIX E

Appendix E

RBLC Search Results

RBLCID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	DTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
VA-0272	ROANOKE CEMENT	VA	ROBERT OMER	6/13/2003	CEMENT MANUFACTURING FACILITY	#5 LIME KILN - BECAUSE OF THE HIGHER ORGANIC CONTENT OF THE AVAILABLE ROCK RAW MATERIAL CAUSING GREATER CO EMISSIONS, THE CO LIMIT FROM THE #5 LIME KILN SYSTEM WAS INCREASED FROM 1296 TONS/YR TO 1950 TONS/YR. THE SHORT TERM CO LIMIT HAS NOT CHANGED. NO PHYSICAL CHANGES WERE MADE AT THE FACILITY.	LIME KILN	COAL	1300000	T/YR		NO2	GOOD COMBUSTIONS PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM	982	LB/H			BACT-PSD
SD-0003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is added to the clinker and ground to produce portland cement. Tha modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per day.	ROTARY KILN #6	CLINKER	2250	T/D	Rotary kiln #6 burns coal as a heat source. Approximately 35% of the coal is burned in the preheater/precalcinator and the remaining 65% of the coal is burned in the main burner of the kiln. The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2, CO, and NOx emission limtis will be based on continuous emission monitoring systems.	NOX	PREHEATER/PRECALCINATOR SYSTEM	2267	T/YR	5.52		BACT-PSO
SD-0003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is added to the clinker and ground to produce portland cement. The modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per	MATERIAL TRANSFER, ALKALI	CLINKER	2250	T/D	Process is alkali bypass and alkali waste to waste bin transfer. The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2, CO, and NOx emission limits will be based on continuous emission monitoring systems.	NOX		2267	T/YR	5.52		BACT-PSD
FL-0271	BRANFORD CEMENT PLANT (SUWANNE)	FL	JOE HORTON	3/30/2006	THE FACILITY IS A PORTLANT CEMENT MANUFACTURING PLANT WITH ONE LINE (KILN NO.1) AND ALL ITS ASSOCIATED CEMENT MANUFACTURING EQUIPMENT UNITS PERMITTED IN 1998. THIS PROJECT IS FOR THE CONSTRUCTION OF A NEW LINE (KILN NO.2) THAT WILL INCLUDE A CLINKER AND CEMENT HANDLING/STORAGE, COAL MILL AND COAL TRANSFER SYSTE, DRY PROCESS PREHEATER/PRECALCINER ROTARY KILN W/ AN IN-LINE RAW MILL, RAW MATERAIL HANDLING AND STORAGE. CHANGES TO THE EXISTING FACILITY WILL INCLUDE INCREASED PRODUCTION FOR THE PRIMARY CRUSHER, RAW MATERIALS PROCESSING AND INCREASED MATERIAL BEING TRANSPORTED THROUGHT OUT THE PROCESS.	THIS PERMIT IS IN THE DRAFT PHASE	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	COAL	127	T/H clinker		NOX	SNCR	1.95	LB/TON CLINKER	1.95	CEMS 30 DAYS ROLLING AVERAGE	BACT-PSO
FL-0268	BROOKSVILLE CEMENT PLANT (FCS)	FL	CHARLES ALLEN	12/20/2004	THIS FACILITY WILL CONSIST OF A PORTLAND CEMENT PLANT AND ASSOCIATED QUARRY, AND RAW MATERIAL AND CEMENT HANDLING OPERATIONS. THE PLANT WILL COMBINE RAW MATERIALS AND UTILIZE A PREHEATER/PRECALCINER KILN WITH IN-LINE RAW MILL TO PRODUCE CLINKER. THE CLINKER WILL BE MILLED AND COMBINED WITH GYPSUM TO PRODUCE PORTLAND CEMENT. THIS PROJECT IS A NEW CEMENT MANUFACTURING LINE. NEW EMISSIONS UNITS FOR THE PROJECT INCLUDE A RAW MILL SYSTEM, DRY PROCESS PREHEATER/PRECALCINER KILN SYSTEM, CLINKER HANDLING SYSTEM, FINISH GRINDING OPERATIONS, TWO CEMENT LOADOUT SILOS, AND COAL HANDLING AND GRINDING OPERATIONS.	SNCR INSTALLED FOR NOX CONTROL. NOX EMISSIONS WILL NOT EXCEED 2.4 LB/TON OF CLINKER FOR THE FIRST 180 DAYS AFTER INITIAL STARTUP. EMISSIONS LISTED IN POLLUTANT SECTION ARE FOR AFTER THE 1ST YEAR OF OPERATION.	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	COAL			KILN THROUGHPUT SHALL NDT EXCEED 2800 TON PER DAY CLINKER AND 125 TPH CLINKER	NOX	SNCR	1.95	LB/TON CLINKER	1.95	30 DAY	BACT-PSD
FL-0267	THOMPSON S. BAKER-CEMENT PLANT (FRI)	FL	CHRIS HORNER	11/5/2004	THIS FACILITY CONSISTS OF A PORTLAND CEMENT PLANT AND ASSOCIATED QUARRY, RAW MATERIAL AND CEMENT HANDLING OPERATIONS. THE PLANT WILL COMBINE RAW MATERIALS AND UTILIZE A PREHEATER/PRECALCINER KILN WITH IN-LINE RAW MILL TO PRODUCE CLINKER. THE CLINKER WILL BE MILLED AND COMBINED WITH GYPSUM TO PRODUCE PORTLAND CEMENT. THIS PROJECT IS TO ADD A NEW 125 TPH CLINKER KILN AND ALL ASSOCIATED ANCILLIARY EQUIPMENT.	SNCR ADDED FOR NOX CONTROL. NOX EMISSIONS RATE WILL BE 2.45 LB/TON CLINKER FOR THE FIRST 180 DAYS AFTER INITIAL START UP. NOX EMISSIONS LISTED IN THE POLLUTANT SECTION ARE FOR AFTER THE INITIAL YEAR AFTER STARTUP.	IN LINE KILN/RAW MILL WITH ESP AND SNCR	COAL				NOX	SNCR	1.95	LB/TON CLINKER	1.95	30 DAY	BACT-PSD
MS-0071	HOLCIM (US), INC.	MS	JAMES BOYD	8/20/2004	THIS IS A WET PROCESS CEMENT (PORTLAND) MANUFACTURING PLANT. THE PROJECT UNDER REVIEW WAS		POPRTLAND CEMENT MANUFACTURING	COAL	650000	TON CLINKER/YR		NOX	GOOD COMBUSTION PRACTICE	10	LB/T	10.00		BACT-PSD

BLCID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	OTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
IA-0070	LEHIGH CEMENT COMPANY - MASON CITY PLANT	IA	RITA DUNN	12/11/2003	PLEASE NOTE THAT A WET SCRUBBER WAS ADDED FOR BACT WHICH RESULTS IN A NET DECREASE IN PLANT EMISSIONS OF SO2 OF AROUND 5,400 TONS/YR. THE TABLE BELOW DOES NOT ALLOW NEGATIVE NUMBERS.	PROJECT NUMBER 2003-490 AND 05-282. THE PERMIT NUMBER LISTED ABOVE IS THE FACILITY'S PLANT NUMBER.	KILN/CALCINER/PREHEATER	COAL	150	T/H	Throughput is t clinker/h	NOX	SNCR, LOW NOX BURNERS, COMBUSTION CONTROLS, AND PROPER KILN DESIGN.	2.85	LB/T	2.85	LB/TON OF CLINKER	BACT-PSD
SD-0003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is edded to the clinker and ground to produce portland cement. The modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per	COAL MILL	COAL	20	T/H	The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2, CO, end NOx emission limtis will be based on continuous emission monitoring systems.	NOX	PREHEATER/PRECALCINATOR SYSTEM	2267	T/YR	5.52		BACT-PSO
AL-0203	HOLCIM (US), INC.	AL	TRAVIS OSBORNE	2/4/2003	PORTLAND CEMENT MANUFACTURING	AIRS Facility Number 01-097-08026. BACT evaluation was not performed for the kiln because it was determined that no physical or operational change was made to the kiln. This project involved: replacing the rew mill; and constructing new feed equipment for the kiln (fuel & raw materials). The new replacement equipment was more efficient than previous equipment, & resulted in increased throughput for the kiln. This triggered review for NOx and VOC for the kiln only. No new pollutant limits for the replacement equipment. Facility limits listed here are the change in emissions.	KILN SYSTEM (CALCINING KILN, PREHTR W/PRECALCINER)	COAL	390	T/H	Throughput is process capacity. Added efficiency increased throughput, and triggered review for NOx & VOC for the kiln only.	NOX		2998	T/YR	1.76		Other Case-by-Case
MD-0059	CONTINENTAL CEMENT COMPANY, LLC	MD	JERRY EPPERSON	9/24/2002	CONTINENTAL CEMENT COMPANY INTENDS TO REPLACE ITS EXISTING CEMENT KILN WITH A NEW, LARGER CAPACITY CEMENT KILN. THE NEW KILN IS DESIGNED TO INCREASE ANNUAL PRODUCTION OF CLINKER FROM 0.6 MILLION TONS TO 1.6 MILLION TONS. THE NEW OPERATIONS WILL INCLUDE A	A NET EMISSIONS INCREASE ANALYSIS WAS CONDUCTED FOR THIS PROJECT WHICH DETERMINED THAT THE NET EMISSION INCREASE FOR THE PROJECT WOULD NOT EXCEED THE SIGNIFICANT LEVEL FOR ANY AIR POLLUTANT. HOWEVER, FOR THE NET EMISSIONS INCREASE TO BE LESS THAN THE SIGNIFICANCE LEVEL, STRINGENT CONTROLS ARE MADE A PART OF THE PERMIT. THESE CONTROLS INCLUDE THE USE OF FABRIC FILTERS (FOR PM10 CONTROL), A WET SCRUBBER AND LOW SULFUR COAL FOR CONTROL OF SULFUR OXIDES, LOW-NOX BURNERS AND SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROL OF NITROGEN OXIDES, A PYROCLON (OR SIMILAR TYPE UNIT) AND A THERMAL OXIDIZER FOR CONTROL OF CARBON MONOXIDE EMISSIONS, AND A THERMAL OXIDIZER FOR CONTROL OF VOC EMISSIONS. THE CONTROLS AND RESULTANT EMISSIONS LIMITATIONS ARE SUCH THAT WE URGE OTHER AGENCIES PERMITTING	ROTARY KILN	COAL	183	T/H	Emissions from the rotary kiln and the pyroprocessing system are routed through the same controls. Thus, emission limits for the kiln and pyroprocessing system are the same. The pyroprocessing system transforms raw materials into clinker. The clinker is then introduced to the rotary kiln. The pyroprocessing system is fueled with liquid hazardous waste and coal as backup, 722.4 mmbtu/h. compliance verified by calculations.	NOX	SELECTIVE NON-CATALYTIC REOUCTION, LOW NOX BURNERS, TOP AIR OUCT.	8	LB/T	8.00	lb/t clinker, 30-day rolling avg	Other Case-by-Cese
IA-0052	LAFARGE CORPORATION	IA	SCOTT NIELSON	7/1/2002		THIS PROJECT WAS TO ALLOW THE SOURCE TO INCREASE THE CAPACITY OF ITS PREHEATER/PRECALCINER KILN SYSTEM FROM 3050 TONS OF CLINKER PER DAY TO 3488 TONS OF CLINKER PER DAY. The latest modification was fo allow waste oil as e fuel, to amend the CO BACT limit and to write a PSD permit for the clinker cooler which was not permitted under the previous project number (PN 96-464).	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	COAL	3488	T/D	COMPLIANCE WILL BE DETERMINED AFTER MODIFICATION. CEM FOR NOX, SOX AND OPACITY. KILN IS LIMITED TO USING FUEL OIL, NATURAL GAS, COAL, AND COKE AS FUELS. IN ADDITION TO CLAY AND STONE, THE KILN IS ALLOWED TO USE THE FOLLOWING SUPPLEMENTAL MATERIALS IN LIMITED QUANTITIES: COAL COMBUSTION RESIDUE, FOUNDRY BY-PRODUCTS, HYDROCARBON CONTAINING SOILS, REFINERY BY-PRODUCTS, ANO OILS AND GREASES. THERE ARE MULTIPLE POLLUTANT ENTRIES FOR TSP AND SO2 BECAUSE THEY HAVE DIFFERENT BASES FOR THEIR EMISSION LIMITS. STACK TESTING WAS	NOX	GOOD COMBUSTION PRACTICES	2546	T/YR	4.00		BACT-PSD

BLCID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	OTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
MD-0027	LEHIGH PORTLAND CEMENT COMPANY	MD	DAVID ROUSH	6/8/2000	PORTLAND CEMENT MANUFACTURING PLANT	EPA ID: 24-13-00012. LEHIGH PORTLAND CEMENT COMPANY'S UNION BRIDGE MODERNIZATION PROJECT INCLUDES THE INSTALLATION OF A 5 STAGE PREHEATER/PRECALCINER PYROPROCESSING UNIT TO REPLACE FOUR EXISTING LONG DRY KILNS. ADDITIONAL PLANT-WIDE EMISSIONS: LEAD = 0.5 T/YR; FLUORIDE = 2.0 T/YR	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	COAL	2214000	T/YR	THE PERMITS REQUIRE THE COMPANY TO CONDUCT STACK EMISSIONS TESTS AND OPERATE CEMS FOR COMPLIANCE DETERMINATION. THROUGHPUT IS CLINKER PRODUCT	NOX	A 5-STAGE PREHEATER/PRECALCINER PYROPROCESSING PLANT IS SELECTED FOR NOX EMISSION ABATEMENT. ANY ADD-ON NOX EMISSIONS CONTROL HAS BEEN DETERMINED TO BE EITHER	4871	T/YR	4.40		Other Case-by-Case
MI-0287	HOLNAM, INC.	MI	MICHELLE FERGUSON	3/20/2000	PORTLAND CEMENT PLANT.	EPA ID - MID 005038500; AIRS ID - MI 0036524; MI SRN: B1743. ACTUAL START-UP DATE IS NOT AVAILABLE. CEMENT PLANT OPERATING SINCE 1960. SINCE APPROX. 1990, WET PROCESS CEMENT PLANT HAS BEEN USING CARBON INJECTION FOR THE CONTROL OF ORGANICS. PERMIT MOD 60-71L ALLOWS FOR CESSATION OF CARBON; BAGHOUSES FOLLOWED BY SLURRY SCRUBBERS, THEN RTO. THIS POLLUTION CONTROL PROJECT IS NOT SUBJECT TO PSD, AND NOT A MAJOR MODIFICATION. THIS PERMIT SOURCE IS AUTHORIZED TO BURN TIRE CHIPS, UP TO ABOUT 21% OF HEAT INPUT, ON A PERMANENT BASIS. DURING TRIAL BURNS, UNDER EARLIER PERMIT #60-71I, STACK TESTS WERE CONDUCTED AND BECAME A BASIS FOR MUCH OF EMISSION LIMITS HEREIN.	CEMENT KILNS, WET PROCESS (2)	COAL	100	T/H FEED	MOST COMPLIANCE WILL BE DEMONSTRATED BY CEMS. AGENCY CAN INVOKE STACK TEST. CONVERSION TO PARTIAL TDF IS EXPECTED TO HAVE LITTLE EFFECT ON TOTAL PM EMISSIONS, PER APRIL 1997 TEST BURN.	NOX	CURRENT EXISTING LIMIT DOES NOT REFLECT POTENTIAL 30% REMOVAL IN SLURRY-SCRUBBER. SOME GENERATION OF NO2 BY NATURAL GAS COMBUSTION IN RTOS.	6	LB/T	6.00		Other Case-by-Case
WA-0307	PORTLAND CEMENT CLINKERING PLANT	WA		10/5/2001	MODIFICATION TO PORTLAND CEMENT PLANT PER AMENDMENTS TO ORDERS OF APPROVAL 3382 & 7381, CHANGING THE ORIGINAL PSD, AND REQUIRING AN UPDATED PSD BY PUGET SOUND CLEAN AIR AGENCY. THE MODIFICATION DELETED THE BACT LIMIT FROM THE PSD AND MOVED THE LIMIT TO A NONATTAINMENT PERMIT. THE AREA CHANGED STATUS BETWEEN INITIAL ISSUANCE OF THE PSD AND THE AMENDMENT.	INFORMATION ENTERED FOR AMENDMENT 3 OF PERMIT PSD-90-03. PLEASE REFER TO RBLC ENTRY WA-0024 FOR THE ORIGINAL PERMIT INFORMATION.	KILN EXHAUST STACK				NO FUEL OR THROUGHPUT STATED IN THE PERMIT. NO MENTION OF EMISSION LIMITS FOR PM10 IN THE PERMIT, HOWEVER IT STATED THAT PM10 WILL BE SUBJECT TO LAER	NOX	NONE INDICATED.	650	PPM @ 10% O2		24-H AV	BACT-PSD
TX-0355	PORTLAND CEMENT MANUFACTURING PLANT	TX	LARRY ALEXANDER	6/29/2001	THIS PORTLAND CEMENT MANUFACTURING PLANT USES THE DRY PROCESS AND A SINGLE KILN. THE RAW MATERIALS ARE FINELY GROUND AND BLENDED IN A DRY STATE PRIOR TO BEING FED THROUGH THE PREHEATER/CALCINER TOWER LOCATED AT THE FEED-END OF THE ROTARY CEMENT KILN. IN T	THIS PROJECT WAS SUMBITTED TO RECONCILE A PSD RETROACTIVE REVIEW FOR CO. ADDITIONAL STATE PERMITTING ACTIONS WILL INCLUDE AN AMENDMENT FOR INCREASES IN EMISSION ALLOWABLES FOR CO, VOC, HCL AND H2SO4. THERE IS NO NEW CONSTRUCTION AS A RESULT OF THIS AMENDM	GRINDING/ PREHEATING/ KILN, K-19				ADDITIONAL APPLICABLE SCC CODES: 30500622 & 30500613. EMISSION RATES FOR THE KILN ARE BASED ON A MAXIMUM CLINKER PRODUCTION OF 124 T/H. THE TWO GRINDING MILLS SHALL NOT EXCEED A PRODUCTION OF 240 T/H COMBINED OF PROCESSED MATERIAL. EMISSIONS FROM K-19 MUST COMPLY WITH NSPS SUBPART F.	NOX	NONE INDICATED	660	LB/H	2.64		Other Case-by-Case
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	BRIAN MCGILL	9/25/2000	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.6, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN		950000	T/YR	THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX	NOX	MULTI-STAGE COMBUSTION AND RECIRCULATION. EMISSION LIMIT IN LB/T OF CLINKER. LB/T LIMIT IS 12-MO ROLLING AVG.	2.32	LB/T	2.32		BACT-PSD
SD-0003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is added to the clinker and ground to produce portland cement. The modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per day	ROTARY KILN #6	CLINKER	2250	T/D	Rotary kiln #6 burns coal as a heat source. Approximately 35% of the coal is burned in the preheater/precalcinator and the remaining 65% of the coal is burned in the main burner of the kiln. The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2. CO, and NOx emission limtis will be based on continuous emission monitoring systems.	SO2	INHERENT SCRUBBING EFFECT OF PROCESSING LIMESTONE	632	LB/H	6.74		BACT-PSD

CID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	OTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
D-003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is added to the clinker and ground to produce portland cement. The modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per day	MATERIAL TRANSFER, ALKALI	CLINKER	2250	T/D	Process is alkali bypass and alkali waste to waste bin transfer. The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2, CO, and NOx emission limits will be based on continuous emission monitoring systems.	SO2	INHERENT SCRUBBING EFFECT OF PROCESSING LIMESTONE	632	LB/H	6.74		BACT-PSD
L-271	BRANFORD CEMENT PLANT (SUWANNE)	FL	JOE HORTON	3/30/2006	THE FACILITY IS A PORTLANT CEMENT MANUFACTURING PLANT WITH ONE LINE (KILN NO.1) AND ALL ITS ASSOCIATED CEMENT MANUFACTURING EQUIPMENT UNITS PERMITTED IN 1998. THIS PROJECT IS FOR THE CONSTRUCTION OF A NEW LINE (KILN NO.2) THAT WILL INCLUDE A CLINKER AND CEMENT HANDLING/STORAGE, COAL MILL AND COAL TRANSFER SYSTE, DRY PROCESS PREHEATER/PRECALCINER ROTARY KILN W/ AN IN-LINE RAW MILL; RAW MATERAIL HANDLING AND STORAGE. CHANGES TO THE EXISTING FACILITY WILL INCLUDE INCREASED PRODUCTION FOR THE PRIMARY CRUSHER, RAW MATERIALS PROCESSING AND INCREASED MATERIAL BEING TRANSPORTED THROUGHT OUT THE PROCESS.	THIS PERMIT IS IN THE DRAFT PHASE	KILN W/IN LINE RAW MILL W/ SNCR AND BAGHOUSE	COAL	127	T/H clinker		SO2	RAW MATERIALS AND PROCESS CONTROL	0.2	LB/TON CLINKER	0.20	CEMS 24-HR ROLLING AVERAGE	BACT-PSD
L-268	BROOKSVILLE CEMENT PLANT (FCS)	FL	CHARLES ALLEN	12/20/2004	THIS FACILITY WILL CONSIST OF A PORTLAND CEMENT PLANT AND ASSOCIATED QUARRY, AND RAW MATERIAL AND CEMENT HANDLING OPERATIONS. THE PLANT WILL COMBINE RAW MATERIALS AND UTILIZE A PREHEATER/PRECALCINER KILN WITH IN-LINE RAW MILL TO PRODUCE CLINKER. THE CLINKER WILL BE MILLED AND COMBINED WITH GYPSUM TO PRODUCE PORTLAND CEMENT. THIS PROJECT IS A NEW CEMENT MANUFACTURING LINE. NEW EMISSIONS UNITS FOR THE PROJECT INCLUDE A RAW MILL SYSTEM, DRY PROCESS PREHEATER/PRECALCINER KILN SYSTEM, CLINKER HANDLING SYSTEM, FINISH GRINDING OPERATIONS, TWO CEMENT LOADOUT SILOS, AND COAL HANDLING AND GRINDING OPERATIONS.	SNCR INSTALLED FOR NOX CONTROL. NOX EMISSIONS WILL NOT EXCEED 2.4 LB/TON OF CLINKER FOR THE FIRST 180 DAYS AFTER INITIAL STARTUP. EMISSIONS LISTED IN POLLUTANT SECTION ARE FOR AFTER THE 1ST YEAR OF OPERATION.	125 TPH CLINKER KILN AND ASSOCIATED EQUIPMENT	COAL			KILN THROUGHPUT SHALL NOT EXCEED 2800 TON PER DAY CLINKER AND 125 TPH CLINKER	SO2	PROCESS CONTROL AND RAW MATERIALS	0.23	LB/TON CLINKER	0.23	24-HR	BACT-PSD
L-267	THOMPSON S. BAKER-CEMENT PLANT (FRI)	FL	CHRIS HORNER	11/5/2004	THIS FACILITY CONSISTS OF A PORTLAND CEMENT PLANT AND ASSOCIATED QUARRY, RAW MATERIAL AND CEMENT HANDLING OPERATIONS. THE PLANT WILL COMBINE RAW MATERIALS AND UTILIZE A PREHEATER/PRECALCINER KILN WITH IN-LINE RAW MILL TO PRODUCE CLINKER. THE CLINKER WILL BE MILLED AND COMBINED WITH GYPSUM TO PRODUCE PORTLAND CEMENT. THIS PROJECT IS TO ADD A NEW 125 TPH CLINKER KILN AND ALL ASSOCIATED ANCILLIARY EQUIPMENT.	SNCR ADDED FOR NOX CONTROL. NOX EMISSIONS RATE WILL BE 2.45 LB/TON CLINKER FOR THE FIRST 180 DAYS AFTER INITIAL START UP. NOX EMISSIONS LISTED IN THE POLLUTANT SECTION ARE FOR AFTER THE INITIAL YEAR AFTER STARTUP.	IN LINE KILN/RAW MILL WITH ESP AND SNCR	COAL				SO2	PROCESS CONTROL AND RAW MATERIALS IN FLORIDA	0.28	LB/TON CLINKER	0.28	24 HR	
A-070	LEHIGH CEMENT COMPANY - MASON CITY PLANT	IA	RITA DUNN	12/11/2003	PLEASE NOTE THAT A WET SCRUBBER WAS ADDED FOR BACT WHICH RESULTS IN A NET DECREASE IN PLANT EMISSIONS OF SO2 OF AROUND 5,400 TONS/YR. THE TABLE BELOW DOES NOT ALLOW NEGATIVE NUMBERS.	PROJECT NUMBER 2003-490 AND 05-282. THE PERMIT NUMBER LISTED ABOVE IS THE FACILITY'S PLANT NUMBER.	KILN/CALCINER/ PREHEATER	COAL	150	T/H	Throughput is t clinker/h	SO2	WET SCRUBBER	1.01	LB/T	1.01	LB/TON OF CLINKER	BACT-PSD

LCID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	OTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
A-272	ROANOKE CEMENT	VA	ROBERT OMER	6/13/2003	CEMENT MANUFACTURING FACILITY	#5 LIME KILN - BECAUSE OF THE HIGHER ORGANIC CONTENT OF THE AVAILABLE ROCK RAW MATERIAL CAUSING GREATER CO EMISSIONS, THE CO LIMIT FROM THE #5 LIME KILN SYSTEM WAS INCREASED FROM 1296 TONS/YR TO 1950 TONS/YR. THE SHORT TERM CO LIMIT HAS NOT CHANGED. NO PHYSICAL CHANGES WERE MADE AT THE FACILITY.	LIME KILN	COAL	1300000	T/YR		SO2	LOW SULFUR FUEL, GOOD COMBUSTION PRACTICES, AND CONTINUOUS EMISSION MONITORING SYSTEM.	950	LB/H	6.40		BACT-PSD
D-003	GCC DACOTAH	SD	GENE NELSON	4/10/2003	GCC DACOTAH QUARRYS LIMESTONE, SAND, AND GYPSUM IN THE SURROUNDING AREA TO PROVIDE RAW MATERIALS FOR ITS PORTLAND CEMENT PLANT. OTHER RAW MATERIALS SUCH AS IRON AND SHALE ARE SHIPPED IN BY TRUCK FROM OTHER AREAS. COAL IS USED AS THE HEAT SOURCE AND IS SHI	GCC Dacotah owns and operates a limestone quarry and portland cement manufacturing facility in Rapid City, South Dakota. GCC Dacotah submitted a Prevention of Significant Deterioration permit application for a modification that occurred in 1996 to rotary kiln #6. Rotary kiln #6 burns coal to produce heat, which transforms limestone and other raw materials into clinker. Gypsum is added to the clinker and ground to produce portland cement. The modification increased the production capacity of rotary kiln #6 from 1,650 to 2,250 tons of clinker per	COAL MILL	COAL	20	T/H	The emission limits for NOx, SO2, and CO are for the entire kiln system. The kiln system has three emission points (1 - Rotary kiln #6, 2 - Alkali bpyass and alkali waste to waste bin transfer system, and 3 - Coal Mill) Compliance with the SO2, CO, and NOx emission limtis will be based on continuous emission monitoring systems.	SO2	INHERENT SCRUBBING EFFECT OF PROCESSING LIMESTONE	632	LB/H	31.60		BACT-PSD
L-200	CEMEX, INC.	AL	MIKE GANDY	9/13/2002	PORTLAND CEMENT MANUFACUTRING.	AIRS Facility Number: 01-091-00002 CEMEX manufactures portland cement. This facility operates one kiln system, controlled by an ESP.	KILN, CEMENT	COAL	230	T/H		SO2		160	LB/H	0.70		BACT-PSD
A-0052	LAFARGE CORPORATION	IA	SCOTT NIELSON	7/1/2002		THIS PROJECT WAS TO ALLOW THE SOURCE TO INCREASE THE CAPACITY OF ITS PREHEATER/PRECALCINER KILN SYSTEM FROM 3050 TONS OF CLINKER PER DAY TO 3488 TONS OF CLINKER PER DAY. The latest modification was to allow waste oil as a fuel, to amend the CO BACT limit and to write a PSD permit for the clinker cooler which was not permitted under the previous project number (PN 96-464).	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	COAL	3488	T/D	COMPLIANCE WILL BE DETERMINED AFTER MODIFICATION. CEM FOR NOX, SOX AND OPACITY. KILN IS LIMITED TO USING FUEL OIL, NATURAL GAS, COAL, AND COKE AS FUELS. IN ADDITION TO CLAY AND STONE, THE KILN IS ALLOWED TO USE THE FOLLOWING SUPPLEMENTAL MATERIALS IN LIMITED QUANTITIES: COAL COMBUSTION RESIDUE, FOUNDRY BY-PRODUCTS, HYDROCARBON CONTAINING SOILS, REFINERY BY-PRODUCTS, AND OILS AND GREASES. THERE ARE MULTIPLE POLLUTANT ENTRIES FOR TSP AND SO2 BECAUSE THEY HAVE DIFFERENT BASES FOR THEIR EMISSION LIMITS. STACK TESTING WAS PERFORMED FOR TSP, PM10, CO AND D/F.	SO2	DRY SCRUBBER EQUIVALENT-NOT AN ADD ON CONTROL. LIME IS GENERATED FROM LIMESTONE IN FEED AND COMES INTO CONTACT WITH SO2 AND SOME SO2 CAPTURED IN WASTE KILN DUST. ALTERNATE EMISSION LIMIT IS NAAQS. ALSO	4850	TONS/YR	7.62		BACT-PSD
D-027	LEHIGH PORTLAND CEMENT COMPANY	MD	DAVID ROUSH	6/8/2000	PORTLAND CEMENT MANUFACTURING PLANT	EPA ID: 24-13-00012. LEHIGH PORTLAND CEMENT COMPANY'S UNION BRIDGE MODERNIZATION PROJECT INCLUDES THE INSTALLATION OF A 5 STAGE PREHEATER/PRECALCINER PYROPROCESSING UNIT TO REPLACE FOUR EXISTING LONG DRY KILNS. ADDITIONAL PLANT-WIDE EMISSIONS: LEAD = 0.5 T/YR; FLUORIDE = 2.0 T/YR	CEMENT MANUFACTURING, PREHEATER/PRECALCINER KILN	COAL	2214000	T/YR	THE PERMITS REQUIRE THE COMPANY TO CONDUCT STACK EMISSIONS TESTS AND OPERATE CEMS FOR COMPLIANCE DETERMINATION. THROUGHPUT IS CLINKER PRODUCT	SO2	SO2 EMISSION CONTROL OPTIONS INCLUDE THE INSTALLATION OF A 5-STAGE PREHEATER/PRECALCINER PYROPROCESSING PLANT AND THE USE OF RAW MATERIAL WHICH CONTAINS LESS THAN 0.03%	1041	T/YR	0.94		RACT
I-287	HOLNAM, INC.	MI	MICHELLE FERGUSON	3/20/2000	PORTLAND CEMENT PLANT.	EPA ID - MID 005038500; AIRS ID - MI 0036524; MI SRN: B1743. ACTUAL START-UP DATE IS NOT AVAILABLE. CEMENT PLANT OPERATING SINCE 1960. SINCE APPROX. 1990, WET PROCESS CEMENT PLANT HAS BEEN USING CARBON INJECTION FOR THE CONTROL OF ORGANICS. PERMIT MOD 60-71L ALLOWS FOR CESSATION OF CARBON; BAGHOUSES FOLLOWED BY SLURRY SCRUBBERS, THEN RTO. THIS POLLUTION CONTROL PROJECT IS NOT SUBJECT TO PSD, AND NOT A MAJOR MODIFICATION. THIS PERMIT SOURCE IS AUTHORIZED TO BURN TIRE CHIPS, UP TO ABOUT 21% OF HEAT INPUT, ON A PERMANENT BASIS. DURING TRIAL BURNS, UNDER EARLIER PERMIT #60-71I, STACK TESTS WERE CONDUCTED AND BECAME A BASIS FOR MUCH OF EMISSION LIMITS HEREIN.	CEMENT KILNS, WET PROCESS (2)	COAL	100	T/H FEED	MOST COMPLIANCE WILL BE DEMONSTRATED BY CEMS. AGENCY CAN INVOKE STACK TEST. CONVERSION TO PARTIAL TDF IS EXPECTED TO HAVE LITTLE EFFECT ON TOTAL PM EMISSIONS, PER APRIL 1997 TEST BURN.	SO2	SULFUR IN FUEL LIMIT HAS BEEN DROPPED IN FAVOR OF CEMS. EXISTING LIMIT DOES NOT REFLECT ANTICIPATED 85% REDUCTION IN SLURRY-SCRUBBER. CONTROL BY BAGHOUSE, THEN SCRUBBER.	21.7	LB/T	21.70		Other Case-by-Case
A-307	PORTLAND CEMENT CLINKERING PLANT	WA		10/5/2001	MODIFICATION TO PORTLAND CEMENT PLANT PER AMENDMENTS TO ORDERS OF APPROVAL 3382 & 7381, CHANGING THE ORIGINAL PSD, AND REQUIRING AN UPDATED PSD BY PUGET SOUND CLEAN AIR AGENCY. THE MODIFICATION DELETED THE BACT LIMIT FROM THE PSD AND MOVED THE LIMIT TO A NONATTAINMENT PERMIT. THE AREA CHANGED STATUS BETWEEN INITIAL ISSUANCE OF THE PSD AND THE AMENDMENT.	INFORMATION ENTERED FOR AMENDMENT 3 OF PERMIT PSD-90-03. PLEASE REFER TO RBLC ENTRY WA-0024 FOR THE ORIGINAL PERMIT INFORMATION.	KILN EXHAUST STACK				NO FUEL OR THROUGHPUT STATED IN THE PERMIT. NO MENTION OF EMISSION LIMITS FOR PM10 IN THE PERMIT, HOWEVER IT STATED THAT PM10 WILL BE SUBJECT TO LAER.	SO2	DURING KILN PRE-HEATING PERIOD, SHUTDOWN, AND DURING MAINTENANCE OF THE BAGHOUSE. ONLY NAT GAS WILL BE BURNED, AND SULFUR RINGS SHALL BE REMOVED IF THE RING WAS THE CAUSE OF THE SHUTDOWN.	180	PPM @ 10% O2		1-H AV	BACT-PSD

RBLCID	FACILITY NAME	FACILITY STATE	FACILTY CONTACT	PERMIT DATE	FACILITY DESCRIPTION	OTHER PERMITTING INFORMATION	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CTRL DESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 (lb/ton of clinker)	EMISLIMIT1 AVGTIME CONDITION	CASE-BY-CASE BASIS
TX-0355	PORTLAND CEMENT MANUFACTURING PLANT	TX	LARRY ALEXANDER	6/29/2001	THIS PORTLAND CEMENT MANUFACTURING PLANT USES THE DRY PROCESS AND A SINGLE KILN. THE RAW MATERIALS ARE FINELY GROUND AND BLENDED IN A DRY STATE PRIOR TO BEING FED THROUGH THE PREHEATER/CALCINER TOWER LOCATED AT THE FEED-END OF THE ROTARY CEMENT KILN. IN T	THIS PROJECT WAS SUMBITTED TO RECONCILE A PSD RETROACTIVE REVIEW FOR CO. ADDITIONAL STATE PERMITTING ACTIONS WILL INCLUDE AN AMENDMENT FOR INCREASES IN EMISSION ALLOWABLES FOR CO, VOC, HCL AND H2SO4. THERE IS NO NEW CONSTRUCTION AS A RESULT OF THIS AMENDM	GRINDING/ PREHEATING/ KILN, K-19				ADDITIONAL APPLICABLE SCC CODES: 30500622 & 30500613. EMISSION RATES FOR THE KILN ARE BASED ON A MAXIMUM CLINKER PRODUCTION OF 124 T/H. THE TWO GRINDING MILLS SHALL NOT EXCEED A PRODUCTION OF 240 T/H COMBINED OF PROCESSED MATERIAL. EMISSIONS FROM K-19 MUST COMPLY WITH NSPS SUBPART F.	SO2	NONE INDICATED	20	LB/H			Other Case-by-Case
CO-0043	RIO GRANDE PORTLAND CEMENT CORP.	CO	BRIAN MCGILL	9/25/2000	MANUFACTURE OF PORTLAND CEMENT (DRY PROCESS)	CLINKER PRODUCTION: 950,000 T/YR; FINISHED CEMENT: 1,000,000 T/YR; COAL CONSUMED: 122,500 T/YR. RAW MATERIALS QUARRIES ADJACENT TO PLANT, CONTINUOUS EMISSION MONITOR FOR SO2, CO, NOX, CONTINUOUS OPACITY MONITORS, CEMENT KILN SUBJECT TO MACT. PLANTWIDE EMISSIONS (IN T/YR) INCLUDE: FILTERABLE PM = 155.4, PM10 FILT = 148, PM(ALL PM10) = 49.7, PM FUGITIVE = 42.7, PM10 FUGITIVE = 17.8, AND PB = 0.038. DIVISION DID NOT DETERMINE BACT EMISSION LIMIT BASED ON STANDARD UNITS. LIMITS IN STANDARD UNITS HAVE BEEN CALCULATED USING THROUGHPUT AND LB/H LIMITS.	PREHEATER/PRECALCINER, KILN		950000	T/YR	THROUGHPUT IS CEMENT CLINKER. PYROPROCESSING OF CRUDE IN A 5-STAGE PREHEATER/PRECALCINER AND CLINKERING ROTORY KILN TO PRODUCE CEMENT CLINKER. PM10 EMISSIONS ROUTED THROUGH THE KILN & CLINKER BAGHOUSE - THIS IS ENTERED AS A SEPARATE PROCESS IN THIS DETERMINATION. BACT DETERMINATIONS FOR CO, NOX, PM, PM10 AND SOX.	SO2	RAW MATERIALS QUARRY WILL BE MANAGED FOR OPTIMUM SULFUR CONTENTS. SO2 WILL BE ABSORBED IN 5-STAGE PRECALCINER/PREHEATER/KILN AND RAW MILL. EMISSION LIMIT IN LB/T OF CLINKER, 12-MO ROLLING AVG	1.99	LB/T	1.99		BACT-PSD
MO-0059	CONTINENTAL CEMENT COMPANY, LLC	MO	JERRY EPPERSON	9/24/2002	CONTINENTAL CEMENT COMPANY INTENDS TO REPLACE ITS EXISTING CEMENT KILN WITH A NEW, LARGER CAPACITY CEMENT KILN. THE NEW KILN IS DESIGNED TO INCREASE ANNUAL PRODUCTION OF CLINKER FROM 0.6 MILLION TONS TO 1.6 MILLION TONS. THE NEW OPERATIONS WILL INCLUDE A	A NET EMISSIONS INCREASE ANALYSIS WAS CONDUCTED FOR THIS PROJECT WHICH DETERMINED THAT THE NET EMISSION INCREASE FOR THE PROJECT WOULD NOT EXCEED THE SIGNIFICANT LEVEL FOR ANY AIR POLLUTANT. HOWEVER, FOR THE NET EMISSIONS INCREASE TO BE LESS THAN THE SIGNIFICANCE LEVEL, STRINGENT CONTROLS ARE MADE A PART OF THE PERMIT. THESE CONTROLS INCLUDE THE USE OF FABRIC FILTERS (FOR PM10 CONTROL), A WET SCRUBBER AND LOW SULFUR COAL FOR CONTROL OF SULFUR OXIDES, LOW-NOX BURNERS AND SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROL OF NITROGEN OXIDES, A PYROCLON (OR SIMILAR TYPE UNIT) AND A THERMAL OXIDIZER FOR CONTROL OF CARBON MONOXIDE EMISSIONS, AND A THERMAL OXIDIZER FOR CONTROL OF VOC EMISSIONS. THE CONTROLS AND RESULTANT EMISSIONS LIMITATIONS ARE SUCH THAT WE URGE OTHER AGENCIES PERMITTING CEMENT KILNS TO EXAMINE THESE	ROTARY KILN	COAL	183	T/H	Emissions from the rotary kiln and the pyroprocessing system are routed through the same controls. Thus, emission limits for the kiln and pyroprocessing system are the same. The pyroprocessing system transforms raw materials into clinker. The clinker is then introduced to the rotary kiln. The pyroprocessing system is fueled with liquid hazardous waste and coal as backup, 722.4 mmbtu/h. compliance verified by calculations.	SOX	WET SCRUBBER	12	LB/T	12.00	lb/t clinker, 3-hr rolling avg	Other Case-by-Case

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APPENDIX F

Appendix F

Final Report, Environ International Corporation, Evaluation of Potential Control Technologies for Oxides of Nitrogen from Point Sources in Ellis County, Texas, June 2004

ENVIRON

International Corporation

Air Sciences

Final Report

HARC Project H-28

Evaluation of Potential Control Technologies for Oxides of Nitrogen from Point Sources in Ellis County, Texas

Prepared for

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June 2004

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SUMMARY

INTRODUCTION

The objective of this project was to conduct a comprehensive review of all currently available technologies that could be employed for reducing NOx emissions from existing major point sources in Ellis County, Texas. Ellis County had NOx emissions in 2000 of 57 tons per day (tpd), with Point Sources contributing about 60% of those emissions. The Dallas area had 20 days over the 8-hour ozone standard in 2003, with a peak 8-hour value of 130 ppb. Because Ellis County has the potential to impact the air quality in the Dallas area, this report assesses technologies available to reduce emissions from major sources of NOx in Ellis County. The study also includes estimates for the initial capital expenditure and annual operating costs for technologies that could be practically implemented to further reduce emissions. These costs were compared with NOx controls being required of other industries and other sectors in the Dallas-Fort Worth (DFW) area.

GENERAL APPROACH

This evaluation includes an identification of the source categories that produce the largest quantities of oxides of Nitrogen (NOx) emissions from stationary point sources. To determine the potential for potential new strategies, the baseline of current control and the technical feasibility of making additional emission reductions beyond current requirements were evaluated. Within the limits of available data and information, estimates of the quantity and cost-effectiveness of these reductions are provided.

The cost estimates were based on both the capital and operating costs to achieve reductions beyond those required under current regulation. For comparative purposes, cost-effectiveness (dollars per pound of NOx reduced) was calculated. The cost-effectiveness was calculated using certification data, published data from other reports, and data from vendors and other manufacturers of emission control and process equipment. The methodologies used in this report are based on the EPA Air Pollution Control Cost Manual, Fifth Edition

The control technology and costs are compared with the level of controls and costs of NOx controls being required of other sources and other sectors in the DFW area (to the degree that such data is published and readily available).

EMISSION SOURCES

Based on a preliminary evaluation of the major sources of NOx in Ellis County, the following categories of point sources were reviewed:

Cement Kilns
Power Plants
Fiberglass Plants
Steel Industry
Glass Container Industry
Natural Gas Transmission

Due to limited resources and the need to focus on the highest priority sources, this analysis focused on the five largest facilities, which comprise most of the NOx emissions in Ellis County. Therefore, additional sources were not addressed. The 2002 emissions inventory of the TCEQ was the primary source for determining emissions from these sources[1]. Annual 2002 emissions from these five plants, based on TCEQ data[2], were as follows:

Table S-1. Summary of NOx Emissions from Cement Plants and Power Plants.

Facility	2002 NO_x (tons/yr)
Ash Grove Cement	2,572
TXI Operations	4,221
Holcim Texas	4,175
Midlothian Energy	721
Ennis Tractebel Power	89

The cement plants collectively produced more than 90% of 2002 NOx emissions from these five plants. In addition, the two power plants have advanced NOx control systems in place. The technology used for controlling NOx emissions is Selective Catalytic Reduction (SCR), which is in place on all the turbines at the two energy facilities. Accordingly, it was concluded that these plants have limited potential for further reductions. Given the limited resources for this analysis, it was decided to focus exclusively on the cement plants.

CEMENT PLANT OPERATIONS AND EQUIPMENT IN ELLIS COUNTY

There are seven wet process kilns operating in Ellis County. Three of these kilns are operated by Ash Grove Cement (formerly North Texas Cement Company) and four wet process kilns are operated by TXI Operations. Three dry process kilns are in operation in Ellis County, one at TXO Operations and two at Holcim Texas.. In the wet process kilns, slurry is introduced into the feed end but first must undergo a simultaneous heating and drying process. The wet process kilns tend to be older kilns and less conducive to methods used to control NOx emissions. The dry process kilns in Ellis County utilize a dry feed rather than a slurry and represent a newer technology referred to as preheater/precalciner kilns. These kilns have a larger capacity and have higher energy efficiency. These kilns are also more conducive to advance NOx controls.

Kilns in Ellis County have employed or propose to install a variety of controls to reduce NOx emissions. These controls include process modifications, mid-kiln firing and the installation of low-NOx burners. Process modifications, which reduce NOx emission without the installation of specific control equipment, include the ChemStar process. The processes and control equipment for reducing NOx emissions at the three cement plants in Ellis County is described in full detail in this report. Table S-2 summarizes the technologies in place and the 2002 NOx emissions from each of the kiln operations in Ellis County.

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[1] Information provided by Russell Nettles of the TCEQ Emissions Inventory group included 2002 Contaminant Summary Reports, and other detailed reports on each of the five facilities

[2] See Sections 2 and 3 for additional background on emissions estimates.

The Ash Grove Cement and TXI plants predominantly use wet process kilns. In 2002 wet process kilns, for which control options are more limited, produced about 45% of all cement plant NOx emissions.

Table S-2. Control technology used in Ellis County cement plants.

Company Name	Unit	Process	Current NOx Control Technology[4]	2002 NOx Emissions (tons/yr)
Ash Grove Cement[1]	Kiln 1	Wet Process	ChemStar, MKF (tires)[3]	823.9
Ash Grove Cement	Kiln 2	Wet Process	ChemStar, MKF (tires)[3]	829.2
Ash Grove Cement	Kiln 3	Wet Process	ChemStar, MKF (tires)[3]	918.6
Plant Total				**2,571.7**
TXI Operations, L.P.	Kiln 1	Wet Process	ChemStar, LNB	1,010.2
TXI Operations, L.P.	Kiln 2	Wet Process	ChemStar, LNB	24.3
TXI Operations, L.P.	Kiln 3	Wet Process	ChemStar, LNB	375.6
TXI Operations, L.P.	Kiln 4	Wet Process	ChemStar, LNB	988.4
TXI Operations, L.P.	Kiln 5	Dry Process[2]	LNB	1,822.7
Plant Total				**4,221.2**
Holcim Texas L.P.	Kiln 1	Dry Process[2]	LNB	1,909.7
Holcim Texas L.P.	Kiln 2	Dry Process[2]	LNB	2,265.1
Plant Total				**4,174.8**

[1] Formerly North Texas Cement Company.

[2] Precalciner Kiln.

[3] TNRCC confirmed that North Texas Cement (Ash Grove) meets the criteria of having mid-kiln firing and low NOx-burners. Letter from Richard L. Hughes, September 20, 2000.

[4] MKF is Mid-Kiln Firing, LNB is Low-NOx Burners

AVAILABILE CONTROL TECHNOLOGY AND COSTS

The evaluation of potential controls for the cement plants in Ellis County is based on the experience of other plants in the U.S. and Europe as reported in the literature. For the purposes of this report, the term "technically feasible" applies to a control method or technology has been applied to other cement kilns, has been demonstrated to be successful in reducing NOx emissions, and appears to be feasible for similar equipment and processes in use in Ellis County.

Several technologies are available to control NOx emissions from cement kilns. A full discussion of each technology is included in this analysis. Again, the purpose of this study is to guide the reader in making a “first cut” assessment of the potential for emissions reductions through the use of the technologies discussed herein, and provide some insight on next steps that may be considered.

The capital and operating costs were estimated for each of the control technologies that were deemed technically feasible in Task 3 and repeated here in Section 3. In addition, we have performed a rough estimate of the cost and cost-effectiveness of Selective Catalytic Reduction (SCR), even though it was classified as “potentially feasible”. Because the ChemStar process is used on each of the wet kilns in Ellis County, this cost of this process was not estimated. Furthermore, because low-NOx burners are used in the wet kilns at TXI Operations, the cost for this technology was also not estimated.

In order to make the analysis more relevant to the Portland Cement facilities in Ellis County, we applied various technologies to specific kilns and did so with consideration of the equipment and NO_x control methods that are already in place at each kiln. Although estimates are not provided for all technologies at each kiln, the general cost and cost-effectiveness ranges would generally apply to all kilns. The exception is where a particular technology is not applicable to a particular kiln, i.e., the application of SNCR to wet kilns. All assumptions and costs identified with this analysis are included in the cost evaluation sheets contained in Section 4 of this report.

Because this report relied on TCEQ permitting information for the facilities, some information on the costs of controls was based on assumptions that were necessary because certain information was not available from the TCEQ for the specific kilns in operation in Ellis County. For example, we were able to obtain, from TCEQ, material throughput in tons of clinker processed per year for the Ash Grove kilns and the Holcim kilns but not the kilns at TXI Operations. We were also not able to obtain information on the amount and types of fuel used for the kilns at each of the three plants. Assumptions for these parameters as well as assumptions on specific equipment such as the use of direct-fired burners at the wet kilns were also made. Further assessments should be made with facility participation, and TCEQ documented information.

Table S-3 summarizes the discussion of available control technologies as well as the costs associated with each technology.

Table S-3. Available control technologies and Costs for Cement Plants in Ellis County.

Control Technology	Kiln Type	NOx Reduction (Percent)	Capital Cost	Operating Cost	Cost-EFF ($/ton)
Mid-Kiln Firing[1]	Wet Process	28 -59	$3,228,000	(758,000)[1]	($650 - $3,685)
Bio Solids Injection[1]	Dry Process[2]	15 - 30	$947,000 - $1,246,000	($483,000)[1]- ($493,000)	($568) - ($1,325)
SNCR	Dry Process[2]	10 - 50	$3,651,000 - $3,949,000	$872,000 - $1,770,000	$1,022 - $12,197
SCR	Dry Process[2]	80 - 95	$27,685,000 - $29,773,000	$5,108,000 - $7,023,000	$3,849 - $6,696

Notes:

[1] Operating costs show a savings from tipping fees and/or fuel savings.

[2] Dry process kilns in Ellis County are all preheater/precalciner kilns.

SUMMARY

Technology for controlling NOx emissions in Ellis County is available and has the potential to significantly reduce emissions. With the exception of SCR, all the technologies identified in Table S-3 have been applied to cement plants in the U.S. It is important to note that specific technologies may not apply to a particular installation such as an older wet process kiln. Further, depending on the configuration and age of the unit, retrofit costs can increase above the costs identified in this report. With respect to SCR, this technology has been successfully applied to a specific application in Germany. A full discussion of this technology is included in this report. We have performed a rough estimate of the cost and cost-effectiveness of Selective Catalytic Reduction (SCR), even though it was classified as "potentially feasible". A technology referred to as LoTOx shows some promise, but has not been applied in a cement kiln operation. We recommend that this technology be further investigated.

This report addresses nearly all of the comments received from reviewers on the interim reports prepared for this study. However, we could not respond substantively to three specific comments because they were beyond the scope of this present project. First, comments received on the Task 2 report (Section 2 of this Report) suggested that we include the date of construction and initial startup dates for each of the cement kilns because several of the wet kilns are older configurations and less conducive to the installation of retrofit control equipment. However, that information was not available at the time of this report from the TCEQ. Second, the point was made that we should include the emission rates per ton of clinker for comparison purposes with the other clean plants in Europe. As discussed in the report, the annual clinker production was not available for all the wet kilns so we were not able to provide a comparison of the rates per ton of clinker produced. Lastly, although briefly discussed in this report, we did not investigate the issue raised by manufacturers regarding the iron ore content of the limestone, or the sulfur content of the limestone or some other aspect of the limestone which may prevent them from operating SNCR/SCR systems efficiently. Again, we did not have fuel use or fuel specification information to provide this type of analysis. We suggest that all three of these areas be further investigated. In addition, we highly recommend that any follow-on work on this project include actual site visits. This would allow onsite investigation of the operations and equipment in place as well as provide detailed information on configuration of the kilns. All of this information would provide further analyses for the TCEQ and assist in dealing with issues associated with the installation of further emission control equipment.

While this report identified potential technologies and the associated costs, it should be viewed as a preliminary evaluation to be used for further evaluation at specific sites. At this level of analysis, where detailed information on plant design, equipment and operations is not available, conclusions on technical feasibility are necessarily preliminary and have significant uncertainty. Therefore, the analysis and conclusions must be considered preliminary, since they are based on general information about the facilities in Ellis County and do not involve a detailed engineering analysis of specific plant equipment or operations. Detailed assessment of the actual emissions reductions likely from these facilities would require substantial equipment vendor interaction and plant engineering design. While we have done a preliminary engineering "scoping" assessment, including some very limited vendor discussions, this cannot replace the much more complex and costly process of actual engineering design.

Since cost-effectiveness calculations apply cost estimates to the range of emission reductions estimated in this report, all the uncertainties and limitations with emission reduction estimates that were described in the report apply equally to the cost-effectiveness numbers in this report.

At these levels of analysis, the capital cost estimates do not address specific retrofit considerations for the Ellis County plants. There was not enough information available to uncover potential hidden costs of a specific installation on a specific unit. EPA guidance notes that a retrofit factor of up to 50% of the capital cost of the control system can be justified on a case-by-case basis, but that it is also important to avoid over-estimates (Control Cost Manual, p. 2-28). Since this study has no means of developing a retrofit factor for each technology-unit combination, we have chosen to apply an across the board contingency factor of 20%. Specific considerations for retrofit requirements are identified in the discussion for each control technology. The contingency factor may or may not be adequate to cover plant and unit specific issues.

In summary, these estimates should be considered rough estimates of the actual cost-effectiveness of control should these control methods be applied to Ellis County cement plants.

1. INTRODUCTION AND GENERAL APPROACH

INTRODUCTION

Objective of Study

The objective of this study was to conduct a comprehensive review of all currently available technologies that could be employed for reducing NOx emissions from existing major point sources in Ellis County, Texas. Ellis County had NOx emissions in 2000 of 57 tons per day (tpd), with Point Sources contributing about 60% of those emissions. The Dallas area had 20 days over the 8-hour ozone standard in 2003, with a peak 8-hour value of 130 ppb. To address this problem, we evaluated technologies available to reduce emissions from major sources of NOx in Ellis County. The study includes an analysis of current control methods to reduce NOx emissions as well as estimates for the initial capital expenditure and annual operating costs for technologies that could be practically implemented to further reduce emissions. These costs are compared with NOx controls being required of other industries and other sectors in the Dallas-Fort Worth (DFW) area.

Definition of the Problem

Ozone is created in the atmosphere by the chemical reaction of reactive organic gases (ROG) and oxides of nitrogen (NOx). The Dallas/Fort Worth (DFW) area Consolidated Metropolitan Statistical Area (CSMA) consists of 12 counties: Denton, Collin, Dallas, Tarrant, Johnson, Ellis, Kaufman, Parker, Rockwall, Hunt, Hood, and Henderson. Four of these counties (Denton, Collin, Dallas, and Tarrant) are nonattainment for the one-hour ozone standard. The DFW area is classified as a "serious" ozone nonattainment area by the Environmental Protection Agency (EPA) for the one-hour standard. The DFW portion of the SIP was adopted by the Texas Commission on Environmental Quality (TCEQ) in April 2000. EPA proposed to approve the SIP in January 2000, but several key funding and court decisions since that time have prevented full approval of the SIP. The court decision also affected the decision to extend until November 15, 2007 the deadline to attain the one-hour ozone standard. EPA has however, approved 13 of the 19 TCEQ rules implementing the 2000 SIP. In July 2003, TCEQ submitted to EPA its proposal for the boundaries of a new 8-hour ozone standard nonattainment area, which included seven counties of the CMSA. EPA has since responded that it believes the entire 12 county CMSA should form the 8-hour nonattainment area. A final decision will be made by April 15, 2004. Meanwhile, TCEQ is working on an early 8-hour SIP and mid-course review to check progress toward attainment. A proposed SIP is tentatively scheduled for April 2004 and the final in October 2004. It is for this early 8-hour, transitional SIP that this Ellis County NOx emission inventory and control measure evaluation is being developed.

As part of this SIP, the importance of local NOx reductions as well as the transport of ozone and its precursors from the Houston/Galveston area were taken into account. According to the projected inventory, the four county DFW ozone non-attainment area will emit 501 tons per day (tpd) of NOx by 2007, not counting the necessary control strategy reductions. In order to reach the attainment goal of 321 tpd, the four-county area will have to reduce NOx by 180 tpd. Additional reductions of about 49 tpd from nine neighboring counties in the CSMA will contribute towards attainment.

On March 5, 2003, the TCEQ adopted further changes to the DFW portion of the SIP which included revisions to the NOx control strategy for cement Kilns in DFW. As noted above, the next major SIP submittal for the DFW area will be for the mid-course review in 2004. This mid-course review will involve an evaluation of all modeling, inventory data and other tools to develop the attainment demonstration. Re-evaluation of existing control measures and, if needed, adoption of new strategies will also occur during the mid-course review.

GENERAL APPROACH

The first task was to identify the source categories that produce the largest quantities of oxides of Nitrogen (NOx) emissions from stationary point sources. Second, the baseline of current control levels were determined. Third, we evaluated the technical feasibility potential of making additional emission reductions beyond current requirements. Fourth, within the limits of available data and information, we provide estimates of the quantity and cost-effectiveness of these reductions. These costs include both initial capital costs and operating costs. Throughout this study, we coordinated with the Houston Advanced Research Center (HARC) and the Texas Commission on Environmental Quality (TCEQ) at each stage. Information for the study was obtained from numerous sources including the Air Permits and Technical Analysis Divisions of the TCEQ, regulators other states, regulators from Europe, control equipment vendors as well as information from numerous reports, emission tests and data from sources in Ellis County and other areas.

For each of the categories discussed below, there are several elements of the analysis that are common to the evaluation. These two categories are the Evaluation of Cost, and the Comparison of Emissions and Cost to Other Sources in the DFW area.

Evaluation of Cost

The cost estimates were based on both the capital and operating costs to achieve reductions beyond those required under current regulation. The local regulatory authorities were consulted to obtain information of regulatory requirements, the status of their implementation, and information on individual sources. For comparative purposes, cost-effectiveness (dollars per pound of NOx reduced) are calculated. The cost-effectiveness was calculated using certification data, published data from other reports, and data from vendors and other manufacturers of emission control and process equipment.

Comparison of Emissions and Cost to Other Sources in the DFW Area

To place the N0x controls and cost in perspective, the control technology and costs are compared with the level of controls and costs of NOx controls being required of other sources and other sectors in the DFW area (to the degree that such data is published and readily available).

EMISSION SOURCE CATEGORIES

Based on a preliminary evaluation of the major sources of NOx in Ellis County, we identified the following categories of point sources to evaluate: It should be noted that the list is identified in the order of priority that our evaluations were conducted.

Cement Kilns
Power Plants
Fiberglass Plants
Steel Industry
Glass Container Industry
Natural Gas Transmission

According to the current TCEQ emissions inventory (2001 updates for point sources) the categories identified above produce the largest quantities of oxides of Nitrogen (NOx) emissions from stationary point sources in Ellis County. Five (5) specific facilities account for 96% of the point source emissions in Ellis County. The goal of this study was to evaluate the technical feasibility potential of making additional emission reductions beyond current requirements.

EVALUATION OF POINT SOURCE CATEGORIES

The following discussion presents an overview of the background and technical approach used to evaluate NOx emissions associated with each emission inventory category listed above.

Cement Kilns

Three large cement plants are located in Ellis County. These three plants (TXI Midlothian, Holcim Midlothian, and NTCC Midlothian) are all located within a few square miles of each other and comprise the single largest source of NOx emissions in North Texas. There are a total of 10 kilns in operation at these three plants. Because of the magnitude of the emissions, and the proximity of the emissions to the DFW current non-attainment region, considerable public debate has centered on this emissions category and these sources.

Existing Emissions

Based on the year 2002 Emissions Inventory, the Ellis County cement plants emitted nearly 11,000 tons of NOx. The specific emissions are as follows:

North Texas Cement Company – 2,572 tpy
TXI Operations – 4,221 tpy
Holcim Texas – 4,175 tpy

We evaluated the current emissions from each of the three cement plants. The emissions inventory of the TCEQ was the primary source for determining emissions from these cement plants. Information provided by the TCEQ included specific information about each source including specific current emissions, facility operating conditions, fuel use, emission abatement devises and material throughput. In addition, we obtained all current permits and any written permit conditions on the operation of each facility. In addition, we obtained from TCEQ, a copy of any emission source test results that were available from some operations.

In addition to facility emissions, we also reviewed the control requirements currently in place by reviewing the current TCEQ regulations and federal requirements that are applicable to these sources. This included all recently adopted regulations. Information was also obtained from the TCEQ on individual sources, including emission rates, the type of fuel and equipment in use, installed control equipment, other information related to the level of control that is currently in place and the operating factors (amount of time the source operates on an annual basis).

Evaluation of Available Control Technology

Once the baseline control requirements for priority categories was established, we determined whether additional emission reductions are technically feasible and could be made cost-effectively. Several technologies are available to control NOx from cement kilns. These include the application of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) technologies. In addition, we looked at other technologies that are currently in use at cement kilns in the U.S and Europe. Our analysis included a review of available documents from other states and control agencies with air quality problems. States such as Iowa, Florida, New York, Missouri and California, which have recently permitted or are in the process of permitting cement kilns provided valuable information in evaluating the potential for additional NOx controls in Ellis County.

ENVIRON has completed numerous studies for the TCEQ and regional planning areas in Texas that will contain useful information on control measure effectiveness. Areas that have been evaluated include North Central Texas, Tyler-Longview-Marshall, and the Houston-Galveston region. We also plan to examine recent development efforts in Texas related to cement kiln emissions technology assessments.

Technical References

The following sources of information were used for this evaluation:

1. 2002 Emissions Inventory Guidelines, Technical Analysis Division, Texas Commission on Environmental Quality, December 2002.
2. Emissions Inventory Forms for Specific Cement Kilns, Texas Commission on Environmental Quality, Russell Nettles, and TCEQ.
3. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP-42 Fifth Edition, January 1995 and subsequent updates, United States Environmental Protection Agency.
4. Applicable Permits for Specific Cement Kilns, Texas Commission on Environmental Quality, Randy Hamilton, TCEQ.
5. New Developments of High Dust-SCR technology in the cement industry Results of pilot tests in Solnhoffen and development stat of full-scale SCR unit, Norbert Haug, Federal Environmental Agency, Berlin Germany.

6. Reduction of nitrogen oxides with SNCR technology at Slite cement plant, Per Junder, Swedish Environmental Protection Agency, Sweden.
7. Integrated Pollution Prevention and Control (IPPC), Reference Document on Best Available Techniques in the Cement and Lime Manufacturing Industries, March 2000, European Commission, Technologies for Sustainable Development European IPPC Bureau.
8. The Pending Permit Application for St. Lawrence Cement, New York.
9. Dallas-Fort Worth Attainment Demonstration SIP Emission Reduction Control Strategies.
10. Analysis of Emission Reduction Control Measures for Attaining the 8-Hour Ozone NAAQS in the Tyler/Longview/Marshall Near Nonattainment Area, ENVIRON International Corporation, September 9, 2002.
11. Evaluation of Attainment Control Strategies for the Dallas-Fort Worth State Implementation Plan, ENVIRON International Corporation, October 2000.
12. Air Quality Planning Documents, for the South Coast Air Quality Management District (SCAQMD), the Ventura County Air Pollution Control District and the San Joaquin Valley Unified Air Pollution Control District, California.
13. Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies and Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.
14. AirControlNET, A Control Strategy and Costing Tool, E.H. Pechan & Associates, October 2003.
15. Manufacturers test data or product information.
16. U.S. EPA Reasonably Available Control Technology (RACT) documents and Control Technology Guidance (CTG) documents.
17. California Air Resources Board (CARB) Best Available Control Technology/Best Available Retrofit Control Technology (RACT/BARCT) documents.
18. Standards identified by CARB as "Achievable Performance Standards."
19. Environmental Protection Agency, Acid Rain Database for NOx, BACT/LAER Guidelines.
20. Individual Experts Contacted:

    - Tom Lugar, KWH Catalysts, Inc.
    - Chris Roling, Iowa Department of Natural Resources
    - Al Linero, Florida Department of Environmental Protection
    - Joe Hower, ENVIRON Corporation
    - Anne McQueen, ENVIRON Corporation

Power Plants

Two power plants are located in Ellis County that are major sources of NOx. These two plants (Midlothian Energy and Ennis Tractebel) employ simple cycle gas turbines and combined cycle gas turbines to generate electricity.

Existing Emissions

Based on the year 2002 Emissions Inventory, the Ellis County these two plants had the following emissions:

Midlothian Energy – 721 tpy
Ennis Tractebel – 89 tpy

The NOx emissions for Ennis Tractebel were zero in the year 2000/2001, as this plant only came on line a year and a half ago. The ENVIRON team evaluated the current emissions from each of the two power plants. The emissions inventory and operating permits from TCEQ were the primary source for determining emissions from these sources. Information provided by the TCEQ included specific information about each source including specific current emissions, facility operating conditions, fuel use, emission abatement devises and material throughput.

In addition to facility emissions, we also reviewed the control requirements currently in place by reviewing the current TCEQ regulations and federal requirements that are applicable to these categories. This included all recently adopted regulations as well as emission rates, the type of fuel and equipment in use, installed control equipment, other information related to the level of control that is currently in place and the operating factors (amount of time the source operates on an annual basis).

Evaluation of Available Control Technology

Once the baseline control requirements for these two plants was established, we evaluated whether additional emission reductions are technically feasible and can be made cost-effectively. Several technologies are available to control NOx from power plants. Turbines that are currently controlled with Dry Low NOx Combustors (DLNC) can achieve an additional 20% control by the additional application of Selective Catalytic Control (SCR). SCR control techniques have been widely used in simple cycle gas turbines and almost exclusively in combined cycle gas turbines. However SCR retrofits will often require the use of additional space at a facility for control equipment and support equipment, such as ammonia storage tanks. There are many applications of SCR for both oil and gas fired units operating successfully in the U.S. and elsewhere in the world. Reductions of 85 percent to 90 percent are achievable. Again, add-on control equipment can sometimes be difficult depending on the space limitations at a given facility, or at a given unit. To make this determination, we conducted a review of available documents from other states and control agencies with air quality problems. Regulations that are currently in place in many areas of California and elsewhere with severe air quality problems also provide information on the potential for reductions of NOx emissions beyond that required in Ellis County. The air quality planning documents include those for the South Coast Air Quality Management District (SCAQMD), the Bay Area Air Quality Management District (BAAQMD), the Ventura County Air Pollution Control District, and the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). One of the key sources of information is a compilation of RACT/BACT/LAER in California as well as a review of the Best Available Retrofit Control Technology (BARCT) documents developed by California Districts, ARB and the EPA (including that addressed through the U.S. EPA AirControlNET).

Technical References

The following sources of information were used for this evaluation:

1. 2002 Emissions Inventory Guidelines, Technical Analysis Division, Texas Commission on Environmental Quality, December 2002.
2. Emissions Inventory Forms for Specific Power Plants, Texas Commission on Environmental Quality, Russell Nettles, TCEQ.
3. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, AP-42 Fifth Edition, January 1995 and subsequent updates, United States Environmental Protection Agency.
4. Applicable Permits for Specific Power Plants, Texas Commission on Environmental Quality, Randy Hamilton, TCEQ.
5. Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, September 1999.
6. Guidance for the Permitting of Electrical Generation Technologies, California Air Resources Board, July 2002.
7. Regulation to Establish a Distributed Generation Certification Program, California Air Resources Board, September 2001.
8. Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies and Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.
9. Dallas-Fort Worth Attainment Demonstration SIP Emission Reduction Control Strategies.
10. Analysis of Emission Reduction Control Measures for Attaining the 8-Hour Ozone NAAQS in the Tyler/Longview/Marshall Near Nonattainment Area, ENVIRON International Corporation, September 9, 2002.
11. Evaluation of Attainment Control Strategies for the Dallas-Fort Worth State Implementation Plan, ENVIRON International Corporation, October 2000.
12. Air Quality Planning Documents, for the South Coast Air Quality Management District (SCAQMD), the Ventura County Air Pollution Control District and the San Joaquin Valley Unified Air Pollution Control District, California.
13. AirControlNET, A Control Strategy and Costing Tool, E.H. Pechan & Associates, October 2003.
14. Manufacturers test data or product information.
15. U.S. EPA Reasonably Available Control Technology (RACT) documents and Control Technology Guidance (CTG) documents.
16. California Air Resources Board (CARB) Best Available Control Technology/Best Available Retrofit Control Technology (RACT/BARCT) documents.
17. Standards identified by CARB as "Achievable Performance Standards."
18. Environmental Protection Agency, Acid Rain Database for NOx, BACT/LAER Guidelines.

OTHER NOx EMISSION SOURCES IN ELLIS COUNTY

The focus of this study was the three cement plants and two major power plants. These five plants comprise, by far, most of the NOx emission in Ellis County. Because of this, and because we wanted to expend analytical resources for this study with productively, additional sources were not addressed at that same level of detail. Following is a summary of these sources, the NOx emissions from these sources and an identification of potential NOx control methods. Additional assessment may be warranted to determine, especially in light of the ozone attainment challenge, if emissions reductions from these sources is cost effective.

Fiberglass

This category includes facilities that manufacture fiberglass for insulation and other purposes. Ellis County has one major facility in this category: the Owens-Corning Waxahachie Plant. This plant includes a glass melting furnace, curing oven, facing oven and other associated equipment used in the fiberglass manufacturing process such as fiberizing and forming equipment, incinerators and boilers. Most of this equipment is fired with natural gas.

Owens-Corning Wazahachie Plant – 580 tpy

Operations that result in emission of NOx include the furnace associated with the fiberglass forming and the curing oven to drive off moisture and cure the binders. Several technologies are available to control NOx from fiberglass plants. These include the use of natural gas for the furnaces and ovens as well as low-NOx burners in the ovens and boilers.

Steel

There is one major source of NOx emissions from the steelmaking process. This is the Chaparral Steel Midlothian facility. This facility employs an electric arc furnace (EAF), which is used to produce carbon and alloy steels. Several furnaces are used including two bar mill reheat furnaces, a medium section mill reheat furnace, a large section mill reheat furnace and well as other miscellaneous combustion sources.

Chaparral Steel Midlothian – 490 tpy

1. There are not a lot of options available to control NOx from electric arc furnaces. To determine the potential for further control of these sources would require an analysis similar to the analysis conducted for cement plants and power plants.

Glass Container

Saint Gobain Containers is the only major facility in this category. The Saint Gobain plant is a glass container manufacturer. This facility uses three annealing ovens, a distributor mold preheat ovens and a glass-melting furnace all fired on natural gas.

Saint Gobain Containers – 334 tpy

The procedures for manufacturing glass are the same for all products (flat glass, container glass, and pressed and blown glass) except for forming and finishing. Container glass use pressing, blowing or pressing and blowing to form the desired product. The furnace most commonly used in a continuous regenerative furnace capable of producing 50 to 300 tons per day. The melting furnace contributes over 99 percent of the total emissions from a glass plant, both particulates and gaseous pollutants. Nitrogen oxides are formed as a product of combustion in the high temperature furnace. To determine the potential for further control of these sources would require an analysis similar to the analysis conducted for cement plants and power plants.

Natural Gas Transmission

The TXU Lone Star Pipeline Company operates a natural gas pipeline compressor station in Ellis County. According to the 2000 Emissions Inventory this was the only natural gas transmission facility in Ellis County that is considered a major source. The facility includes a natural gas fired gas turbine; a standby reciprocating engine fired on either distillate oil or diesel fuel and on compressor.

TXU Lone Star Pipeline Company – 54 tpy

Several technologies are available to control NOx from gas turbines and Internal Combustion engines used at compressor stations. Turbines that are currently uncontrolled can employ Dry Low NOx Combustors (DLNC) Selective Catalytic Control (SCR). There are many applications of SCR for both oil and gas fueled units operating successfully in the U.S. and elsewhere in the world. Reductions of 85 percent to 90 percent are achievable.

2. CURRENT CONTROL BASELINE

INTRODUCTION

This section describes the second task of this project to conduct a review of all currently available technologies that could be employed for reducing NOx emissions from existing point sources in Ellis County, Texas. Ellis County had NOx emissions in 1999 of 57 tons per day (tpd), with Point Sources contributing about 53% of those emissions. The remainder are from area sources and mobile sources (on and off-road).

The elements deemed necessary for the project are as follows:

- identify and prioritize the source categories that produce the largest quantities of oxides of Nitrogen (NOx) emissions from stationary point sources
- characterize the baseline of current control levels for prioritized sources
- evaluate the potential of making additional emission reductions beyond current requirements
- within the limits of available data and information, we provide estimates of the quantity and cost-effectiveness of these reductions
- coordinate with and report to the Houston Advanced Research Center (HARC) and the Texas Commission on Environmental Quality (TCEQ) at each stage.

The purpose of this section is to describe the establishment of a baseline of information from which we could determine the potential additional reductions of oxides of nitrogen (NOx) that could be obtained in Ellis County. To perform this task, we reviewed information provided by the TCEQ for each major source in the highest priority categories. The categories identified as the highest priority were based on our preliminary evaluation (reported in our Part 1 memo report of January 15, 2004) of the major sources of NOx emissions in Ellis County. Table 2-1 provides the emissions associated with the major sources for the year 2001.

Table 2-1. Major Sources of NOx[1,2]

Company	SIC Code	2001 NOx Emissions TPY	2002 NOx Emissions TPY
Chaparral Steel Midlothian	3312	478.64	489.6
Koral Industries	3312	0	0
Elk Corporation of Texas	2952	25.7	25.7
G.S Roofing Products	2952	3.0	2.8
Ash Grove Cement Company	3241	2,922.9	2571.7
Saint Gobain Containers	3221	303.2	334.3
Owens-Corning, Waxahachie Plant	3296	574.4	580.4
TXI Operations	3241	4,444.4	4221.2
Holcim Texas, LP	3241	3,078.1	4174.8
Owens Corning	2952	10.8	10.2
DARTCO of Texas, LP	3089	21.4	22.2
TXU Lone Star Pipeline Co	4922	29.6	54.2
Waste Management of Texas	4953	3.4	8.0
Midlothian Energy	4911	387.3	721.1

Company	SIC Code	2001 NOx Emissions TPY	2002 NOx Emissions TPY
Total (TPY)		12,282.8	13,216.2

[1] From TNRCC Point Source Emission Inventory. Note that Major Sources are defined as 25 tons per year of either NOx or VOC. Accordingly; major sources of VOC may have emissions less than 25 tons per year of NOx.
[2] The Ennis Tractebel EGU (SIC Code 4911) had 2001 NOx emissions 0 TPY.
This is the other power plant in Ellis County but did not come on until June 2002, and thus is not reflected in the above 2001 emissions. All emissions estimates, and resulting prioritizing of work, will be re-addressed under Tasks 1 and 2.

Based on the information from Table 2-1, the following categories of point sources (in priority order) were identified:

Cement Kilns
Power Plants
Fiberglass Plants
Steel Industry
Glass Container Industry
Natural Gas Transmission

Based on the TCEQ emissions inventory for 2001, five (5) specific facilities (three cement plants and 2 power plants) account for 96% of the point source emissions in Ellis County. Thus, the principal goal under this task was to evaluate the technical feasibility potential of making additional emission reductions beyond current requirements with a priority to address these five facilities.

Specific information was provided by the TCEQ on current emissions (2002), facility operating conditions, fuel use, emission abatement devises and material throughput[1]. In addition, we evaluated current permits as well as written permit conditions on the operation for each facility. To establish the baseline also requires an identification of the control requirements currently in place on the highest priority source categories. This required a review of the current TCEQ regulations and federal requirements that are applicable to these categories as well as recently adopted regulations.

We evaluated the current emissions from each of the three cement plants and the two major power plants. The 2002 emissions inventory of the TCEQ was the primary source for determining emissions from these sources[2]. As indicated earlier, these five largest facilities comprise, by far, most of the NOx emissions in Ellis County. Because of this, and because we want to expand analytical resources in this project with productivity, additional sources were not addressed under this task. As time and resources permit, these additional sources will, however, be reviewed again to determine if further reduction of NOx are appropriate.

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[1] Information provided by Russell Nettles of the TCEQ Emissions Inventory group included 2002 Contaminant Summary Reports, and other detailed reports on each of the five facilities.

[2] Information provided by Russell Nettles of the TCEQ Emissions Inventory group included 2002 Contaminant Summary Reports, and other detailed reports on each of the five facilities.

CEMENT KILNS

Cement kiln emissions have been a source of considerable debate in the DFW area for several years. Also, there has been considerable debate on the control of emissions from cement plants in New York, Missouri, Iowa and Florida. As such, there is both historical information from previous hearings and regulatory processes, as well as newer information that is a result of recent technology applications in the U.S. and elsewhere. In future portions of this study we intend to gain the very best objective information on current methods for N0x reduction as it might be applied to the Ellis County facilities. While this is not a comprehensive engineering study, we do expect to provide a broad understanding that will significantly improve the basis upon which future air pollution related decisions may be made. Of course, in this report we relate the current conditions, upon which we will build our later reports.

Three cement plants operating in Ellis County are considered major sources of NOx. The three cement plants emitted nearly 10,968 tons of NOx from 10 kilns, based on the year 2002 Emissions Inventory. The specific emissions are as follows:

Ash Grove Cement Company – 2,572 tpy
TXI Operations – 4,221 tpy
Holcim Texas – 4,175 tpy

Based on information received from TCEQ, we can summarize the existing operations of the three plants.

Ash Grove Cement Company

The Ash Grove Cement Company operates three wet process kilns. The wet slurry and dry steel slag are fed into the feed end of each kiln. Upon passing through the final section of the pyro-process, exhaust gasses are controlled and collected. The exhaust gases are collected in electro static precipitators (ESPs) to remove particulate matter from the gas stream before it exits to the atmosphere. Fabric filters are used on other pieces of equipment including clinker coolers, various conveyors and hoppers. The exhaust gases do not have abatement devices for the control of NOx, however other NOx control techniques are employed. These techniques are discussed later in this section. Fuel for firing the kilns are limited to coal, coke, wood chips, and tire-derived fuel (TDF). Firing of TDF is limited to a maximum of 35 percent of total BTU requirements for Kiln Nos. 1, 2 and 3.[3] Table 2-2 summarizes these operations.

Table 2-2. Ash Grove Cement Company.

UNIT	DESCRIPTION	2002 MATERIAL THROUGHPUT	2002 NOX EMISSIONS
		(TONS CLINKER)	(TONS PER YEAR)
KILN 1	WET PROCESS	303,085	823.9
KILN 2	WET PROCESS	306,799	829.2
KILN 3	WET PROCESS	309,192	918.6
	TOTAL	**919,076**	**2571.7**

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[3] North Texas Cement Company, Special Conditions, Permit No. 4791A.

TXI Operations, L.P.

TXI Operations operates four wet process kilns (kilns Nos. 1 through 4) and one dry process kiln (kiln No. 5). The older wet process kilns employ ESPs to remove particulate matter from the gas stream before it exits to the atmosphere. The dry process kiln includes fabric filter particulate removal, sulfur dioxide removal and afterburners. Kiln Nos. 1 through 4 are limited by regulation to firing the kilns with pipeline quality natural gas, fuel oil, coal or coke and waste-derived fuel[4]. Further, the clinker production rate for each of the kilns Nos. 1 through 4 shall not exceed 375,000 tons of clinker per year also by regulation. The average oxygen content measured at the kiln exit of Kilns Nos. 1 through 4 shall be maintained at/or above 0.75 percent by volume on a five-minute average.

Fuels fired in Kiln No. 5 are limited by regulation to pipeline quality natural gas and coal. The clinker production rate of Kiln No. 5 is limited to 2,200,000 tons of clinker per year. In addition, Kilns Nos. 2 and 3 are not authorized to operate when Kiln No. 5 is operating or in start-up mode. The exception to this condition is any two or the four wet kilns may operate in conjunction with Kiln No. 5, provided that the clinker cooler baghouse associated with any wet kiln that operates in conjunction with baghouse No. 5 has been upgraded with high efficiency baghouses. This upgrade has occurred for both Kiln Nos. 2 and 3. Since Kiln Nos. 2 or 3 clinker cooler baghouses have been upgraded, at least three of the four clinker cooler baghouses can be operated with high efficiency bags at any time that all four wet kilns are in operation.
Table 2-3 summarizes TXI Operations.

Table 2-3. TXI Operations, L.P.

UNIT	DESCRIPTION	2002 MATERIAL THROUGHPUT	2002 NOX EMISSIONS
		(TONS CLINKER)	(TONS PER YEAR)
KILN 1	WET PROCESS	(375000)[1]	1010.2
KILN 2	WET PROCESS	(375000)[1]	24.3
KILN 3	WET PROCESS	(375000)[1]	375.6
KILN 4	WET PROCESS	(375000)[1]	988.4
KILN 5	DRY PROCESS	(2,200,000)[1]	1822.7
	TOTAL	**1,780,729**	**4221.2**

[1] Maximum allowable clinker production rates represented in parenthesis.

Holcim Texas, L.P.

Holcim operates two dry process kilns. The two kilns employ fabric filters for particulate control. Fuels fired in the kiln and precalciners are limited to pipeline quality natural gas, coal, tire-chip fuel (TCF) and wood chips, oil filter fluff, and on-site generated used oil, greases, used sorbents, and rags.[5] The TCF fuel is limited to 45 percent on an hourly average basis of the total fuel fed in the kiln systems on a higher heating value (HHV) basis. In addition, fuel cannot be injected into the precalciner unless the precalciner temperature is greater than 1200 °F.
Table 2-4 summarizes the Holcim Texas operations.

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[4] TXI Operations, Special Conditions, Permit No. 1360A.

[5] Holcim Texas, L.P. Special Conditions, Permit No. 8996/PSD-TX-454M2.

Table 2-4. HOLCIM Texas, L.P.

Unit	Description	2002 Material Throughput	2002 NOx Emissions
		(Tons Clinker)	(Tons per Year)
Kiln 1	Dry Process	1,168,844	1909.7
Kiln 2	Dry Process	1,073,650	2265.1
•	**TOTAL**	**2,242,494**	**4174.8**

Current Regulations

On April 19, 2000 the TCEQ adopted rules requiring Portland cement kilns in Bexar, Comal, Ellis, Hays, and McLennan Counties to meet specific NOx emission limits. Under the adopted rules, owners and operators of cement kilns were given several options to meet the emission requirements in Chapter 117. Specifically, owners and operators of cement kilns were given options for complying with emission limits in pounds of NOx per ton of clinker produced. The emissions specification contained in Chapter 117.265 are as follows:

1) for each long wet kiln:
    a. in Bexar, Comal, Hays, and McLennan Counties, 6.0 pounds per ton (lbs/ton) of clinker produced and
    b. in Ellis county, 4.0 lbs/ton of clinker produced
2) for each long dry kiln, 5.1 lbs/ton of clinker produced
3) for each preheater kiln, 3.8 lbs/ton of clinker produced; and
4) for each preheater-precalciner or precalciner kiln, 2.8 lbs/ton of clinker produced.

The adopted rules allow owners and operators of cement kilns several options to meet the above limits. Operators may choose to comply with the above limits on the basis of a weighted average for the cement kilns where there are multiple kilns in the same account. Further, for each wet or long dry kiln, owners and operators are not required to meet the NOx emission limits if the following controls are installed and operated during kiln operation:

(1) a low-NOx burner and either:
    (a) mid-kiln firing; or
    (b) some other form of secondary combustion achieving equivalent levels of NOx reductions; or alternatively
(2) other additions or changes to the kiln system achieving at least a 30% reduction in NOx emissions

Lastly, each preheater or precalciner kiln for which either a low-NOx burner or low-NOx precalciner is installed and operated during kiln operation is not required to meet the emission limits, and an owner or operator may also use Emission Credits for compliance to meet the NOx emission reductions.

The compliance schedule for meeting these requirements was May 1, 2003 for cement kilns placed into service before December 31, 1999 (Chapter 117, Subchapter E: Administrative Provisions, 117.524). For cement kilns in Ellis County for which an owner or operator has filed an application for modification to meet the requirements of Regulation 117 on or before May 30, 2003, the compliance date was extended until 6 months after issuance of the permit for operation of a low-NOx burner and 12 months after issuance of the permit for operation of a secondary combustion system. We have not reviewed the applications that have been filed for these plants, however we understand that the permit applications do not contain any plans for installing additional control equipment[6]. Rather, the applications are for optimizing the existing NOx control techniques that already exist (see discussion below).

Exiting Control Technology

Kilns in Ellis County have employed or propose to install a variety of controls to reduce NOx emissions. These controls include process modifications, staged combustion, mid-kiln firing and the installation of low-NOx burners. Additional, possible future controls, will be addressed in a future report.

Process Modifications

Process modifications, which reduce NOx emission without the installation of specific control equipment, include the ChemStar process (EC/R, 2000). This process requires the addition of a small amount of steel slag to the raw kiln feed. Steel slag has a low melting temperature and is chemically very similar to clinker. Since many of the chemical reactions required to convert steel slag to clinker have already taken place in the steel furnace, the fuel needed to convert steel slag into clinker is low. The decreased need for limestone calcinations per unit of product and improved thermal efficiency of the process both contribute to reduced thermal NOx. The ChemStar process is employed by the Ash Grove Cement and TXI Operations on its wet process kilns. This process can reduce NOx emissions by 30 percent and increase production by 15 percent.

Changing the kiln fuel also has an impact on NOx emissions. For example, changing the kiln fuel from natural gas to coal can reduce flame temperatures significantly, resulting in lower NOx emissions. Switching to a fuel with a higher heating value (HHV) and lower nitrogen content may also reduce NOx emission from a cement kiln. Petroleum coke has a lower nitrogen content per million btu than coal and is more uniform in terms of heat value, lower in volatile matter content and burns with a lower flame temperature. Coke and coal are both fuels that are allowed in the operating permits of the Ellis County cement kilns.

Staged Combustion and Low-N0x Burners

Staged combustion is another technique currently used in some Ellis County kilns including preheating and calcination of the raw materials at much lower temperatures than the primary zone kiln burning zones. In the secondary combustion zones, part of the fuel is burned at a much lower temperature. In a typical precalciner kiln, almost 40 to 50 percent of the fuel is burned at a lower temperature, which reduces the thermal NOx formation.

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[6] Personal Communication with Skip Clark, of the TCEQ's Permits Division on February 12, 2004.

Tire-derived fuel can also be added to the feed end of a preheater or precalciner kiln. Tire-derived fuel (TDF) is employed in Kiln No. 1 at the Holcim facility. Likewise, waste-derived fuel is used for firing at all 4 wet process kilns at TXI Operations.

Anther staged combustion technique is referred to as Mid-Kiln Firing (MKF). In this process, solid fuel is fed into the calcining zone of a rotating long kiln using a specially designed feed injection system. MKF allows part of the fuel to be burned at a material calcinating temperature that is much lower than the clinker burning temperature. To maintain continuity in the heat input, solid and slow burning fuels (such as tires) are most amenable for MKF. This technique is employed at Kiln Nos. 1, 2, and 3 at the Ash Grove Cement Company. In addition, this technology was studied at the TXI facility for all four wet kilns from July to November of 2002.The most significant costs associated with this process are those for kiln modifications necessary to facilitate the secondary fuel, and the solid fuel conveying system.

Some cement kiln burners use low-NOx burners. These burners are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel–rich zones for initial combustion. The longer, less intense flames resulting from the staged combustion lower flame temperatures and reduce NOx formation. Low-NOx burner technology is used on the dry kiln at TXI Operations.

UTILITY ELECTRIC GENERATION

Two energy plants operating in Ellis County are considered major sources of NOx. The two power plant plants emitted nearly 811 tons of NOx, based on the year 2002 Emissions Inventory. The specific emissions are as follows:

Midlothian Energy – 721.1 tpy
Ennis Tractebel – 89.3

Based on information received from TCEQ, we can summarize the existing operations of the two plants.

Midlothian Energy

Midlothian Energy owns and operates four combined cycle turbine generators rated at a combined nominal capability of 270 MW each. The combustion turbines are ABB Model GT24 with steam injection in combined cycle with Heat Recovery Steam Generators and Steam Turbines. Each are rated at 175 MW electric. Two additional combined cycle generating units are located at the Midlothian facility. The two additional turbines include two ABB Model GT24 gas turbines without steam injection in combined cycle with heat recovery steam generators. Each unit has a single electric generator rated at a nominal capacity of 250 MW each[7]. Fuel for the first combustion turbines are limited to pipeline quality natural gas and No. 2 fuel oil containing no more than 0.05 percent total sulfur, by weight[8]. The use of No. 2 fuel oil is limited to 720 hours per year for each of the first four gas turbine generators. In addition to the 6 generating units, there are 4 natural gas fired heaters at the Midlothian Plant.

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[7] Midlothian Energy L.P., Permit Amendment, Source Analysis & Technical Review, Record No. 66908 & 66909.

[8] Midlothian Energy L.P., Special Conditions, Permit Nos. 38191 and PSD-TX-906.

Table 2-5 presents a summary of the Midlothian Energy Facility.

Table 2-5. Midlothian Energy L.P.

UNIT	DESCRIPTION	MW RATING	EMISSION LIMIT	2002 NOX EMISSIONS
			(ppmvd)	(TONS/YEAR)
Unit 1	HEATER (12 MMBTU/HR)	N/A	See footnote 9	4.48
Unit 2	HEATER 12 MMBTU/HR)	N/A	"	4.80
Unit 3	HEATER (3.5 MMBTU/HR)	N/A	"	0.70
Unit 4	HEATER (3.5 MMBTU/HR)	N/A	"	0.75
Unit 1	COMBINED CYCLE GAS TURBINE	175	5	140.20
Unit 2	COMBINED CYCLE GAS TURBINE	175	5	124.20
Unit 3	COMBINED CYCLE GAS TURBINE	175	5	95.30
Unit 4	COMBINED CYCLE GAS TURBINE	175	5	106.60
Unit 5	COMBINED CYCLE GAS TURBINE	180	5	115.70
Unit 6	COMBINED CYCLE GAS TURBINE	180	5	128.40
	Total			**721.13**

The total fuel use for each of these operations was not available from the TCEQ at the time of this report. This information will be needed for future cost assessments if additional controls are technically feasible.

Ennis-Tractebel

The Ennis Tractebel generating facility consists of one 230 MW Westinghouse Model 501G combustion turbine, equipped with a non-fired heat recovery steam generator (HRSG). Total electric power output from the facility will be 350 MW. The turbine is fired with pipeline quality natural gas only[10].

Following is a summary of the facility.

UNIT	DESCRIPTION	MW RATING	EMISSION LIMIT	2002 NOX EMISSIONS
			(ppmvd)	(TONS/YEAR)
Unit No. 1	COMBUSTION GAS TURBINE	230	9	89.52
	Total			**89.52**

The total fuel use for this facility in 2002 was 7,912,613 cubic feet.

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[9] Heater flue gasses are treated conjointly with the turbine exit gases, and thus emissions limits for Units 1-4 of both the heater and the turbine have a combined limit as shown.

[10] Ennis-Tractebel Power Company, Inc., Preliminary Determination Summary, Permit No. 340363 and PSD-TX-927.

Current Regulations

Current regulations for Combustion at Major Sources for Electric Generation do not apply to Ellis County. Chapter 117-Control of Air Pollution from Nitrogen Compounds, Subchapter B, Combustion at Major Sources, Division I, Utility Electric Generation in Ozone Nonattainment areas apply to the Dallas/Fort Worth ozone nonattainment area. Ellis County in not included in this designation. However, as discussed below, the two energy generation facilities have installed emission control equipment which was required during the permitting process.

Exiting Control Technology

NOx control methods for gas turbines include methods that reduce NOx that is generated in the combustion process itself (primary controls) and methods that reduce NOx after it is generated in the combustion process in the exhaust gas (secondary controls).

Dry Low NOx Combustors (DLNC) is one of the most widely used primary methods to control NOx in turbine combustors. Some suppliers offer combustors on new turbines that are capable of NOx emissions under 9 ppmdv (parts per million dry volume basis) at 15 % oxygen when firing on natural gas. DLNC technology utilizes a lean, premixed flame as opposed to a turbulent diffusion flame, therefore typically requiring the use of natural gas. In a lean, premixed combustor, the fuel and air are premixed prior to entering the combustion zone. With a lean, premixed flame, the contribution of prompt and thermal NOx can be much lower than for a turbulent diffusion flame. The use of low-nitrogen fuels such as natural gas minimizes the contribution of fuel NOx.

Selective Catalytic Reduction (SCR) is the exhaust treatment (secondary) technology that is most widely used on gas turbines. It is required on most new gas turbine installations particularly those with Heat Recovery Steam Generators (HRSG). Gas turbines equipped with SCR have been guaranteed to 2 ppm NOx.

Simple cycle gas turbines are most commonly controlled with water injection, dry low NOx combustors, or selective catalytic reduction. Water injection has a higher energy cost than DLNC or SCR. However, the initial cost of water injection is lower than other controls. Combined Cycle Gas Turbines are typically controlled with SCR.

Those turbines with DLNC can achieve an additional 20% control by the additional application of SCR. SCR control techniques have been widely used in simple cycle gas turbines and almost exclusively in combined cycle gas turbines.

The Midlothian Energy gas turbines met the BACT requirements of the TCEQ by applying SCR in combination with DLNC for the two newest turbines (Unit Nos. 5 and 6. These units were permitted at 5 ppmvd. The first four units (Unit Nos. 1 through 4) employ SCR and are limited to 5 ppmvd when corrected to 15 % oxygen when fired on natural gas and 9 ppmvd corrected to 15 % oxygen when firing on fuel oil[11].

The Ennis Tractebel gas turbines use SCR with NOx emissions levels limited to 9.0 ppmvd.[12]

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[11] Midlothian Energy L.P., Special Conditions, Permit Nos. 38191 and PSD-TX-906.

[12] Ennis-Tractebel Power Company, Inc., Special Conditions, Permit Nos. 40363 and PSD-TX-927.

3. EVALUATION OF NOx EMISSIONS REDUCTIONS

INTRODUCTION AND PURPOSE

The previous section evaluated the current NOx emission control techniques in place at major sources in Ellis County. The next step is to evaluate the potential for additional NO_x reductions (that is, beyond current regulatory requirements) from Point Sources in Ellis County. Earlier work established that five sources, three cement plants and two power plants, account for 96% of point source NOx emissions in Ellis County. Annual 2002 emissions from these five plants, based on TCEQ data[1], are as follows:

Facility	2002 NO_x (tons/yr)
Ash Grove Cement	2,572
TXI Operations	4,221
Holcim Texas	4,175
Midlothian Energy	721
Ennis Tractebel Power	89

The cement plants collectively produced more than 90%, of 2002 NOx emissions from these five plants. In addition, the two power plants have SCR on all turbines and have limited potential for further reductions. Thus, given the limited resources available to this project, and the importance of this source category in term of total NOx emissions and emissions reduction potential in the County, this analysis focuses exclusively on the cement plants.

This section discusses cement plant operations and equipment, available NOx control methods and technology, the equipment and controls current in place at Ellis County cement plants, and the technical feasibility of applying additional NOx controls. Our analysis and conclusions must be considered preliminary, since they are based on general information about the facilities in Ellis County and do not involve a detailed engineering analysis of plant equipment or operations. Detailed assessment of the actual emissions reductions likely from these facilities would require substantial equipment vendor interaction and plant engineering design. While we have done a preliminary engineering "scoping" assessment, including some very limited vendor discussions, this cannot replace the much more complex and costly process of actual engineering design. Thus the purpose of this study is to guide the reader in making a "first cut" assessment of the potential for emissions reductions through the use of the technologies discussed herein, and provide some insight on next steps that may be considered. Table 3-1 identifies the available control methods and potential emissions reductions that are evaluated in this section.

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[1] See Preliminary Task 1 and Task 2 reports for additional background on emissions estimates.

Table 3-1. Available control technologies for cement plants.

NOx Control Technology	Applicable Kiln Type		NOx Emission Reduction (%)[1]
	Wet	Precalciner	
Process Controls	X	X	<25
ChemStar	X	X	-23-40
Low-NOx Burner	X	X	4-47
Mid-kiln Firing (Wet Kilns)	X		28-59
Mid-kiln Firing (Dry Kilns)		X	11-55
Tire Derived Fuel[2]	X	X	30-40
SNCR		X	10-50
SCR		X	80-95
BioSolids[3]		X	15-30
Oxidation	X	X	80-95
Combination (MSC/SNCR)		X	38-68

[1] Emissions reductions represent tests obtained from review of the literature

[2] Based on TDF in a precalciner with BSI technology

[3] Personal communication from Dr. Anne McQueen, ENVIRON International Corporation, March 2004.

The analysis of cost of installing and operating the equipment described here is addressed in a subsequent section. That subsequent section also provides some comparative "cost effectiveness" figures for other emissions reductions that have been or are being considered for other types of emissions sources, such as trucks, cars, and area/stationary sources.

In conducting this analysis we drew information from a wide variety of sources. In our evaluation we have focused on several technologies that are available to control NOx from cement kilns. These include the application of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) technologies. In addition, have looked at oxidation technology, which has been successfully demonstrated on other sources of pollution but to date, but not on cement plants. To conduct our evaluation, we reviewed available documents from other states and control agencies with air quality problems as well as work that has been conducted in Europe on similar facilities. Among the numerous sources of information for conducting this evaluation, we have also looked at a pending permit application for St. Lawrence Cement in New York, the permit issued by the Iowa Department of Natural Resources for the Lehigh Cement Company plant in Mason City, Iowa, the permit application to the Missouri Department of Natural Resources for a Holcim Cement plant near St. Louis, tests conducted on cement plants in Germany and Sweden, the use of the oxidation system developed by BOC Process Gas Solutions at a reverbertory furnace used for lead smelting in the City of Industry, California, and an analysis of the costs for installing SNCR by Holcim Texas, L.P.. We have also reviewed articles published by the Air & Waste Management Association and other sources, including articles and papers describing installations of NO_x control technologies in Europe, where some of the more advanced control technologies have been applied.

CEMENT PLANT PROCESSES AND EQUIPMENT

Overview

The process of Portland Cement manufacturing consists of quarrying and crushing the raw materials, grinding the carefully proportioned materials to a high degree of fineness and pyroprocessing the raw mix in a rotary kiln. The rotary kiln is a refractory brick-lined cylindrical steel shell [3 to 8 m (10 to 25 ft) wide, 50 to 230 m (150 to 750 ft) long] equipped with an electrical drive to rotate the kiln on its longitudinal axis at 1 to 3 rpm. It is a countercurrent heating device slightly inclined to the horizontal so that material fed into the upper end travels slowly by gravity to be discharged into the clinker cooler at the lower, discharge end. The burners at the firing end, i.e., the lower or discharge end, produce a current of hot gases that heats the clinker, and the calcined and raw materials in succession as it passes upward toward the feed end.

The basic raw materials are oxides of calcium, silicon, aluminum, and iron. The silica and alumina are derived from a clay, shale, or overburden from a limestone quarry. Some plants supplement the iron with mill scale, pyrite cinders or iron ore. Feed material gradually tumbles to the high-temperature end of the kiln, which is sometimes referred to as the "burn zone". The key material produced by the process, which is called "clinker", is produced by heating limestone to temperatures over 2,650 °F, - a process that requires combustion temperatures of about 3,000 °F. The tiled kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln. After exiting the kiln, the clinker is ground to a fine powder along with appropriate amounts of gypsum to produce cement.

Industrial by-products are becoming more widely used as raw materials for cement, including slags and fly ash from boilers. Coal is often the fuel of choice in cement kilns, primarily because of it low cost, but also because the ash contributes to the product. Additional fuels include natural gas, coke, fuel oil, tire chips (sometimes called "tire derived fuel" or "TDF"), wood chips, and waste derived fuel such as sewage sludge. Because of the high temperatures and long residence times inherent in combustion in kilns, cement plants are sometimes used to treat hazardous wastes.

Processes and Equipment

Cement kilns fall into four general process categories: wet kilns, long dry kilns, preheater kilns and precalciner kilns. Wet process kilns are typically older and are often the choice where the moisture content of the raw materials mined from nearby quarries is high. Wet kilns are normally several hundred feet long, which is much longer than the kilns used in dry processes. In the wet process, the raw materials are ground with about 30 to 40 percent water to producing a well-homogenized mixture called slurry. The slurry is introduced into the feed end of the kiln and undergoes simultaneous heating and drying. As the kiln rotates, the refractory lining is alternately heated by the gases when exposed and cooled by the slurry when immersed. Thus the lining serves to transfer heat, as do the gases themselves. As most of the moisture is evaporated, nodules of material move down the kiln and are gradually heated to about 1650 °F (900 °C) where the calcinations reactions begin (EPA, 1994). As the charge leaves the burning zone and begins to cool, clinker minerals crystallize from the melt, and the liquid phase solidifies. The granular clinker material drops into the clinker cooler for further cooling.

The dry process utilizes a dry feed rather than a slurry. Other than the need for evaporation of water, its operation is similar to that of a wet kiln However, in one modification, the kiln has been lengthened to nearly the length of wet-process kilns and chains were added. The chains serve almost exclusively a heat exchange function. Refractory heat -recuperative devices, such as crosses, lifters, and trefoils, have also been installed to give the long dry kiln better energy efficiency than wet kilns. .

To further improve the energy efficiency of the dry process, variations such as suspension preheaters and precalciners have been introduced. In preheated kilns, dry pulverized feed passes through a series of cyclones where it is separated and preheated several times. The partially (40 to 50 percent) calcined feed exits the preheater tower into the kiln at about 1500 to 1650 °F (800 to 900 °C). In the precalciner kiln process, a second burner is utilized to carry out calcinations in a separate vessel attached to the preheater. This vessel, called a flash furnace, utilizes preheated combustion air drawn from the clinker cooler and kiln exit gases and burns about 60 per cent of the total kiln fuel. The raw material is calcined almost 95 percent, and the gases continue their upward movement through successive cyclone preheater stages in the same manner as the preheater kilns. The precalciner systems permit the use of smaller dimension kilns since only actual clinkering is carried out in the rotary kiln. The burning process and the clinker cooling operations are the same as the wet kilns.

The two types of processes used in Ellis County are the wet kiln process and the dry, precaliner kiln process.

NO_x Emissions

In cement manufacturing, conditions favorable for formation of thermal nitrogen oxides (NO_x) are reached routinely, primarily because of the high process temperatures involved. For example, the thermodynamic equilibrium NOx level at 3,000 °F (1600 °C) and 1 percent oxygen is about 1,500 ppm. Due to these high temperatures, fuel combustion in the kiln burning zone is the primary source of NOx formation in a cement kiln. The NOx formed is referred to as thermal NOx, which is basically the homogeneous reaction of oxygen and nitrogen in the gas phase at high temperatures. Due to the presence of nitrogen in the fuels, NOx is also formed by the conversion of the nitrogen in the fuels. Although the amount of NOx formed from fuel NOx is difficult to identify separately from the amount formed from thermal NOx, the thermal NOx is assumed to be the dominant mechanism is cement kilns. Therefore, most strategies are focused on reducing the formation of NOx by reducing combustion temperature, oxygen concentration in the high temperature combustion zone and the gas residence time at the high temperatures. Although heating occurs ahead of the kiln in dry preheating and precalcining processes, heating and drying equipment often utilize recycled kiln exhaust gas.

The NO_x produced by a plant varies by the characteristics of the raw feed, the type or mix of fuels, and the production process used. The physical characteristics and chemical composition of the raw feed affect NO_x emissions because of its nitrogen content and the energy required to process it. The nitrogen content of fuels varies significantly. Both oil and natural gas have relatively low fuel bound nitrogen content, whereas coal may contain 1 to 3 percent of nitrogen by weight depending upon the source of coal. Waste-derived fuels (WDF) such as scrap tires, petroleum wastes and, solvents may contain significant quantities of nitrogen. Among process designs, wet kilns tend to have the highest heat input per ton of clinker (typically around 6 MMBtu/ton) (NESCAUM, 2000) and therefore greater NOx emissions per unit of production. Preheater and precalciner kilns use less heat and can run less than 4 MMBtu/ton. Emission factors published by EPA for wet process kilns are 7.4 lb/ton of clinker, 4.8 lb/ton of clinker for kilns with preheaters and 4.2 lb/ton of clinker for kilns with precalciners (EPA, 1995).

The many variables that affect NOx formation introduce significant uncertainty into any analysis of NOx control effectiveness and cost-effectiveness. This variability must ultimately be considered on a plant-by-plant basis to determine the efficacy and cost-effectiveness of potential future regulatory requirements.

AVAILABLE NO_X CONTROL METHODS

For an existing facility, available strategies for reducing NOx include modernization, altering feed composition, combustion improvements, and post combustion controls. Modern dry kiln processes, with preheating and precalcining, are more energy efficient and produce less NOx per unit of production, but are not considered a control method for purposes of this discussion. The practicality and effectiveness of each control method depends on existing conditions.

Retrofit applications are generally more challenging than new installations and often cost more. Among the factors that must be considered are, space available, existing equipment configurations, fuels used, existing emission control systems, and operator capabilities and training. If off-the-shelf system designs and equipment cannot be used, custom design, engineering and construction practices can add significant cost to the obvious technical challenges involved. While this evaluation provides an analysis of the availability of various methods to reduce NO_x emissions, it does not address specific retrofit considerations for Ellis County facilities. However, issues that would require additional considerations are identified with recommendations where such issues should be further investigated.

Changing Feed Composition

One commercially available approach to reducing NOx emissions by altering feed composition is called the ChemStar process. It was discussed in the previous section and is also described as follows in a recent EPA report.

> "Another feed modification that can reduce NOX emissions is the addition of a small amount of steel slag to the raw kiln feed. This patented technique is known as the ChemStar Process and was developed by TXI Industries. Steel slag has a low melting temperature and is chemically very similar to clinker. Since many of the chemical reactions required to convert steel slag to clinker have already taken place in a steel furnace, the fuel needed to convert steel slag into clinker is low. The decreased need for limestone calcination per unit product and improved thermal efficiency of the process both contribute to reduced thermal NOX and CO2 emissions. ChemStar requires little extra equipment and the addition of steel slag to the feed mix can result in a reduction or elimination of the need for some mineral sources, such as shale or clay. This process can

also increase production by 15 percent. The amount of NO_X emissions reductions achievable with ChemStar varies by kiln type but ranges from over 20 to 60 percent." (EC/R, 2000).

Fuel Composition

In the previous section it was noted that different fuels have different heating values and fuel bound nitrogen content and therefore have varying rates of NOx formation. Coke produces less NOx than coal, and coal less than natural gas, though there are obviously additional environmental impacts from the use of coal (EC/R, 2000). Tire-derived fuel (TDF) can also be added to the feed end of a preheater or precalciner kiln. One report noted that the addition of waste tires reduces NOx emissions from the kiln by 30 to 40 percent, and there is no significant change in toxic, hydrocarbon, or metal emissions (EC/R, 2000). Since the cost and availability of fuels varies significantly at the local level, this method of reduction is appropriately considered on a plant-by-plant basis.

Improving Combustion Efficiency

Monitoring and effectively limiting excess air can improve combustion and reduce thermal NOx formation in the kiln. According to an EPA report, NOx formation can be reduced by 15% (EC/R, 2000). As discussed in Task 2, related methods are staged combustion and the use of more sophisticated burners. By design, modern dry kiln processes heat raw feed and begin calcinations at lower temperatures than in the primary combustion zone of the kiln. This results in lower thermal NO_x formation than wet kilns. Another staged combustion technique is the addition of mid-kiln firing (MKF) with solid fuels, such as tire chips. Again, the result is that part of the combustion process occurs at lower temperatures, thereby leading to reduced formation of thermal NOx. MKF is reported to reduce NOx by an average of 33% for dry kilns and 40% for wet kilns (EC/R, 2000).

While mid-kiln firing was discussed in the previous section, it is important to note that this technique has been used successfully at several cement kilns including the Ash Grove wet process kilns. It should be further noted that mid-kiln firing was demonstrated to be successful on the wet process kilns (kilns 1-4) at TXI from July to November 2002.[2] Based on information provided by TXI, CEMS data showed that a reduction of 37 percent in NOx was achieved when firing 2 tires per minute and a 64 percent reduction when firing 4 tires per minute. However, because the wet kilns also fire liquid hazardous wastes, a RCRA permit authorization would be required to modify the plant to use mid-kiln firing on a permanent basis. This appears to be an issue of the date for compliance rather than a technical issue with the feasibility of the technology. According to information from Cadence, the developer of the feed fork technology using whole tires that are dropped into the kiln at each revolution. This technology has demonstrated the potential for reducing NOx emissions by 38 percent on one kiln with an average of 33 percent reduction on nine dry kilns.

Low NO_x burners can be installed on any type of kiln. These burners reduce flame turbulence, lower flame temperatures and result in less NO_x formation. An important consideration on

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[2] Standard Permit, Technical Review, No. 53424, TXI Operations, December 31, 2002.

reducing NO_x emissions using low-NO_x burners is the firing system. A majority of the kilns in the US are direct fired. That is, the systems introduce a large proportion of combustion air with the fuel being burned. Indirect firing systems on the other hand use only a small portion of combustion air to convey fuel and thus use less primary air. In general, indirect firing systems produce less NO_x emissions. Furthermore, some cement kiln burners specifically identified as Low-NOx burners typically use 5 to 7 percent primary air and thus can be used only on indirect fired systems. Therefore, converting to indirect firing will allow the use of low-NOx burners and thereby reduce emissions. Reductions per ton of clinker of 15% to more than 40% have been reported, depending on the burner used and type of kiln (EC/R, 2000).

Selective Non-Catalytic Reduction (SNCR)

The control technology relies on the reduction of NOx in exhaust gases by injecting ammonia or urea without the use of a catalyst (EPA, 1994). This approach avoids problems related to catalyst fouling, but requires injection of reagents in the kiln at a temperature "window" of 1600 to 2000 °F (870 to 1090 °C). At these temperatures, the urea decomposes to produce ammonia, which is responsible for NOx reductions. To achieve full effectiveness, SNCR systems must operate in a section of the kiln with the proper temperature and residence time. At lower temperatures, the NOx reduction reactions become too slow resulting in too much un-reacted ammonia, which is usually referred to as ammonia slip when discharged to the atmosphere. The effective temperature window range can be lowered to about 1300 °F (700 °C) by the addition of hydrogen along with the reducing agent. Several other reagents can also shift the temperature window.

SNCR has demonstrated significant reductions of NO_x when applied on dry precalciner kiln configurations. In preheater/precalciner kilns, the temperatures at the cooler end of the rotating kiln, in the riser duct, and in the lower section of the cyclone preheater tower are likely to be in the correct temperature range for this technology. In a demonstration of urea SNCR at the Ash Grove Cement plant in Seattle Washington, over 80 percent NO_x reduction was achieved. This was a demonstration project on a preheater/precalciner kiln unit (NESCAUM, 2000). Ammonia slip was reported at less than 10 ppm.

Most of the experience with SNCR has been in Europe where the technology has been applied on 18 cement kilns (EC/R, 2000). SNCR was installed in two Swedish dry process cyclone preheater/precalciner kilns in 1996/97. A reduction of 80 to 85 percent was achieved at both kilns (IPPCB, 2000). One of the kilns was 20 years old with a capacity of 5,800 tons of clinker per day and initial levels of NOx about 1100 mg/Nm^3. Small amounts of ammonia slip were estimated, but not specified. In addition, there was reported that there was no increase in CO emissions. Another plant in Sweden (Slite Cement Plant) operates two kilns with SNCR, the largest of which is a 20 year old 5-stage double preheater and precalciner with a capacity of 5,800 tons of clinker per day and a second kiln with a capacity of 1,200 tons per day. It has been shown at this plant that with careful operation of the kilns, the SNCR can obtain a reduction in NOx of 85 percent. An additional application of SNCR was tested in two German plants Geseke and Burglengenfeld. The plants, operated by Dyckerhoff Zement GmbH and Heidelberger Zement AG, were tested in 1995/96 (Haug, 2002). These plants were able to achieve levels below the limit of 800 mg/m^3 (Germany emission limits) from uncontrolled levels between 1200 and 1500 mg/m^3 (>33 to 47 percent reduction). However, in the Geseke plant, higher emissions of ammonia were detected. It was therefore concluded by the author of the paper describing this application that SNCR has limited use in the cement industry due to the need to optimize temperatures and duration periods. Most SNCR installations in Europe today are designed and operated for NOx reduction rates of 10 to 50 percent taking into consideration the ammonia slip (SEPA, 2000).

In addition to the European experience, NOx reduction levels ranging from 25 to 50 percent were achieved at three precalciner units at Taiwan Cement. Ammonia slip was reported at 15 ppm at this facility.

The technology is beginning to gain a foothold in the U.S. market. Iowa recently agreed to SNCR on the Lehigh Portland Cement in Mason City. The PSD permit issued will require the use of SNCR for this plant. This was part of a settlement agreed with the State of Iowa.[3]. In addition, the Missouri Department of Natural Resources has placed a draft air pollution permit for the proposed Holcim cement plant on public notice (MDNR, 2004). Based on the draft permit the facility, which is proposed for a location south of St. Louis in Ste. Genevieve County, will likely require the use of SNCR to meet emission limits. In its analysis, the Missouri DNR concluded that SCR was not feasible at this time but concluded that good combustion practices, Low-NOx burners, multi-stage combustion, and SNCR are technologies that should be considered for this facility. Finally, SNCR is being proposed at the St. Lawrence Cement Company manufacturing facility in Hudson/Greenport New York.[4] We understand that the state of New York has now issued a request for additional information that includes information on the use of SCR for this facility.[5]

The technology has a major limitation in that it is very difficult to apply in long dry or wet kilns. Although mid-kiln firing of containerized solid fuels allows injection of a certain amount of reagent into the appropriate temperature zone, this technique can result in the rapid decomposition of solid ammonium or urea salts. A means of continuously injecting ammonia or urea-based reagents into the appropriate temperature zone has not been developed due to the rotating of the kilns.

In designing and operating SNCR systems, it is important to maintain the proper temperatures for the reaction with ammonia to occur. If the temperatures fall below the appropriate temperature window unconverted ammonia is emitted (referred to as ammonia-slip). A temperature above the window, ammonia slip may also occur. The formation of aerosols of ammonia chlorides and ammonia sulfates that pass through the filter can become visible as a white plume above the exhaust stack.

Biosolids Injection (BSI)

This technology was developed by the cement industry for NOx reduction in precalciner and preheater kilns. With this technology, dewatered sewage sludge is added to the mixing chamber of the calciner. The dewatered biosolids provide a source of ammonia, producing an SNCR-like reaction to reduce NOx. At a Mitsubishi Cement Kiln in Lucerne Valley, California, BSI

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[3] Personal Conversation with Chris Rowling, Iowa Department of Natural Resources on March 11, 2004.

[4] St. Lawrence Cement Co., LLC (SLC) applied to the New York State Department of Environmental Conservation (Department or DEC) for permits to construct and operate a cement manufacturing facility in the Town of Greenport and City of Hudson, April 2001.

[5] ALJ Recommended Decision for the St. Lawrence Cement Company, State of New York DEC, February 23, 2004.

provided about a 50 percent reduction in NOx concentrations, from 250 ppm (at 12 % Oxygen) to 120-125 ppm (at 12 % Oxygen). An additional benefit for this technology is the potential revenue stream it can create for the cement plant. Many communities are willing to pay a tipping fee for accepting biosolids.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is the process of using ammonia in the presence of a catalyst to selectively reduce NOx emissions from exhausts gases. The SCR process has been used extensively for gas turbines, internal combustion engines and fossil fuel-fired utility boilers. In this system, anhydrous ammonia, usually diluted with air or steam, is injected through a catalyst bed to carry out NOx reduction reactions. A number of catalyst materials have been used, such as titanium dioxide, vanadium pentoxide and zeolite-based materials. The catalyst is typically supported on ceramic materials, e.g., alumina in a honeycomb monolith form. The optimum temperature for the catalyst reactions depends upon the specific catalysts used, but occur in the range from 570 to 840 °F (300 to 450 °C). This can be higher than typical cement kiln flue gas temperatures especially in plants that use heat recovery systems, or use a bag house for particulate collection. Because catalysts can be fouled by particulates, the presence of alkalis, line and sulfur dioxide in the exhaust gases are of concern.

In an SCR system, ammonia is typically injected to achieve a NOx conversion of 80 to 90 percent with an ammonia "slip" of about 10 ppm of the unreacted gases leaving the reactor (EC/R, 2002). The NOx removal efficiency depends upon the temperature, the molar ration of the ammonia to NOx and the flue gas residence time in the catalyst bed. All of these factors must be considered in designing the desired NOx reduction, the appropriate reagent rations, the catalyst bed volume and the operating conditions. Furthermore, ammonia storage and handling, community impact of ammonia emissions are all considerations that must be taken into account to assure safe operations. As with SNCR, the appropriate temperature window must be maintained to assure that ammonia slip does not result in a visible plume.

The installation of an SCR system in a cement plant can occur at two different locations: 1) after the dusting process (particulate collection device) and before the furnace as a "low-dust" set up, or 2) after the last cyclone without dusting as a so-called "high-dust" set-up.

The advantage of a "low-dust" set-up are longer the catalytic converter operation times and lower danger of blockage. The disadvantage is additional energy costs because the cooled exhaust needs to be heated to achieve proper reaction temperatures for the catalyst. This pattern was shown in three early pilot tests conducted by Hitachi Zosen to evaluate SCR on cement kilns in 1976 (EPA, 1994). During these tests, two suspension preheater kilns and a wet process kiln were tested for 5,400 hours each. Electrostatic precipitators were used to remove particulates before the flue gas entered the SCR unit. Also a heat recovery system equipped with supplemental fuel firing was provided to raise the flue gas temperatures to the required reaction temperatures. Initial NO_x removal efficiencies of 98 percent were achieved in slipstreams of about 3,000 scfm. However, after 5,400 hours of operation, NO_x removal efficiencies dropped to about 75 percent due to catalyst coating.

The advantage of the high dust set-up is that the temperature of the exhaust after the cyclone stage is more or less equal to the temperature required for the catalyst. Additional heating is not necessary. However, a "high-dust" SCR installation, which is used for most boilers equipped with SCR, has not been recommended because the high calcium content of the dust in cement kilns form deposits on the catalysts and reduce efficiency below acceptable levels.

A recent application of SCR at the Solnhofen Portland Zementwerke AG (SPZ) has shown that a "high-dust" SCR application can be achieved with proper management. This plant, which has been in full-scale operation for over two years, has shown significant NOx emission reductions as well as hydrocarbon, ammonia, and sulfur dioxide emissions.[6] This facility produces clinker in a rotary furnace with cyclone preheaters and post clinker chillers. This plant has burn zone temperatures above 1,400 °C (2,500 °F) with temperatures reaching 2,000 °C (3,600 °F) during the gas phase. Due to the high temperatures and the long duration, the process produces significant NOx emissions. Prior to designing the SCR system for the main plant, a pilot plant was constructed so that the last cyclone stage was parallel to the exhaust channel. A partial stream of the exhaust from the main operation was directed over the reactor. The reactor was designed with four different catalytic converter types to test different configurations and space velocities. Cleaning intervals for the catalysts were defined that would be realistic for large-scale plants. For successful operation, the cleaning intervals were designed close to the pressure drop of a maximum of 4 to 5 mbar. Results have shown that NOx reductions from 1,200 mg/m^3 to 200 mg/m^3 using the SCR process (>80 percent). The reductions occurred in the range of 250 to 450 °C. To date, this plant has been in operation for 24,000 hours and demonstrates greater than 80 percent NOx reductions.[7] According to Mr. Lugar of KWH Catalysts, Inc., the problem of fouling from the heavy dust loading has proven to be quite manageable with regular cleaning of the catalyst.

According to a recent report, while SCR has only been tested on preheater and semi-dry kiln systems, it might be applicable to other kiln systems as well (IPPCB, 2000).

Oxidation Technology

This technology is a post-combustion control system that uses wet or semi-dry scrubbers to remove NOx by the addition of ozone as a treatment chemical to increase the solubility of relatively insoluble gaseous NOx. This technology has been developed by BOC Gases and is referred to as the LoTOx System. This system, which has been commercialized for about four years, has already been installed and operated in a variety of industries including steel, power production and recycling. According to BOC Gases, the LoTOx system has a small and adaptable footprint and can be applied in retrofit designs. The system has been used in a gas-fired boiler application to achieve levels below 0.15 lb/MMBtu of NOx and even as low as 5 ppm NOx. (85 to 90 percent control) Applications of this technology also include a natural acid pickling process in Pennsylvania, achieving 90 to 95 percent NOx removal, a 25 MW coal-fired boiler in Ohio achieving 85 to 90 percent NOx removal and a lead smelting furnace in California achieving 80 percent NOx removal. Although this technology has not been applied to a cement kiln operation, it may be a logical candidate for an existing NOx scrubber as those used on wet kilns.

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[6] Samant, Sauter and G. Fischer, Der Kat furs Zementwerk, Umwelt Magazine, December 2002.

[7] Personal Conversation with Tom Lugar of KWH Catalysts, Inc, on February 27, 2004.

Combination of Technologies

Combustion technologies can be combined with post-combustion technologies in some cases. It is also possible to combine multiple combustion technologies in cement kilns. For example, California Portland Cement in Colton California converted its two long dry kilns to indirect firing to permit the use of a low-NOx burner in the kiln.

In Germany, emission limits of 800 mg/m^3 for existing plants and 500 mg/m3 for new plants has resulted in the development by Krupp Polysius of trials to combine multi-stage combustion (MSC) with the SNCR process (Erpeldin, 2000). The process involved injecting an ammonium based solution at various points of the calciner to find the best place to introduce the solution within a suitable temperature window. The results showed that the best location for the NOx reduction process was obtained by injecting the solution before and after the deflection chamber. The trials were carried out at three plants of different sizes. At emission levels for MSC without ammonia between 400 and 800 mg, 250 mg was achieved corresponding to a reduction rate of between 38 and 68 percent.

CEMENT PLANT OPERATIONS AND EQUIPMENT IN ELLIS COUNTY

The installed equipment at the three cement plants in Ellis County was described in the previous section.

Table 3-2 summarizes the current situation.

Table 3-2. Control technology used in Ellis County cement plants.

Company Name	Unit	Process	Current NOx Control Technology	2002 NOx Emissions (tons/yr)
Ash Grove Cement[1]	Kiln 1	Wet Process	ChemStar, MKF (tires)[3]	823.9
Ash Grove Cement	Kiln 2	Wet Process	ChemStar, MKF (tires)[3]	829.2
Ash Grove Cement	Kiln 3	Wet Process	ChemStar, MKF (tires)[3]	918.6
				Plant Total 2,571.7
TXI Operations, L.P.	Kiln 1	Wet Process	ChemStar	1,010.2
TXI Operations, L.P.	Kiln 2	Wet Process	ChemStar	24.3
TXI Operations, L.P.	Kiln 3	Wet Process	ChemStar	375.6
TXI Operations, L.P.	Kiln 4	Wet Process	ChemStar	988.4
TXI Operations, L.P.	Kiln 5	Dry Process[2]	LNB	1,822.7
				Plant Total 4,221.2
Holcim Texas L.P.	Kiln 1	Dry Process[2]	LNB	1,909.7
Holcim Texas L.P.	Kiln 2	Dry Process[2]	LNB	2,265.1
				Plant Total 4,174.8

[1] Formerly North Texas Cement Company.

[2] Precalciner Kiln.

[3] TNRCC confirmed that North Texas Cement (Ash Grove) meets the criteria of having mid-kiln firing and low NOx-burners, Letter from Richard L. Hughes, September 20, 2000.

The Ash Grove Cement and TXI plants predominantly use wet process kilns. In 2002 wet process kilns, for which control options are more limited, produced about 45% of all cement plant NOx emissions.

POTENTIAL ADDITIONAL CONTROLS ON ELLIS COUNTY CEMENT PLANTS

Our evaluation of potential controls for the cement plants in Ellis County is based on the experience of other plants in the U.S. and Europe as reported in the literature. For the purposes of this report, the term "technically feasible" applies to a control method or technology has been applied to other cement kilns, has been demonstrated to be successful in reducing NOx emissions, and appears to be feasible for similar equipment and processes in use in Ellis County. At this level of analysis, where detailed information on plant design, equipment and operations is not available, conclusions on technical feasibility are necessarily preliminary and have significant uncertainty."

Wet Kilns

Seven of the ten kilns in Ellis County are wet process kilns. As discussed earlier, wet process kilns are an older cement production technology with smaller production capacity requiring 30 to 100 percent more thermal energy per unit of production than dry kilns (EC/R, 2000, reported 33% as an average).

Wet kilns also produce a greater volume of exhaust gas than dry kiln processes. Since NOx formation is directly related to fuel combustion, wet kilns also produce more NOx per unit of production. Conversely, any reduction in the amount of fuel burned in wet kilns will also lower NOx emissions per unit of clinker. To address energy efficiency issues and the higher emission rates from wet process kilns in Europe, observers expect most wet process kilns to be converted to dry process kiln systems when the plants are renewed (IPPCB, 2000).

All wet kilns in Ellis County already use ChemStar and some have low-NOx burners,[8] but other opportunities for control exist. If applied, strategies such as combustion zone monitoring/regulating excess air, MKF, and supplementing fuels with TDF, will both lower NOx and improve fuel efficiency. Low NOx burners can also be effective where not currently installed.

Our review indicates that neither SNCR nor SCR is currently available for wet kilns. Oxidation (LoTOx System) shows some potential, but has not yet been applied to any type of cement plant. We recommend that this process be investigated for application on the wet process kilns.

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[8] TNRCC confirmed that North Texas Cement (Ash Grove) meets the criteria of having mid-kiln firing and low NOx-burners, Letter from Richard L. Hughes, September 20, 2000.

Dry Kilns

All dry kiln units in Ellis County use low NOx burners, however the newer preheater/precalciner kiln designs in Ellis County provide additional opportunities for NOx control. In addition to most the control methods available to wet kiln processes, NSCR appears technically feasible pending a more thorough engineering review of the plants. While SCR has not been applied to a U.S. cement plant and poses significant technical challenges, it has had one apparently successful demonstration in Europe. More important, SCR is a proven technology on other types of facilities with a significantly greater emission reduction potential than other technologies available for cement plants. While we consider it only "potentially feasible" at this point, its emission reduction potential is too high to be set aside permanently, especially if significant NO_x controls are required to attain air quality standards.

Potential Emission Reductions

The potential emissions reductions that could be achieved by applying the technologies described above to the kiln operations in Ellis County are shown in Table 3-3. For simplicity in presenting the reduction potential of these technologies the emissions reductions shown in Table 3-3 are based on the average emission reduction potential of the technologies from Table 3-1. Actual reductions may be larger or smaller, depending on plant-specific conditions and engineering considerations, including the physical plant layout.

For determining the total emissions reductions feasible, it was assumed that the existing wet kilns at TXI Operations could achieve an additional 30 percent reduction (using either mid-kiln firing or other combustion modification technology), the amount required by Chapter 117, if the emission levels cannot be met. This assumption was not applied to the Ash Grove facility as Mid-Kiln firing is already in use at this facility. Furthermore, emissions of NOx per ton of clinker appear to be somewhat less at the TXI operations, however specific production from the TXI operations were not available from the TCEQ. Again, our analysis and conclusions must be considered preliminary, since they are based on general information about the facilities in Ellis County and do not involve a detailed engineering analysis of plant equipment or operations.

For the dry kilns, potential emissions reductions were calculated for both the SNCR process and the SCR process, though only one method would be applied.

Overall, applying the technology described in this report could result in the reduction on NOx ranging from 1,200 tons per year to over 5,500 tons per year. The successful application of the technologies will depend on the applicability of the various control techniques to each individual kiln operation. This analysis did not include an engineering feasibility but rather an identification of the potential control technologies that should be further investigated for application in Ellis County.

Table 3-3. Potential emission reductions from cement plants in Ellis County.

Company	Unit	2002 NOX Emissions (tons/yr)	Potential NOx Control Technology Reductions					
			Process[3]		SNCR		SCR[4]	
			%	T/Y	%	T/Y	%	T/Y
Ash Grove[1]	Kiln 1 (Wet)	823.9						
Ash Grove[2]	Kiln 2 (Wet)	829.2						
Ash Grove[3]	Kiln 3 (Wet)	918.6						
		2,571.7		**0.0**				
TXI Operations	Kiln 1 (Wet)	1,010.2	30	303.1				
TXI Operations	Kiln 2 (Wet)	24.3	30	7.3				
TXI Operations	Kiln 3 (Wet)	375.6	30	112.7				
TXI Operations	Kiln 4 (Wet0	988.4	30	296.5				
TXI Operations	Kiln 5 (Dry)[2]	1,822.7	30	546.8	45	820.2	80	1458.2
		4,221.2		**1266.4**		**820.2**		**1458.2**
Holcim	Kiln 1 (Dry)[2]	1,909.7	30	572.9	45	859.4	80	1527.8
Holcim	Kiln 2 (Dry)[2]	2,265.1	30	679.5	45	1019.3	80	1812.1
		4,174.8		**1252.4**		**1878.7**		**3339.8**

[1] Formerly North Texas Cement Company.

[2] Dry Process is Precalciner Kiln.

[3] Process modifications are assumed to achieve an average reduction of 30 percent.

[4] SCR is considered "potentially feasible" and is presented here for completeness.

4. EVALUATION OF THE COST OF NOx EMISSION CONTROLS

INTRODUCTION

This cost-effectiveness analysis builds on the conclusions of the previous sections. In the previous section we examined the range of possible and probable emissions reduction measures that may be applicable to cement plants in Ellis County. As noted in that section, and repeated here, the emissions reductions, appropriate control measures, and the related costs cannot be defined fully within the context of this study. Such in-depth engineering design assessment would be the next step in furthering emissions reductions from these sources, and would have to be carried out in collaboration with the individual facilities. This overall study is intended to further the necessary constructive dialog between the stakeholders, leading to the possible additional emissions reductions from these facilities.

All information for this study has been derived from public sources such as facility permit files and various TCEQ reports. Shortcomings in those data sets may be reflected in this report. Further detailed information, derived from the facilities described in this and previous reports, would be a wise next step in assuring the accuracy of the data used herein.

The focus is on cement plants because they are the predominant source of NO_x emissions from stationary sources in Ellis County. Each technically feasible control method/technology discussed in the previous section is analyzed. To the extent possible, given available information, a cost estimate is made for each combination of a technically feasible control method and the specific equipment and process in use at the three cement plants in Ellis County. The steps in the evaluation are:

1. Select a cement plant unit from Table 3-2 in the previous section.
2. Select a technically feasible control method for that equipment from Table 3-3 of the previous section.
3. Estimate the annual cost of applying the feasible control method to that piece of equipment using available information and the methodology described below.
4. Apply the estimated cost of control to the range of emissions reductions estimated in Table 3-3 of the previous section to calculate a range of cost-effectiveness stated as dollars per ton of NO_x emissions reduced.

This report makes cost estimates at what EPA calls the "study level" of analysis, which produces an accuracy level of, at best, + or - 30% (EPA Air Pollution Control Cost Manual, Sixth Edition, p. 2-3, Figure 2-1). Since cost-effectiveness calculations apply cost estimates to the range of emission reductions estimated in the previous section, all the uncertainties and limitations with emission reduction estimates that were described in the previous section apply equally to the cost-effectiveness numbers in this report.

At these levels of analysis, the capital cost estimates do not address specific retrofit considerations for the Ellis County plants. There is not enough information available to uncover potential hidden costs of a specific installation on a specific unit. EPA guidance notes that a retrofit factor of up to 50% of the capital cost of the control system can be justified on a case-by-case basis, but that it is also important to avoid over-estimates (Control Cost Manual, p. 2-28). Since this study has no means of developing a retrofit factor for each technology-unit combination, we have chosen to apply an across-the-board contingency factor of 20%. Specific considerations for retrofit requirements are identified in the discussion for each control technology. The contingency factor may or may not be adequate to cover plant and unit specific issues.

In summary, these estimates should be considered rough estimates of the actual cost-effectiveness of emissions reductions measures, should these control methods be applied to Ellis County cement plants.

COST CALCULATION METHODOLOGY

The approach to calculating cost-effectiveness is based on, but not identical to, the cost-calculation methodology used in EPA's 1994 "Alternative Control Techniques Document—NO_x Emissions From Cement Manufacturing" (ATC) and the 2000 review and update, "NO_x Control Technologies for the Cement Industry - Final Report" (hereafter "EC/R", the consultant that prepared the report for EPA). The methodologies used in these reports were, in turn, based on the EPA Air Pollution Control Cost Manual, Fifth Edition. EPA is in the process of assembling a Sixth Edition of the cost manual, but at present it contains no information on NO_x control at cement plants. The approach used here uses the same cost parameters as the EPA documents but, as noted above, applies estimated costs as much as possible to specific Ellis County cement plant units rather than "model plants".

The cost parameters and the sources of the values used in this report are listed in Tables 4-1 and 4-2. The reports mentioned above applied assumptions to some cost parameters and used national data on others. We have applied the same assumptions as the authors of the EPA reports, but updated the information used in some cases to make them more current and specific to Texas. The parameters that use Texas-specific information are identified in Table 4-2. For most control technologies we applied the most recently available purchased equipment costs (PEC) for control equipment from the EPA reports. References are included in the cost calculation tables in Appendix A. Our review showed that in some cases EPA obtained their PEC from early-1990's vintage vendor estimates and then reused these estimates in the 2000 report. It was not possible within the scope of this analysis to comprehensively update EPA estimates with more recent information from vendors. While we relied heavily on published EPA material, we also reviewed European studies, other U.S. reports and articles, and several recent U.S. air permits to verify that the cost estimates in this report are generally within the ranges reported in the literature. Since there was little cost information in the literature on selected catalytic reduction (SCR) in these applications, we also contacted a vendor who recently provided quotes on cement plants.

Capital Cost Estimation

Table 4-1. Capital investment components of cost estimates.

Parameter	Value	Source
Purchased equipment cost (control device and auxiliary equipment)	Will vary by equipment	Best available, priority on information from public records
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)	45% of PEC	1994 ATC, also in EC/R report
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)	33% of PEC	1994 ATC, also in EC/R report
Contingencies	20% of PEC	1994 ATC, also in EC/R report
Sales tax	3% PEC	6th Edition cost manual, Chapter 2, Table 2-4
Freight	5% PEC	Same
Production downtime	Two days plus $77, the market value per ton of clinker in 2003	Downtime from EC/R report, market value from http://minerals.usgs.gov/minerals/pubs/commodity/cement/170303.pdf
Total capital costs (sum of all above)		

Purchased equipment costs for some control methodologies technologies depend on specific characteristics of the units, particularly the production capacity and baseline energy efficiency of the kiln. Since some of this information is not available for this study, assumptions had to be made. These are explained and documented on a case-by-case basis.

If actual direct and indirect installation costs are available, they are used instead of the default values listed in Table 4-1. A contingency factor of 20% is used to account for problems associated with retrofitting technologies on specific units. Actual costs may be larger or smaller. Downtime is assumed for all applications, but it may be an avoidable cost if controls are installed in conjunction with other maintenance shutdowns.

The total capital investment is the sum of the direct cost (which is the purchased equipment costs and direct installation costs), indirect installation costs, contingency costs, sales taxes, freight, and production downtime. Total capital costs are carried forward in the process and used for calculating overhead, capital recovery and other elements of annual cost.

Annual Operating Costs

Annual operating costs are composed of the direct operating costs of materials and labor for maintenance, operation, utilities, material replacement and disposal and the indirect operating charges, including plant overhead, general administration, and capital recovery charges.

Annual utility costs include both the cost of operating control equipment and post-retrofit changes in fuel consumption. Control strategies can increase or decrease overall fuel consumption, but strategies such as excess air monitoring and control and mid-kiln firing (MKF) reduce NO_x indirectly by improving overall fuel efficiency. These control approaches offset other costs with fuel savings. Ellis County cement plants are permitted to use a mix of fuels. Since neither the mix nor quantity of typical fuel use is available for this study, baseline and future fuel costs are necessarily based on case-by-case assumptions.

The literature shows that plants in some areas are paid tipping fees to "dispose" of waste tires (tire-derived fuels or TDF), while other plants have to buy tires. The market is fluid and depends heavily on public policy and subsidies. We were unable to identify the "cost" to cement plants of TDF in Texas and therefore have assumed that they can be obtained free by the plants in Ellis County.

Indirect annual costs such as insurance, taxes, and overhead (both labor and materials) are estimated using values from EPA's Cost Manual.

The capital recovery factor (CRF) used in this analysis assumes a 15-year equipment lifetime and a discount interest rate of 7.7%. These assumptions were taken from Iowa's recent permit evaluation on the Lehigh facility (see discussion from pervious section).

Table 4-2. Annual cost components.

Direct Costs		**Value**	**Source**
Utilities	Coal	23.47 per short ton	2001 price from http://www.eia.doe.gov/cneaf/coal/page/acr/table35.html
	Electricity	$0.056 per kw-hr	2003 prices in TX for industrial users per http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls
	Nat. gas	$3.40 per 1000 cubic feet	2002 price in TX for industrial users per http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_stx_a_d.htm
	Tires	$0	Chosen because we were unable to find information on waste tire values in Texas
Labor	Operating labor	12.47 per hour	TX labor rates from 2002 survey for kiln operators, see http://www.bls.gov/oes/2002/oes_tx.htm#b51-0000
	Supervising labor	15% of operating labor	EC/R report, p 87
Maintenance	Maintenance labor	19.18 per hour	TX labor rates from 2002 survey for industrial machinery mechanics, http://www.bls.gov/oes/2002/oes_tx.htm#b51-0000

Direct Costs		Value	Source
	Maintenance materials	100% of maintenance labor	EC/R report, p 87
Total direct cost			
Indirect costs			
	Overhead	60% of all labor categories and materials	6th Edition cost manual, Chapter 2, p. 2-34
	Property tax	1% of total capital cost	6th Edition cost manual, Chapter 2, p. 2-34
	Insurance	1% of total capital cost	6th Edition cost manual, Chapter 2, p. 2-34
	Admin. Charges	2% of total capital cost	6th Edition cost manual, Chapter 2, p. 2-34
Total indirect cost			
	Capital recovery	Assume 7.7% interest rate and a 15-year equipment life. CRF = 0.1147 per dollar	The capital recovery factor (CRF) is multiplied times total capital cost to calculate annual equipment payments over the equipment life. CRF = I(1+I) n /((1+I) n – 1), where "I" is annual interest rate in percent and "n" is equipment life in years
Total Annual Costs = Total DC + Total IC+ Capital recovery			

COST-EFFECTIVENESS CALCULATION METHODOLOGY

Annual costs are used in two ways in this report. First, and specific to the cement plants themselves, the annual cost of control is divided by the estimates of annual emission reductions in order to express cost effectiveness as annual cost per annual emissions reductions (CE = $/ton). Second, and to put the cement kiln cost-effectiveness results presented above into context, we have also summarized annualized NO_x control strategy cost effectiveness estimates for a wide variety of control measures considered in the development of ozone attainment strategies in various U.S. cities.

COSTS OF NOx CONTROL APPROACHES

General Considerations

The capital and operating costs were estimated for each of the control technologies that were deemed technically feasible in the previous section. In addition, we have performed a rough estimate of the cost and cost-effectiveness of Selective Catalytic Reduction (SCR), even though it was classified as "potentially feasible". Because the ChemStar process is used on each of the wet kilns in Ellis County, the cost of this process was not estimated

In order to make the analysis more relevant to the Portland Cement facilities in Ellis County, we applied various technologies to specific kilns and did so with consideration of the equipment and

NO_x control methods that are already in place at each kiln. Although estimates are not provided for all technologies at each kiln, the general cost and cost-effectiveness ranges would generally apply to all kilns. The exception is where a particular technology is not applicable to a particular kiln, i.e., the application of SNCR to wet kilns. All assumptions and costs identified with this analysis are included in the cost evaluation sheets contained in Appendix A.

Some information on the costs of controls was based on assumptions that were necessary because certain information was not available from the TCEQ for the specific kilns in operation in Ellis County. For example, we were able to obtain material throughput in tons of clinker processed per year for the Ash Grove kilns and the Holcim kilns but not the kilns at TXI Operations. We were also not able to obtain information on the amount and types of fuel used for the kilns at each of the three plants. Assumptions for these parameters as well as assumptions on specific equipment such as the use of direct-fired burners at the wet kilns were also made.

As discussed in the previous section, oxidation (LoTOx System) shows some potential, but has not yet been applied to any type of cement plant. Accordingly, we have not included this technology in our cost estimates. As a result we believe that some of these technologies should be more fully explored with specific attention to the plant configurations and operating conditions at each kiln.

Low NOx Burners

Low NO_x burners are in use at TXI Operations and on the dry kilns at the TXI and Holcim facilities. For reasons discussed in Task 3, low NO_x burners require an indirect firing configuration. It is our understanding that the wet kilns at TXI Operations are therefore indirect-fired kilns.[1] Because the wet kilns at the Ash Grove plant have mid-kiln firing, a technology that has the potential to provide greater NOx emission reductions, we have not estimated the cost of low-NOx burners for this analysis.

Mid-Kiln Firing

As discussed in the previous task, strategies such as MKF, and supplementing fuels with TDF, will both lower NO_x and improve fuel efficiency. The technology can be applied to wet kilns and long dry kilns, but is not considered a candidate control method for the modern dry kilns in use in Ellis County. Mid-kiln firing is currently being used at the Ash Grove Cement facility. In addition, this technology was studied at the TXI facility for all four wet kilns from July to November of 2002.The most significant costs associated with this process are those for kiln modifications necessary to facilitate the secondary fuel, and the solid fuel conveying system. If these modifications were made in 2002 and were still in place at TXI, the cost for implementing this control method at TXI would be significantly lower than shown in Table 4-3 and the range of cost-effectiveness would be more favorable. It is our understanding that the control equipment is no longer installed at these kilns.

The capital and annual operating costs used in this analysis was obtained from the EC/R report on NO_x Control Technologies for the Cement Industry. The cost includes a fuel credit for the

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[1] Personal conversation with Randy Hamilton, TCEQ, April 9, 2004.

fuel that is replaced with waste tires as well as a tipping fee. Again the assumptions used for these credits are from the EC/R report and do not necessarily reflect actual fees or fuel credits from the specific plants in Ellis County. The negative range of cost-effectiveness shown below reflects the large credits for the fuel and tipping fees as well as the variability in emission reductions that can be achieved by this technology in different installations.

Table 4-3: Cost of mid-kiln firing.

Company Name	Unit	Process	NOx Reduction (Tons/Yr)	Capital Cost	Operating Cost	Cost-Effectiveness ($/Ton)
TXI Operations, LP.	Kiln 1	Wet	283 - 596	$3,227,619	(757,753)	($650 - $1,370)
TXI Operations, LP.	Kiln 2	Wet[1]				
TXI Operations, LP.	Kiln 3	Wet	105 - 222	$3,227,619	(757,753)	($1,749 - $3,685)
TXI Operations, LP.	Kiln 4	Wet	277 - 583	$3,227,619	(757,753)	($665 - $1,400
Total			**665 - 1,401**	**$9,682,858**	**(2,273,258)**	**($650 - $3,685)**

Notes

[1] Kiln 2 emissions are very low indicating that the unit was not in full operation during 2002. Therefore, cost estimates were not included for this kiln.

Multi-stage Combustion (MSC)

Although not discussed as a potential technology in the previous task, MSC is a technology that is available for some preheater/precalciner kilns. Several kilns in the US have recently been retrofitted with these "low NO_x" precalciners. Preliminary information indicates a noticeable reduction in NO_x per ton of clinker (up to 46 percent) without causing excessive coating difficulties in the kiln. (EC/R).

It is not possible to use "staged combustion" on preheater kilns that are firing fuel in the riser since in staged combustion it is necessary to add the fuel in an oxygen deficient atmosphere and then supply additional combustion air to fully combust the fuel. Preheater kilns do not have tertiary air ducts to supply the additional combustion air. The air for combustion of the secondary fuel must come through the kiln, which precludes introducing the secondary fuel into an atmosphere with insufficient oxygen for complete combustion. With MSC in a precalciner, emissions reductions in the range of 30 to 40 percent have been reported when burning tire derived fuel (EC/R, 2000).

Biosolids Injection Process (BSI)

The application of this process to preheater/precalciner kilns has been applied in the U.S. and shows promise for reducing NO_x emissions. With this technology, dewatered sewage sludge is added to the mixing chamber of the calciner. The dewatered biosolids provide a source of ammonia, producing an SNCR-like reaction to reduce NO_x. The costs associated with installing this technology include the sludge system and the sludge conveying system. This technology can be very attractive from a cost standpoint if the cement plant is paid a tipping fee to dispose of the sludge. For the purpose of this analysis, a tipping fee of $5.00 per wet ton was used. This is an average of tipping fees that range from $0.00 to $10.00 per wet ton (EC/R, 2000). The capital and annual operating costs used in this analysis was obtained from the EC/R report on NO_x

Control Technologies for the Cement Industry. Table 4-4 summarizes the cost for this technology.

Table 4-4. Cost of BSI.

Company Name	Unit	Type	NOx Reduction (Tons/Yr)	Capital Cost	Operating Cost	Cost-Effectiveness ($/Ton)
TXI Operations, LP.	Kiln 5	Dry[1]	273 - 547	$1,245,721	($482,537)	($621) - ($1,242)
Holcim Texas LP	Kiln 1	Dry[1]	287 - 573	$987,556	($492,863)	($663) - ($1,325)
Holcim Texas LP	Kiln 2	Dry[1]	340 - 680	$947,392	($494,470)	($568) - ($1,136)
Total			**900 - 1,800**	**$3,180,669**	**($1,469,870)**	**($568) - ($1,325)**

Notes

[1] Dry Process is Precalciner Kiln

Selective Noncatalytic Reduction (SNCR)

As noted in Task 3, our review indicates that neither SNCR nor SCR is currently available for wet kilns. However, SNCR has demonstrated significant reductions of NO_x when applied on numerous operating dry precalciner kiln configurations in Europe and on tests on several plants in the U.S. The primary information on capital cost for this analysis was from the submittal from Holcim to the TCEQ. The analysis was received by the TCEQ on May 19, 2003 and was submitted as part of an analysis of potential emission reduction techniques to demonstrate that the facility could modify its operations without an increase in emissions [2]. The cost estimates are based on a urea based systems with a removal efficiency of 20 percent. Therefore the costs include of a complete urea delivery and injection system. Because SNCR requires availability of a section of kiln with the proper temperature and residence time as well as a determination of the amount of ammonia injected, (specifically the NH3/NO_x molar ratio), the application of this technology to a specific kiln will determine the level of reduction possible. Therefore, the costs of this technology will vary depending not only on the removal efficiency but also the reagent utilization.

To provide a basis of comparison, we obtained the cost estimates for the SNCR installation at the Lehigh Cement Company plant in Mason City Iowa. The PEC for this plant was $1,083,666, somewhat less that the $1,201,496.00 estimate used in this analysis. The Lehigh system is based on baseline NO_x emissions of 3.8 lb/ton of clinker and 25 percent NO_x reduction efficiency. Based on this comparison, the capital cost estimates in this report for SNCR appears reasonable.

It should be noted that the application of this technology has resulted in achieving even higher levels than included in this analysis. For example, one demonstration of urea on a precalciner kiln achieved over 80 percent reduction (NESCAUM, 2000). As a result we believe that the associated reductions will be at the upper end, and the cost-effectiveness near the lower end, of the range identified in Table 4-5.

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[2] Appendix G, Tier 3 Cost Estimate SNCR for NOx, Holcim May 19, 2003.

Table 4-5. Cost of SNCR.

Company Name	Unit	Type	NOx Reduction (Tons/Yr)	Capital Cost	Operating Cost	Cost-Effectiveness ($/Ton)
TXI Operations, LP.	Kiln 5	Dry[1]	182 - 911	$3,948,966	$1,770,191	$2,439 - $12,197
Holcim Texas LP	Kiln 1	Dry[1]	191 - 955	$3,690,801	$1,759,864	$2,266 - $11,432
Holcim Texas LP	Kiln 2	Dry[1]	227 - 1,133	$3,650,637	$1,758,258	$1,022 - $9,611
Total			**182 - 1,133**	**$11,290,404**	**$5,288,313**	**$1,022 - $12,197**

Notes

[1] Dry Process is Precalciner Kiln

Combination of Technologies

The combination of multi-stage combustion (MSC) with SNCR can achieve significant reductions at a reduced cost compared to SNCR alone. Trials were conducted on three plants of different sizes in Germany by Krupp Polysius, AG. The trials were carried out on precalciner kilns that were equipped with MSC and that injected ammonia based solution at various points of the calciner. The system used a 25 percent ammonia solution and a film developer wastewater enriched to 5 percent with urea. The best results were achieved by injecting the solution before and after the deflection chamber. The advantage offered by this combination of technologies is that cost effectiveness improves when compared to SNCR alone. According to Dr. R. Erpeldin (2000) of Krupp Polysius AG, the higher investment costs for the ammonia system (above that for just MSC) are compensated by lower costs for the fuel and the ammonia carrier. The best results were achieved when the total emission reduction rates were set above 35 – 45 percent. Using the results for these trials, the cost reduction for this combination of technologies showed approximately a 50 percent reduction in the operating cost over SNCR alone. However, this savings is partially offset by the upfront capital investment for the MSC system. Further investigation of this combination of technologies is suggested for the specific preheater/precalciner kilns at TXI Operations and Holcim Cement.

Selective Catalytic Reduction (SCR)

As discussed in the previous task, SCR has not been applied on any U.S. cement plants. The track record at cement plants worldwide is also small, since we identified success at only one cement plant in Europe. However, it was our judgment that SCR is worth including in this preliminary analysis because of its promise; namely the excellent track record of SCR technology in other industries and the significant emission reductions that can be achieved.

Capital costs of this control approach are significantly higher than the other technologies primarily due to the cost of an SCR unit, ammonia storage tank, and an ammonia heating/vaporization injection system along with equipment needed for reheating flue gases to an appropriate temperature depending on the placement of the system in the cement production process. We obtained capital cost estimates from the Alternative Control Techniques Document- NO_x Emissions from Cement Plants published by EPA in March 1994. Because SCR installations require considerable space and are often custom designed, retrofit costs can be very significant, considerably more than the 20% contingency factor we have applied. An estimate of retrofit costs would be an important issue should there be a more refined level of analysis of the technical feasibility and cost of SCR on these plants.

The NO_x reduction achieved with SCR technology depends on the amount of ammonia injected, (specifically the NH3/NO_x molar ratio), and the gas phase residence time in the SCR reactor. The SCR equipment costs from the EC/R report were based on application on a dry kiln with exhaust gases at 350 °C (660 °F) and a design NO_x removal efficiency of 80 percent. The equipment cost estimate included SCR catalysis, SCR reactor, gas/gas heat exchanger, heater, ammonia injection grid, ammonia storage tank, ammonia vaporizer and supply unit, induced draft fan, instrumentation and all piping and ductwork. However, depending on the location of the SCR unit in the kiln process, the additional heating may not be required. This was the case with the experience at the Solenhofen plant in Germany (discussed in the previous section). As a result the costs used for this analysis could be lower. The experience in Germany has also shown that a need for continuous cleaning of the catalyst that would increase the operating cost of this system.

As mentioned earlier, this technology has not been applied in the U.S.; however, the state of New York is evaluating the SCR process for application at the new St. Lawrence Cement facility. A cost estimate from KWH Catalysts was provided for this facility.[3] The capital cost estimate for this plant was $9,000,000, which is lower than the $11,900.000 estimate used in this analysis. The estimate for the St. Lawrence facility was based a "high-dust" installation and an exhaust volume of 350,000 m^3/hour. This tends to confirm that equipment costs for such installations would be lower because reheating the exhaust gases is not necessary.

Despite its high capital cost, the greater NO_x removal efficiency with this technology results in the cost-effectiveness range, expressed as dollars per ton of NO_x reduced that is similar to the mid- range of cost-effectiveness for SNCR.

Table 4-6. Cost of SCR.

Company Name	Unit	Type	NOx Reduction (Tons/Yr)	Capital Cost	Operating Cost	Cost-Effectiveness ($/Ton)
TXI Operations, L.P.	Kiln 5	Dry[1]	1458 - 1832	$29,773,249	$5,191,367	$4,970 - $5,902
Holcim Texas L.P.	Kiln 1	Dry[1]	1528 - 1814	$27,966,093	$7,023,081	$5,639 - $6,696
Holcim Texas L.P.	Kiln 2	Dry[1]	1812 - 2152	$27,684,944	$5,107,835	$3,849 - $4,571
Total			**4798 - 5798**	**$85,424,286**	**$17,322,282**	**$3,849 - $6,696**

Notes

[1] Dry Process is Precalciner Kiln

NO_x CONTROL STRATEGY COST-EFFECTIVINESS COMPARISONS

To put the cement kiln cost-effectiveness results presented above into context, we present here a brief summary of NO_x control strategy cost effectiveness estimates for a wide variety of control measures considered in the development of ozone attainment strategies in various U.S. cities. We reviewed cost-effectiveness results for measures adopted and/or studied in Texas (including Dallas-Fort Worth Area, Houston-Galveston Area, and San Antonio), Tennessee, West Virginia,

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[3] Personal conversation with Tom Luga of KWH Catalysts, Inc, April 7, 2004.

Virginia, as well as those adopted and/or used by the Environmental Protection Agency (EPA) and California Air Resources Board (CARB). Cost-effectiveness values presented here are based on studies listed in Table 4-8. The control measures examined in these studies are used here as examples for comparison purposes only: they are not intended to represent a comprehensive list of all the available control measures that might be applicable to the Dallas – Ft. Worth area.

Cost effectiveness ranges for various types of control measures examined in the studies listed in Table 4-8 are summarized in Table 4-7. For purposes of comparison with the cement kiln NO_x measures described in the previous sections, only cost-effectiveness estimates specifically for NO_x are included in Table 4-7: estimates included in the Table 4-8 references that were stated only on a (NO_x + VOC) $/ton basis were not included.

Table 4-7. Summary of average cost effectiveness estimates for various types of control measures from studies listed in Table 4-8.

Control Measure Category	NO_x Cost Effectiveness ($/ton)	
	Minimum	Maximum
Mobile sources: on-road fuel and retrofit programs	$600	$65,852
Mobile sources: other on-road measures (vehicle standards, I/M programs, TCMs, etc.)	$100	$75,000
Off-Road mobile sources: emission standards, retrofits, etc.	$200	$13,000
Industrial and area sources: utility NO_x limits, other industrial NO_x controls	$1,200	$4,600
Cement kiln controls[4]	$450	$1,713

Given the wide range of control measures examined in the studies described above and the unique conditions factored into each study, it is not surprising that the cost-effectiveness values in Table 4-7 span a wide range. Cost-effectiveness estimates for cement kilns (both those listed in Table 4-7 and the more detailed estimates discussed in previous sections) appear to be in line with those of other stationary source control measures and are significantly less expensive than some of the more costly mobile source measures. It should be noted that the $/ton estimates shown here do not reflect the potential contribution to total NO_x reductions which might be achieved by the various control measures if they were to be implemented in the Dallas – Ft. Worth area. Some control measures, while not inexpensive on a $/ton basis, may nevertheless be of interest to planners because they have the potential to result in significant total tonnage reductions.

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[4] Two of the studies listed in Table 7, (EPA, 2004; NESCAUM, 2000) included information on the cost effectiveness of cement kiln NOx control measures.

Table 4-8. Alternative control measure cost-effectiveness studies.

Study	Source	Reference
NCTCOG	"Evaluation of Attainment Control Strategies for the Dallas-Fort Worth State Implementation Plan", report to the North Central Texas Council of Government (NCTCOG) by ENVIRON	ENVIRON (2000)
H-GAC	"Initial Evaluation of Emission Reduction Potential of Candidate Measures to Obtain N0x Reductions in the Houston-Galveston Area", report for the Houston-Galveston Area Council (HGAC) by ENVIRON, July 25, 2000.	ENVIRON (2000)
San Antonio EAC	"1st Biannual Report: The Early Action Compact for the San Antonio Metropolitan Area," prepared by the Alamo Area Council of Governments, June 2003	(San Antonio EAC, 2003);
Tennessee EAC	"Emission Inventories and Potential Emission Control Strategies for Ozone Early Action Compact Areas in Tennessee," prepared for Tennessee Dept. of Transportation and Dept. of Environment and Conservation, prepared by University of Tennessee, April 13, 2003	Tennessee EAC, 2003
Berkeley Jefferson Counties EAC	"Evaluation of Emissions Control Technologies under Consideration for the Berkeley Jefferson Counties Early Action Compact," report to the Wilbur Smith Associates by ENVIRON, March 2004	ENVIRON (2004)
Winchester Frederick County EAC	Evaluation of Emissions Control Technologies under Consideration for the Winchester Frederick County Early Action Compact," report to the Wilbur Smith Associates by ENVIRON, December 2003	ENVIRON (2003)
CARB Control Measures	"Initial Statement of Reasons for Adopting More Stringent Emission Standards for 2007 and Subsequent Model Year New Heavy-Duty Diesel Engines," staff report prepared by the California Air Resources Board (CARB), September 2001	CARB, 2001
EPA Mobile Control Measures	"Regulatory Impact Analysis – Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements," EPA420-R-99-023, Environmental Protection Agency, December 1999	EPA, 1999
EPA Point Control Measures	"Identification and Discussion of Sources of Regional Point Source NOx and SO2 Emissions Other Than EGUs," technical support document prepared by EPA, January 2004, and EPA's AirControlNET Database Software on Cost Strategies and Costing Analysis	EPA, 2004
NESCAUM NOx Control Study	"Executive Summary: Status Report on NOx Control for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost-Effectiveness," prepared by Northeast States for Coordinated Air Use Management, December 2000	NESCAUM, 2000

ADDITIONAL REFERENCES

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EPA. 1995. Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, USEPA, AP-42 Fifth Edition, January.

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NESCAUM. 2000. Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December.

SEPA. 2000. Per Junker, Reduction of Nitrogen Oxides with SNCR at Slite Cement Plant, Swedish Environmental Protection Agency, March.

APPENDIX A

COST CALCULATION WORKSHEETS

CALCULATION SHEET FOR CAPITAL COST

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 1

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$1,490,000
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 670,500
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 491,700
Contingencies		Default is 20% of PEC	$ 298,000
Sales tax		3% PEC	$ 44,700
Freight		5% PEC	$ 74,500
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 158,219
	Capital cost		$ 3,227,619
	Annual cost assuming 15 year equipment life		**$ 215,175**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

CALCULATION SHEET FOR CAPITAL COST

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 3

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$1,490,000
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 670,500
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 491,700
Contingencies		Default is 20% of PEC	$ 298,000
Sales tax		3% PEC	$ 44,700
Freight		5% PEC	$ 74,500
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 158,219
	Capital cost		$ 3,227,619
	Annual cost assuming 15 year equipment life		**$ 215,175**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

CALCULATION SHEET FOR CAPITAL COST

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 4

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$1,490,000
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 670,500
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 491,700
Contingencies		Default is 20% of PEC	$ 298,000
Sales tax		3% PEC	$ 44,700
Freight		5% PEC	$ 74,500
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 158,219
	Capital cost		$ 3,227,619
	Annual cost assuming 15 year equipment life		**$ 215,175**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

ANNUAL COST WORKSHEET

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 1

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton		$ -
	Electricity	$0.056 per kw-hr		$ -
	Nat. gas	$3.40 per 1000 cubic feet		$ -
	Tires	$___ per ton		$ -
Utilities subtotal				$ -
Labor	Operating labor	12.47 per hour		$ 30,400.00
	Supervising labor	15% of operating labor		$ 4,560.00
Maintenance Labor	Maintenance labor	19.18 per hour	1095	$ 21,002.10
	Maintenance materials	100% of maintenance labor		$ 21,002.10
Labor subtotal				*$ 76,964.20*
Disposal Revenue				*$ (510,000.00)*
Fuel Credit				*$ (500,000.00)*
Total annual direct cost				**$ (933,035.80)**
Total from capital cost worksheet				**$ 3,227,619.18**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 46,178.52
	Property tax	1% of total capital cost		$ 32,276.19
	Insurance	1% of total capital cost		$ 32,276.19
	Admin. Charges	2% of total capital cost		$ 64,552.38
Total annual indirect costs				$ 175,283.29
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF x total capital		$ 370,207.92
Total annual cost, TAC=DC+IC+capital recovery				$ (387,544.59)

Cost-Effectiveness ($ per ton NOx reduced)	High	$ (1,370)
	Low	$ (650)
Cost Per Ton of Clinker		$ (1.03)

ANNUAL COST WORKSHEET

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 3

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton		$ -
	Electricity	$0.056 per kw-hr		$ -
	Nat. gas	$3.40 per 1000 cubic feet		$ -
	Tires	$ per ton		$ -
Utilities subtotal				$ -
Labor	Operating labor	12.47 per hour		$ 30,400.00
	Supervising labor	15% of operating labor		$ 4,560.00
Maintenance Labor	Maintenance labor	19.18 per hour	1095	$ 21,002.10
	Maintenance materials	100% of maintenance labor		$ 21,002.10
Labor subtotal				*$ 76,964.20*
Disposal Revenue				*$ (510,000.00)*
Fuel Credit				*$ (500,000.00)*
Total annual direct cost				**$ (933,035.80)**
Total from capital cost worksheet				**$ 3,227,619.18**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 46,178.52
	Property tax	1% of total capital cost		$ 32,276.19
	Insurance	1% of total capital cost		$ 32,276.19
	Admin. Charges	2% of total capital cost		$ 64,552.38
Total annual indirect costs				$ 175,283.29
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF x total capital		$ 370,207.92
Total annual cost, TAC=DC+IC+capital recovery				$ (387,544.59)

Cost-Effectiveness ($ per ton NOx reduced)	High	$	(3,685)
	Low	$	(1,749)
Cost Per Ton of Clinker		$	(1.03)

ANNUAL COST WORKSHEET

Plant: TXI OPERATIONS, L.P
Kiln: MID-KILN FIRING, KILN 4

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton		$ -
	Electricity	$0.056 per kw-hr		$ -
	Nat. gas	$3.40 per 1000 cubic feet		$ -
	Tires	$___ per ton		$ -
Utilities subtotal				$ -
Labor	Operating labor	12.47 per hour		$ 30,400.00
	Supervising labor	15% of operating labor		$ 4,560.00
Maintenance Labor	Maintenance labor	19.18 per hour	1095	$ 21,002.10
	Maintenance materials	100% of maintenance labor		$ 21,002.10
Labor subtotal				*$ 76,964.20*
Disposal Revenue				*$ (510,000.00)*
Fuel Credit				*$ (500,000.00)*
Total annual direct cost				**$ (933,035.80)**
Total from capital cost worksheet				**$ 3,227,619.18**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 46,178.52
	Property tax	1% of total capital cost		$ 32,276.19
	Insurance	1% of total capital cost		$ 32,276.19
	Admin. Charges	2% of total capital cost		$ 64,552.38
Total annual indirect costs				$ 175,283.29
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF x total capital		$ 370,207.92
Total annual cost, TAC=DC+IC+capital recovery				$ (387,544.59)

Cost-Effectiveness ($ per ton NOx reduced)	High	$	(1,400)
	Low	$	(665)
Cost Per Ton of Clinker		$	(1.03)

CALCULATION SHEET FOR CAPITAL COST

Plant: TXI Operations
Kiln: Biosolids Injection, Kiln 5

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 240,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 108,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 79,200.00
Contingencies		Default is 20% of PEC	$ 48,000.00
Sales tax		3% PEC	$ 7,200.00
Freight		5% PEC	$ 12,000.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 751,321.28
	Capital cost		$ 1,245,721.28
	Annual cost assuming 15 year equipment life		**$ 83,048.09**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, LP
Kiln: Biosolids Injection, Kiln 1

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 240,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 108,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 79,200.00
Contingencies		Default is 20% of PEC	$ 48,000.00
Sales tax		3% PEC	$ 7,200.00
Freight		5% PEC	$ 12,000.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 493,156.10
	Capital cost		$ 987,556.10
	Annual cost assuming 15 year equipment life		**$ 65,837.07**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, LP
Kiln: Biosolids Injection, Kiln 2

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 240,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 108,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 79,200.00
Contingencies		Default is 20% of PEC	$ 48,000.00
Sales tax		3% PEC	$ 7,200.00
Freight		5% PEC	$ 12,000.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 452,992.05
	Capital cost		$ 947,392.05
	Annual cost assuming 15 year equipment life		**$ 63,159.47**

Note: PEC Costs based on 1997 Cost Analysis from NOx Control Technologies for Cement Industry, Final Report, EC/R, September 19, 2000

ANNUAL COST WORKSHEET

Plant: TXI Operations, L.P
Kiln: SNCR Kiln 5

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities*	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr	729033	$ 40,825.87
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$ per ton	0	$ -
Utilities subtotal				*$ 40,825.87*
Labor	Operating labor	12.47 per hour	10200	$ 127,194.00
	Supervising labor	15% of operating labor	2040	$ 19,079.10
Maintenance Labor	Maintenance labor	19.18 per hour	0	$ -
	Maintenance materials	100% of maintenance labor	Reagents (3483 t/yr)	$ 835,856.00
Labor subtotal				*$ 982,129.10*
Total annual direct cost				**$ 1,022,954.97**
Total from capital cost worksheet				**$ 3,948,966.28**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 589,277.46
	Property tax	1% of total capital cost		$ 39,489.66
	Insurance	1% of total capital cost		$ 39,489.66
	Admin. Charges	2% of total capital cost		$ 78,979.33
Total annual indirect costs				$ 747,236.11
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 452,946.43
Total annual cost, TAC=DC+IC+capital recovery				$ 2,223,137.52

Cost-Effectiveness ($ per ton NOx reduced)	High	$ 12,196.95
	Low	$ 2,439.39
Cost Per Ton of Clinker		$ 1.25

ANNUAL COST WORKSHEET

Plant: Holcim Texas, L.P
Kiln: SNCR Kiln 1

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr	729033	$ 40,826
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$ per ton	0	$ -
Utilities subtotal				*$ 40,826*
Labor	Operating labor	12.47 per hour	10200	$ 127,194
	Supervising labor	15% of operating labor	2040	$ 19,079
Maintenance Labor	Maintenance labor	19.18 per hour	0	$ -
	Maintenance materials	100% of maintenance labor	Reagents (3483 t/yr)	$ 835,856
Labor subtotal				*$ 982,129*
Total annual direct cost				**$ 1,022,955**
Total from capital cost worksheet				**$ 3,690,801**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 589,277
	Property tax	1% of total capital cost		$ 36,908
	Insurance	1% of total capital cost		$ 36,908
	Admin. Charges	2% of total capital cost		$ 73,816
Total annual indirect costs				$ 736,910
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equip-ment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 423,335
Total annual cost, TAC=DC+IC+capital recovery				$ 2,183,199

Cost-Effectiveness ($ per ton NOx reduced)	High	$ 11,432
	Low	$ 2,286
Cost Per Ton of Clinker		$ 1.87

ANNUAL COST WORKSHEET

Plant: Holcim Texas, L.P
Kiln: SNCR Kiln 2

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr	729033	$ 40,826
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$__ per ton	0	$ -
Utilities subtotal				*$ 40,826*
Labor	Operating labor	12.47 per hour	10200	$ 127,194
	Supervising labor	15% of operating labor	2040	$ 19,079
Maintenance Labor	Maintenance labor	19.18 per hour	0	$ -
	Maintenance materials	100% of maintenance labor	Reagents (3483 t/yr)	$ 835,856
Labor subtotal				*$ 982,129*
Total annual direct cost				**$ 1,022,955**
Total from capital cost worksheet				**$ 3,650,637**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 589,277
	Property tax	1% of total capital cost		$ 36,506
	Insurance	1% of total capital cost		$ 36,506
	Admin. Charges	2% of total capital cost		$ 73,013
Total annual indirect costs				$ 735,303
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 418,728
Total annual cost, TAC=DC+IC+capital recovery				$ 2,176,986

Cost-Effectiveness ($ per ton NOx reduced)	High	$	9,611
	Low	$	1,922
Cost Per Ton of Clinker		$	2.03

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, L.P.
Kiln: SNCR Kiln 5

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 1,201,496.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 599,558.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 732,794.00
Contingencies		Default is 20% of PEC	$ 532,941.00
Sales tax		3% PEC	$ 35,688.00
Freight		5% PEC	$ 95,168.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 751,321.28
	Capital cost		$ 3,948,966.28
	Annual cost assuming 15 year equipment life		

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, L.P
Kiln: SNCR Kiln 1

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 1,201,496.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 599,558.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 732,794.00
Contingencies		Default is 20% of PEC	$ 532,941.00
Sales tax		3% PEC	$ 35,688.00
Freight		5% PEC	$ 95,168.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 493,156.10
	Capital cost		$ 3,690,801.10
	Annual cost assuming 15 year equipment life		

Notes: Capital Cost from 2001 Submittal from Holcim to TCEQ

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, L.P.
Kiln: SNCR Kiln 2

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 1,201,496.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 599,558.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 732,794.00
Contingencies		Default is 20% of PEC	$ 532,941.00
Sales tax		3% PEC	$ 35,688.00
Freight		5% PEC	$ 95,168.00
Production downtime: assume 2 days lost production and a value of $77 per ton of product		Production per day	$ 452,992.05
	Capital cost		$ 3,650,637.05
	Annual cost assuming 15 year equipment life		

ANNUAL COST WORKSHEET

Plant: TXI Operations, L.P
Kiln: SCR Kiln 5

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$
	Electricity	$0.056 per kw-hr		$
	Nat. gas	$3.40 per 1000 cubic feet	0	$
	Tires	$ per ton	0	$
Utilities subtotal[1]				$1,400,000
Labor	Operating labor	12.47 per hour	10200	$127,194
	Supervising labor	15% of operating labor		$19,079
Maintenance Labor	Maintenance labor	10 % of PEC		$0
	Maintenance materials	100% of maintenance labor	Reagents and Catalysts	$1,479,000
Labor subtotal				$1,625,273
Total annual direct cost				**$3,025,273**
Total from capital cost worksheet				**$ 29,773,249**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 975,164
	Property tax	1% of total capital cost		$ 297,732
	Insurance	1% of total capital cost		$ 297,732
	Admin. Charges	2% of total capital cost		$ 595,465
Total annual indirect costs				$ 2,166,094
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equip-ment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 3,414,992
Total annual cost, TAC=DC+IC+capital recovery				$ 8,606,359

[1] Energy and fuel cost in 1992 Dollars from Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing, EPA, March 1994.

Cost-Effectiveness ($ per ton NOx reduced)	High $	5,902
	Low $	4,970
Cost Per Ton of Clinker	$	4.83

ANNUAL COST WORKSHEET

Plant: Holcim Texas, L.P
Kiln: SCR Kiln 1

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr		$ -
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$ ___ per ton	0	$ -
Utilities subtotal[1]				$ 1,400,000.00
Labor	Operating labor	12.47 per hour	10200	$ 127,194.00
	Supervising labor	15% of operating labor		$ 19,079.10
Maintenance Labor	Maintenance labor	10 % of PEC		$ 1,190,000.00
	Maintenance materials	100% of maintenance labor	Reagents and Catalysts	$ 1,479,000.00
Labor subtotal				*$ 2,815,273.10*
Total annual direct cost				**$ 4,215,273.10**
Total from capital cost worksheet				**$ 27,966,092.69**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 1,689,163.86
	Property tax	1% of total capital cost		$ 279,660.93
	Insurance	1% of total capital cost		$ 279,660.93
	Admin. Charges	2% of total capital cost		$ 559,321.85
Total annual indirect costs				$ 2,807,807.57
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equip-ment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 3,207,710.83
Total annual cost, TAC=DC+IC+capital recovery				$ 10,230,791.50

[1] Energy and fuel cost in 1992 Dollars from Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing, EPA, March 1994.

Cost-Effectivenes ($ per ton NOx reduced)	High $	6,696.60
	Low $	5,639.24
Cost Per Ton of Clinker	$	8.75

ANNUAL COST WORKSHEET

Plant: Holcim Texas, L.P
Kiln: SCR Kiln 2

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr		
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$ per ton	0	$ -
Utilities subtotal[1]				$ 1,400,000
Labor	Operating labor	12.47 per hour	10200	$ 127,194
	supervising labor	15% of operating labor	2040	$ 19,079
Maintenance Labor	Maintenance labor	19.18 per hour	0	$ -
	Maintenance materials	100% of maintenance labor	Reagents and Catalysts	$ 1,479,000
Labor subtotal				*$ 1,625,273*
Total annual direct cost				**$ 3,025,273**
Total from capital cost worksheet				**$ 27,684,944**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 975,164
	Property tax	1% of total capital cost		$ 276,849
	Insurance	1% of total capital cost		$ 276,849
	Admin. Charges	2% of total capital cost		$ 553,699
Total annual indirect costs				$ 2,082,562
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 3,175,463
Total annual cost, TAC=DC+IC+capital recovery				$ 8,283,298

[1] Energy and fuel cost in 1992 Dollars from Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing, EPA, March 1994.

Cost-Effectivenes ($ per ton NOx reduced)	High $	4,571
	Low $	3,849
Cost Per Ton of Clinker	$	7.72

CALCULATION SHEET FOR CAPITAL COST

Plant: TXI Operations, L.P.
Kiln: SCR Kiln 5

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 11,900,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 5,355,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 3,927,000.00
Contingencies		Default is 20% of PEC	$ 2,380,000.00
Sales tax		3% PEC	$ 357,000.00
freight		5% PEC	$ 595,000.00
Production downtime: assume 14 days lost production and a value of $77 per ton of product		production per day	$ 5,259,248.94
	Capital cost		$ 29,773,248.94
	Annual cost assuming 15 year equipment life		

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, L.P.
Kiln: SCR Kiln 1

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 11,900,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 5,355,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 3,927,000.00
Contingencies		Default is 20% of PEC	$ 2,380,000.00
Sales tax		3% PEC	$ 357,000.00
Freight		5% PEC	$ 595,000.00
Production downtime: assume14 days lost production and a value of $77 per ton of product		Production per day	$ 3,452,092.69
	Capital cost		$ 27,966,092.69
	Annual cost assuming 15 year equipment life		

Notes: REC Cost in 1992 Dollars from Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing, EPA, March 1994.

CALCULATION SHEET FOR CAPITAL COST

Plant: Holcim Texas, L.P.
Kiln: SCR Kiln 2

Purchased equipment cost, Includes the control device, auxiliary equipment and instrumentation.)			$ 11,900,000.00
Direct installation costs (includes physical items needed to install new equipment such as foundations and supports, equipment handling, electrical, piping, ductwork and painting)		Default is 45% of PEC	$ 5,355,000.00
Indirect installation costs (includes engineering, construction & field expenses, contractor fees, start-up, and performance testing)		Default is 33% of PEC	$ 3,927,000.00
Contingencies		Default is 20% of PEC	$ 2,380,000.00
Sales tax		3% PEC	$ 357,000.00
Freight		5% PEC	$ 595,000.00
Production downtime: assume 14 days lost production and a value of $77 per ton of product		Production per day	$ 3,170,944.38
	Capital cost		$ 27,684,944.38
	Annual cost assuming 15 year equipment life		

Notes: REC Cost in 1992 Dollars from Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing, EPA, March 1994.

ANNUAL COST WORKSHEET

Plant: Holcim Texas, L.P
Kiln: MSC-SNCR Kiln 1

Annual direct cost calculations		Multiplier	Change	Calculation
Utilities	Coal	23.47 per short ton	0	$ -
	Electricity	$0.056 per kw-hr	729033	$ 40,826
	Nat. gas	$3.40 per 1000 cubic feet	0	$ -
	Tires	$ per ton	0	$ -
Utilities subtotal				*$ 40,826*
Labor	Operating labor	12.47 per hour	10200	$ 127,194
	Supervising labor	15% of operating labor	2040	$ 19,079
Maintenance Labor	Maintenance labor	19.18 per hour	0	$ -
	Maintenance materials	100% of maintenance labor	Reagents (3483 t/yr)	$ 835,856
Labor subtotal				*$ 982,129*
Total annual direct cost				**$ 511,477**
Total from capital cost worksheet				**$ 3,690,801**
Annual indirect cost calculation				
	Overhead	60% of all labor categories and materials		$ 589,277
	Property tax	1% of total capital cost		$ 36,908
	Insurance	1% of total capital cost		$ 36,908
	Admin. Charges	2% of total capital cost		$ 73,816
Total annual indirect costs				$ 736,910
Capital recovery calculation				
	Capital recovery factor (CRF)	Assume 7.7% interest rate and a 15-year equipment life.		0.1147
	Annual capital cost	CRF = 0.1147 per dollar		$ 423,335
Total annual cost, TAC=DC+IC+capital recovery				$ 1,671,722

Cost-Effectiveness ($ per ton NOx reduced)	High	$ 8,754
	Low	$ 1,751
Cost Per Ton of Clinker		$ 1.43

APPENDIX G

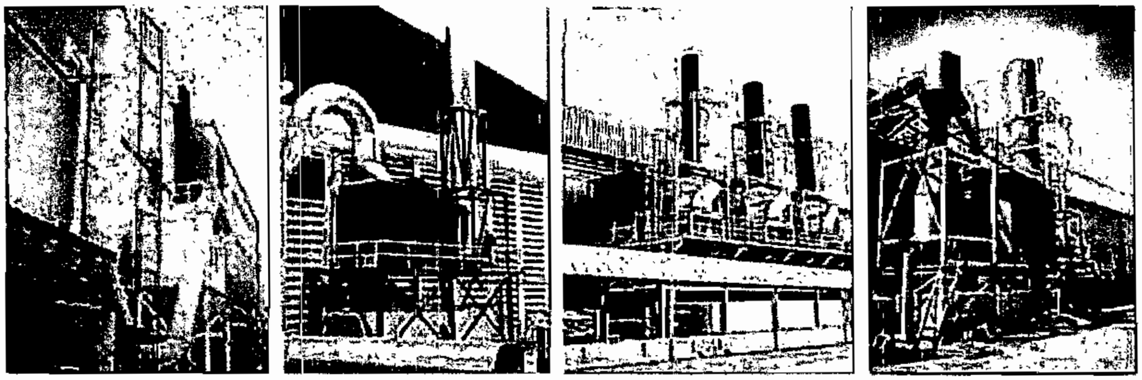
Appendix G

Section 4 of the

Assessment of Control Technology Options for BART-Eligible Sources, Northeast States for Coordinated Air Use Management In Partnership with The Mid-Atlantic/Northeast Visibility Union

Assessment of Control Technology Options for BART-Eligible Sources

Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities



Prepared by
Northeast States for Coordinated Air Use Management
In Partnership with
The Mid-Atlantic/Northeast Visibility Union

March 2005

4. PORTLAND CEMENT KILNS

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 2,650°F. High combustion temperatures require significant amounts of fuel and can result in significant emissions of NO_X and SO_2. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

The cement industry has seen significant growth in capacity and technology over the last 30 years. In 2000, the U.S. had 201 cement kilns with the annual capacity to produce 84 million metrics tons of concrete, with production projected to grow to 109 million metric tons in 2004 (Portland Cement Association, 2000).

4.1. Description of Cement-Making Processes

Concrete is a combination of Portland cement, sand, and gravel. The key component of Portland cement is clinker, a material produced by heating limestone and other raw materials to temperatures over 2,650°F, requiring combustion temperatures of about 3,000°F. These high temperatures are normally achieved in a rotary kiln, as shown in Figure IV-1. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

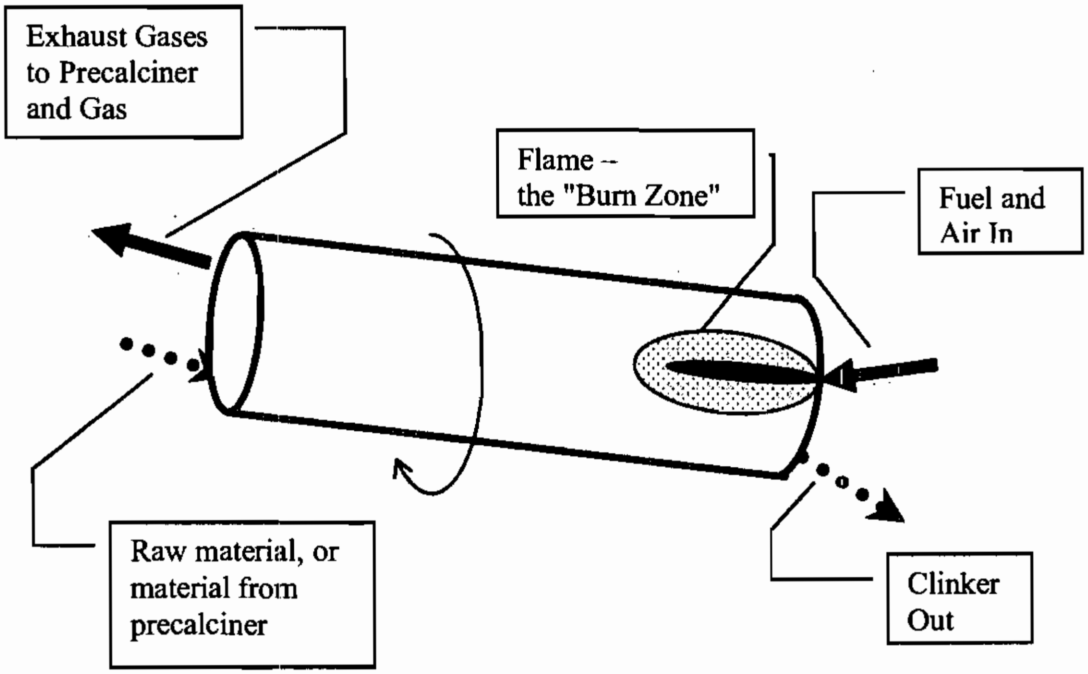


Figure IV-1. Simplified Sketch of a Rotary Kiln.

Cement kilns fall into four general process categories. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500°F to 1,650°F. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. In long kiln systems, the raw feed material is added to the rotary kiln itself as either a powder ("dry") or a slurry ("wet"). Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and typically have greater capacity. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Preheaters could also be replaced with suspension preheaters, but these are less common. If past trends continue, many of the existing long wet kilns and dry kilns are expected to be replaced with precalciner and preheater kilns since precalciner and preheater kilns are more energy efficient and also typically have greater capacity.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. The current fuel use in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NO_X for nearly all cement applications (see the section on NO_X controls included later).

Recent years have seen Portland cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility's outputs or reduce their operating costs. Incidentally, some of these technologies also offer the potential to reduce NO_X and other emissions.

4.2. Review of BART-Eligible Cement Kilns in the MANE-VU Region

NESCAUM's analysis of BART-eligible sources in the MANE-VU Region[6] (NESCAUM, 2004) identified two Portland cement facilities as being eligible for BART. The facilities are shown in Table IV-1. *[Editor's note: Additional facilities are likely to be added when PA and NY inventories are complete]*

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[6] NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

Table IV-1 BART-Eligible Portland Cement facilities in MANE-VU Region

Facility	Kiln type	Capacity, thousands tons/yr	Primary Fuel(s)
St. Lawrence Cement (Hagerstown, MD)	Dry	550	Coal
Dragon Products (Thomaston, ME)	Wet	392	Coal, petcoke

4.3. Available Control Technologies

A number of technologies exist for controlling emissions from cement kilns. Secondary (post-combustion) control devices can be helpful in reducing emissions, and a variety of these are available. Many technologies and techniques have been developed in response to a specific environmental need and target a specific pollutant, sometimes achieving reduction in other pollutants at the same time. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the targeted pollutant. Controls are examined for SO_2, NO_X, PM, and VOCs.

4.3.1. SO_2 Controls

In contrast with electric utility boilers, SO_2 emissions from rotary kilns producing cement clinker under oxidizing conditions are nearly independent of fuel sulfur input, but, rather, are closely related to the amount of sulfide (e.g. pyrite) in kiln feed and to the molar ratio of total sulfur to total alkali input to the system. In cement kilns SO_2 emissions generally depend on:

- Inherent SO_2 removal efficiency of kiln system,
- Form of sulfur (e.g. pyritic) and sulfur concentrations in raw material,
- Molecular ratio between sulfur and alkalis,
- Prevailing conditions (oxidizing or reducing) and their location within kiln, and
- Temperature profile in the kiln system.

Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit of reducing SO_2 levels.

In addition to the control techniques used in the electric utility boilers, cement plants may also resort to other basic reductions techniques involving reduction of sulfur input to the kiln, by switching fuels or changing the limestone, or reduction of SO_2 emissions from reducing both the sulfur in the sources and using a secondary control device. It is common to achieve some level of SO_2 reductions when seeking to reduce another pollutant, usually NO_X (technologies targeting another pollutant, but also reducing SO_2, are described in the NO_X and PM sections below). In addition to considering a change in the primary fuel for the kiln, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO_2. Including high-pressure air injection at a mid-kiln firing site can limit oxygen in the kiln and suppress SO_2 formation (Hansen, 2002). Since these techniques are primarily used to reduce NO_X, more information about mid-kiln fuel injection can be found in the section on NO_X emissions, but other specific SO_2 control technologies applicable to cement kilns are listed below.

Fuel Switching

Selecting a fuel with lower sulfur content, a strategy commonly adopted in the utility boilers, is less effective in cement-making systems, where SO_2 emissions are not strongly dependent on fuel sulfur content. Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO_2 emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit in SO_2 levels.

Inherent Removal

Raw materials, primarily limestone, are preheated in the cement-making process either in the preheater tower or in the rotary kiln. In either case, the limestone comes in contact with hot combustion exhaust gases. The calcium in the lime reacts with SO_2 in the gas, providing in-process removal of sulfur in the kiln system. Removal efficiencies in rotary kiln systems range between 38% and 99% of sulfur input, and 50% to 70% of the remaining SO_2 is removed from exhaust gases when passing through an in-line raw mill system (Miller et al., 2001).

Process Alterations

The following methods to remove and prevent formation of SO_2 by modifying or controlling conditions in the system are available due to the nature of the Portland cement manufacturing process:

- The oxygen concentration of the exhaust gases can be controlled to ensure sufficient oxygen exists to stabilize alkali and calcium sulfate compounds formed in the process. Concentrations of O_2 and, more importantly CO, have a strong influence on the stability of alkali and calcium sulfates in the burning zone. Control of burning- zone O_2 and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary kilns producing cement clinker. The downside of this technique is the more favorable conditions created for generation of NO_X in the rotary kiln.
- Burning-zone flame shape can be modified to minimize localized reducing conditions. It has been observed (Hansen, 1986) that flame impingement in the hot zone had a major effect on SO_2 emissions from the kiln, even if total oxygen is sufficient to fully combust all fuel. Avoiding flame impingement in the burning zone minimizes SO_2 formation. Avoiding flame impingement on the clinker, a technique applicable to all rotary

kilns producing cement clinker, requires proper solid fuel preparation and proper flame shaping and control.

- Raw materials can be altered to affect the alkali/sulfur molar ratio. SO_2 concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur; when alkalis are in excess of sulfur, SO_2 emissions are typically low, due to more sulfur being retained in clinker as alkali sulfates. Also, kiln feed containing carbon seems to directly cause SO_2 emissions. Changing raw materials may reduce SO_2 emissions. Substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds reduces SO_2 emissions. Replacement of raw materials, however, is often constrained by economic considerations, while alkali input increase may also be limited by cement product quality specifications on total alkali in cement.
- Alterations to system can influence SO_2 emissions. It has been found that an improved distribution of kiln feed may equalize temperatures in bottom stage cyclones and reduce SO_2 emission by as much as 20% (Miller, 2001).

Scrubbers

Dry Reagent Injection

Steuch and Johansen (1991) found that $Ca(OH)_2$ (hydrated lime) was the most effective scrubbing agent, particularly when added to the kiln feed and when the exhaust gases were near the dew point. Adding quicklime or hydrated lime into the upper preheater cyclones demonstrated up to 70% removal efficiency (Nielse, 1991).

Several dry reagent systems are available:

- The RMC Pacific process (Sheth, 1991) injects dry $Ca(OH)_2$, and with different stoichiometric ratios (40:1 to 50:1), has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.
- Krupp Polysius Polydesox process uses hydrated lime where SO_2 in the raw feed tends to form from pyrites and obtains removal efficiencies of up to 85% (Miller, 2001).
- De-SoX Cyclone, by Fuller Company (Miller, 2001), reduces SO_2 emissions in a precalciner kiln by removing a portion of the gases from the precalciner outlet to a cyclone, and from there to the Stage II cyclone where pyritic sulfur in kiln feed is decomposed into SO_2. The feed (or "raw meal"), containing freshly produced lime, is discharged into the outlet duct of the second stage (this process is known as hot meal injection)._Removal efficiencies of 5 to 30% are claimed.

Lime/Limestone Spray Dryer Absorber

Design stoichiometric ratios of calcium to sulfur for spray dryer systems in utility boilers are typically between 0.9 and 1.5, with most below 1.0. These SO_2 scrubbers are designed for removal efficiencies in excess of 80%.

SO_2 reacts with $CaCO_3$, to form $CaSO_4$, a reaction that becomes more complete as the temperature and the fineness of $CaCO_3$ increase. The presence of water vapor also increases conversion.

Most of the spray dryer type SO_2 control technologies in the cement industry are applied to preheater or preheater/precalciner kilns. Exhaust gases from long dry kilns are cooled by either spray water introduced into the feed end of the kiln or by dilution air-cooling after the gases leave the kiln. Adding a conditioning tower to replace water sprays or dilution air enables the alkaline slurry system to be used to reduce SO_2 emissions (the equivalent of a spray dryer). The range of temperatures for exit gases from long wet kilns does not allow the use of an alkaline slurry spray dryer type scrubber because the addition of the lime slurry may drop the exhaust gases temperature below the acid dew point, creating significant plugging and corrosion problems in the downstream Particulate Control Device (PCD), duct work, and induced draft (ID) fan.

RMC Pacific's Alkaline Slurry Injection System (Sheth, 1991)

RMC Pacific uses a hydrated lime, spray dryer absorber to reduce SO_2 emissions. The captured sulfur compounds are returned as a portion of the raw material feedstock to the roller mill, which results in no scrubber effluent or sludge disposal. When SO_2 emissions are high and preheater exit gas temperatures are low, sufficient lime slurry cannot be added to reduce SO_2 to acceptable levels. With different stoichiometric ratios (40:1 to 50:1), the process has obtained efficiencies ranging from 55% to 65%. SO_2 removal of 80% was obtained with injection into the roller mill.

EnviroCare Microfine Lime System (Miller, 2001)

This system uses the existing gas conditioning tower to introduce the scrubbing reagent (water suspension of finely pulverized calcium hydroxide, $Ca(OH)_2$). The small size of the lime particles (3-10 microns) allows the particles to dissolve in water droplets quickly and react with SO_2 as it is absorbed into the water droplet. The dried lime continues to react with any remaining SO_2 in the downstream kiln system and PCD. Lime injection rate can be optimized through a feedback control loop from an SO_2 monitor. EnviroCare claims an SO_2 removal efficiency of greater than 90%.

Wet SO_2 Scrubbers

Wet scrubbers have been used successfully in the utility industry. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control applied to the exhaust gas from a cement kiln can be avoided if these systems are installed downstream of a high efficiency PCD (e.g., fabric filter). Failure of the PCD can pose difficult problems for a downstream wet scrubber.

Fuller Company (FLS Miljø) (Miller, 2001)

The Monsanto Dyna Wave wet SO_2 scrubber has been installed by the Fuller Company and used on several cement kilns in the U.S. This wet scrubber is designed to remove SO_2, halide gases, and some particulate matter.

The scrubber, typically located downstream from the kiln PCD and operated under positive pressure, uses limestone as the absorbent. A slurry (approximately 20% limestone and 80% water) produced in the mixing tank is sprayed countercurrent to the gas flow to cool the gases and react with SO_2 forming calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$), which precipitates. Air is sparged into the sump at the bottom of the tower to oxidize $CaSO_3$ to $CaSO_4+2H_2O$ (gypsum).

Monsanto EnviroChem DynaWave (Miller, 2001)

DynaWave is a "Reverse Jet" scrubber that can simultaneously accomplish several gas cleaning/process needs: hot gas quenching, particulate removal, and acid gas absorption. The reverse jet is an annular orifice scrubber having one to three large-bore nozzles through which a relatively large volume of scrubbing liquid is injected counter to the gas flow to create a froth zone. The gas collides with the liquid, forcing the liquid radialy outward toward the wall. A standing wave, created at the point the liquid is reversed by the gas, is an extremely turbulent region where the gas absorption and particulate collection occurs.

The system is a tailpipe system generally installed downstream of the PCD, and operates with a saturated gas stream. Therefore, it would likely be applicable to most if not all the cement kilns. A single-stage DynaWave scrubber in full-scale operation has a reported SO_2 removal efficiency of about 90%. Monsanto EnviroChem claims that multiple units may be installed in series to achieve whatever removal efficiency is required (e.g., 99.9%).

4.3.2. NO_X Controls

The following sections discuss the formation of NO_X in cement kilns, potential NO_X control techniques, NO_X control in the cement industry, and the cost effectiveness of applicable controls.

NO_X Formation in Kiln Systems

Nitrogen oxides (NO_X) are formed during the combustion of fuels in the cement-making process. In kiln exhaust gases, more than 90% of NO_X is NO, with NO_2 generally making up the remainder from rotary kilns producing cement clinkers (Gardeik, 1984). There are three different NO_X formation mechanisms - thermal, fuel, and feed NO_X - typically contributing to NO_X emissions.

Thermal NO_X

Thermal NO_X is formed by oxidation of atmospheric molecular nitrogen at high temperatures (>1,200 °C). Most NO_X formed in the high-temperature environment of the main combustion zone (burning zone) of a kiln is "thermal NO_X". Since the flame temperature in a kiln is significantly above that threshold, a considerable amount of thermal NO is generated in the burning zone.

While conditions in the burning zone of a cement kiln favor formation of thermal NO_X, those prevalent in secondary combustion zones (e.g. calciners, preheater riser ducts and mid-kiln firing in long wet or dry kilns) with temperatures below 1200°C, are less conducive to significant thermal NO_X formation. In that zone, formation of fuel NO_X and feed NOx is more prevalent.

The amount of thermal NO_X produced is related to fuel type, burning zone temperature, and oxygen content. Therefore, raw materials that are hard to burn (i.e., materials that require more heat input per ton of clinker produced) generate more NO_X.

Fuel NO_X

Fuel NO_X is the result of oxidation of nitrogen compounds in fuel. Fuel nitrogen is only partially converted into NO_X during combustion. The amount formed depends on fuel type, precalciner type and precalciner temperature. NO_X formed in the secondary combustion zone, primarily fuel NO_X (Gardeik, 1984), depends on:

- Nitrogen concentration in the fuel,
- Oxygen concentration in the combustion zone,
- Initial NO concentration in the combustion gas,
- Volatile concentration in the (solid) fuel, and
- Temperature in the secondary combustion zone.

As opposed to the burning zone of the kiln, where higher temperatures result in much higher NO_X formation, higher temperatures (up to 1100°C) in the precalciner may actually reduce NO_X emissions when a fuel containing nitrogen is used (Nielsen, 1990).

In the design of modern low-NO_X calciners, high temperatures and reducing conditions are proven methods for suppressing the formation of fuel NO_X generated in the precalciner, and for destroying thermal NO_X generated in the burning zone of the rotary kiln (Keefe and Shenk, 2002).

Feed NO_X

NO_X emissions can also result from the oxidation of nitrogen compounds in the raw material feed to the kiln (feed NO_X). The range of nitrogen concentrations in various kiln feeds is 20-1000 ppm (Gartner, 1983) and the potential contribution of feed NO_X to total NO_X emissions is 0.2-10 lbs of NO_X per ton of clinker.

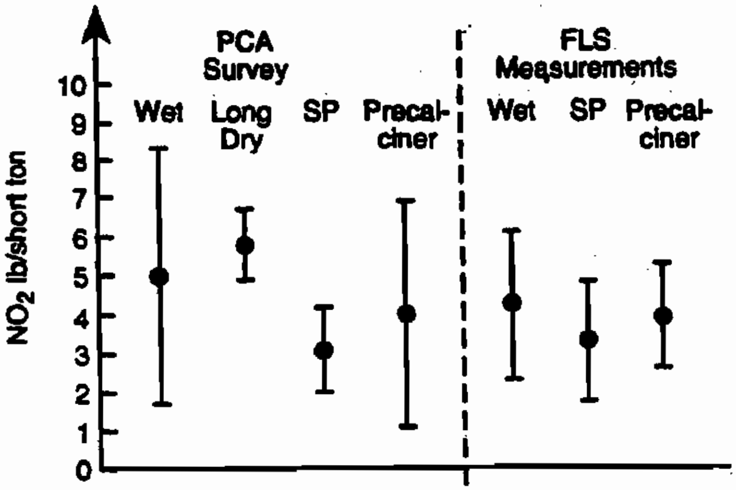
Up to 50% of feed nitrogen may be converted to NO_X, if raw materials are heated slowly: with rapid heating, the conversion rate is much lower.

The following conclusions can be made for rotary kiln systems (Young and von Seebach, 1999):

- Formation of thermal NO_X in the burning zone is the major contributor to NO_X emissions from the kiln
- Fuel NO_X is the major contributor in the secondary combustion zone of precalciner and riser duct fired preheater kilns
- Feed NO_X is usually a minor contributor to the total NO_X generated in rotary kiln systems.

It should be further noted that, due to the dynamic nature of kiln operations, NO_X formation can be highly variable so each kiln will tend to have unique NO_X emission characteristics, inherent to the variability in cement manufacturing process. Figure IV-2 illustrates the wide range of NO_X emissions from different types of kilns.

NO_X emissions rates are also site- and kiln-specific, and may be quite dissimilar between two apparently identical kilns, for causes not fully understood, but, probably connected to the raw materials used. Other causes for NO_X emissions rate differences may result from different types or classes of cement products being produced; chemical variations between these different products can influence cement kiln operating parameters and thus NO_X emissions. Short-term process transients such as kiln feed rates and fuel quality also affect NO_X emissions. All of these factors can influence the applicability and costs of incorporating NO_X controls.



	PCA Survey				FLS Measurements		
	Wet	Long Dry	SP	Precal-ciner	Wet	SP	Precal-ciner
Number of Kilns	8	3	3	10	7	13	7
Average	4.97	5.70	2.98	3.86	4.07	3.13	3.77
Standard Deviation	3.28	0.85	1.05	2.89	1.89	1.57	1.31

Figure IV-2. NO_X emissions for various cement kiln types (USEPA, 1994).
(SP: Suspension Preheater kilns)

NO_X Control Techniques

There are two broad categories of NO_X reduction techniques for cement kilns: 1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_X in the manufacturing process (modifications for cement kilns include low-NO_X Burners (LNB), secondary combustion, and staged combustion); and 2) post-combustion (secondary) controls, where flue gases are treated to remove NO_X that has already been formed.

It should be noted that the quality of clinker produced in a kiln varies with characteristics of the combustion, so primary controls need to be selected carefully. Dry low-NO_X (DLN) operation, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NO_X. Low excess air and air-staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a LNB has been successfully used in some facilities, including California Portland Cement. Low-NO_X combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter).

The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NO_X.

LNBs can be used when indirect firing is employed. When implementing indirect firing with LNBs, other process improvements are often implemented, such as better process controls. According to Portland Cement Association (1998), 20%-30% NO_X reductions can be achieved from the use of indirect firing with LNBs and associated process modifications.

Combustion modifications are less successful at reducing NO_X emissions in thermal processing applications (like cement kilns) than in boilers for steam and/or power production. Chemical reactions producing cement clinker require high material and gas temperatures, and product quality also requires an oxidizing atmosphere in the combustion zone of a cement kiln. Excessively high temperatures in the burning zone pose equipment damage risk, while temperatures too low will no longer produce a salable product.

NO_X emissions can also be affected by kiln feed chemical characteristics, feed chemical uniformity, and specific fuel consumption. As stated by EPA's NO_X Alternative Control Technique Document for the Cement Manufacturing Industry (USEPA, 1994), "For any given type of kiln, the amount of NO_X formed is directly related to the amount of energy consumed in the cement-making process. Thus, measures that improve the energy efficiency of this process should reduce NO_X emissions in terms of lb of NO_X / ton of product."

Following are some of the more common process modifications that have been made to reduce NO_X emissions from cement kilns (NESCAUM, 2001):

- Changing fuel (e.g. natural gas to coal firing).
- Improving kiln feed chemical uniformity, for more stable kiln operations:
    - Modifications to quarry operations,
    - Raw material blending facilities, and
    - On-line analytical control systems for raw material proportioning (e.g. kiln feed blending systems).
- Modifications to improve thermal efficiency, including:
    - Reducing excess air infiltration,
    - Increasing efficiency of cyclones in preheater kilns,
    - Reducing the amount of moisture in slurry (wet process kilns only),
    - Revising kiln chain systems in long wet or long dry kilns,
    - Modifying or replacing clinker coolers to improve heat recovery and cooler efficiency,
    - Initiating operator training programs, and

    - o Returning as much cement kiln dust (CKD) as possible to the kiln system (without adversely affecting product quality).
- Installing or upgrading kiln system sensors and instrumentation.
- Installing or upgrading computer controls of kiln systems to stabilize kiln operation and avoid burning zone temperature variations.

According to Young and von Seebach (1999), industry data and experience show that control of burning zone temperature is the primary process control method applicable to lowering thermal NO_X formation. Process modifications that allow better control of the kiln burning zone temperature will result in reducing thermal NO_X formation and minimizing NO_X spikes. Stable kiln operation, through feed chemical uniformity, results in overall NO_X reductions of 10% - 15%, while poor kiln feed chemical uniformity results in overfiring the kiln, and higher NO_X emissions.

Fuel Switching

Switching to a lower-nitrogen fuel in a precalciner may reduce NO_X emissions, but the nitrogen content of the fuel burned in the burning zone has little or no effect on NO_X generation. Generally, no relationship has been found between fuel nitrogen content and the NO_X emissions from a cement kiln (Miller and Egelov, 1980).

Process Optimization and Automated Control

Process optimization is a common method for reducing NO_X emissions from cement kilns. In principle, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NO_X generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NO_X control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NO_X reductions reported in this Chapter are generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions reported in a case study (NESCAUM, 2001) equivalent to 55% reduction in average NO_X emissions - from 845 lb/hr to 383 lb/hr – were achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NO_X reduction for an overall NO_X emission reduction of 59% from controls.

Flue Gas Recirculation

Flue gas recirculation (FGR) or water/steam injection into the main flame to reduce flame temperatures and NO_X formation is not a viable method of reducing NO_X in a cement kiln burning zone. FGR's effectiveness relies on cooling the flame and generating an oxygen deficient (reducing) atmosphere for combustion to reduce NO_X formation, conditions that are not compatible with cement kiln operation. High flame temperature and an oxidizing atmosphere are process requirements to produce a quality clinker product.

Indirect Firing

Conversion from a direct coal firing system to an indirect firing system kiln with a low NO_X burner may result in NO_X reductions ranging from 0% to about 20% (Kupper et al., 1990; Schrsemli, 1990). Incorrect use of multi-channel (low NO_X) burners can increase NO_X rather than reduce NO_X, and it has been found (Hansen, 1985) that less excess air in the kiln combustion gases results in less NO formation at the same burning zone temperature. NO_X reductions of 15% were reported.

Low-NO_X Burners

LNBs have been successfully used in the primary burn zone and especially in the precalciner kilns.

Secondary combustion zones have proven effective at reducing NO_X emissions in cement kilns. In long kilns, secondary combustion can be partly accomplished by mid-kiln injection of fuel (less than 20% of kiln fuel). NO_X emissions are reduced because less fuel is burned in the high temperature environment of the burning zone. Another NO_X reducing technique is the use of fuel in the riser duct of preheater kilns, although, because of high prevailing temperatures, such reductions do not always occur. With precalciner kilns, which employ a secondary combustion zone at a much lower temperature than the burning zone, typically 60% of the fuel is burned in the precalciner, with the combustion air coming directly from the clinker cooler, and NO_X emissions for these kilns are less than from long wet, long dry, or preheater kiln systems because 60% of the total fuel requirement is burned under lower temperature conditions where negligible amounts of thermal NO_X are formed. Furthermore, precalciner kilns have the potential for staged combustion as a NO_X control technique. All major equipment suppliers offer "low-NO_X" precalciner designs. Fuel burned in a sub-stoichiometric O2 environment creates a strongly reducing atmosphere (relatively high concentrations of CO) that inhibits formation of fuel NO_X and destroys a portion of the NO_X formed in the kiln burning zone. Additional tertiary combustion air is added later to complete combustion of the fuel.

Staged combustion has become a well-known method for reducing NO_X emissions from cement plants, but as NO_X and CO emissions limits become more stringent, control via fuel and air staging are coming under reconsideration. Low- NO_X calciners combine high temperature combustion and firing under reducing conditions without staging fuel/air.

Low-NO_X Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner can be low enough to reduce thermal NO_X but still be effective in heating the limestone.

Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NO_X reductions can be substantial. All new precalciner kilns are equipped with low-NO_X burners in the precalciner. Low-NO_X precalciners have been shown to reduce NO_X by 30%-40% compared to conventional precalciners (Young and von Seebach, 1998). This reduction is from the precalciner-generated NO_X, not for the entire kiln.

Several precalciner kilns in the U.S. have recently been retrofitted with these "two-NO_X" calciners, and several new kiln lines have been installed using low-NO_X precalciner technology. Operating experience indicates a noticeable reduction in NO_X per ton of clinker. Industry reports place the NO_X reduction potential of staged combustion with a low-NO_X precalciner at 30% - 40% when compared to a conventional precalciner kiln system.

Low-NO_X precalciner is a proven way to reduce NO_X emissions in a cement-making system, and all new cement-making systems are expected to be built with it. They come in two types, "in-line", commonly used with "normal" fuels (e.g. coal, oil, gas), or "separate-line", selected for difficult-to-burn fuels (e.g. petroleum coke and anthracite) because its high oxygen atmosphere ensures improved fuel burnout. In-line calciners have lower specific NO_X emissions than separate-line ones, but both are capable of meeting current CO/NO_X emission standards for any combination of fuel and feed, and both are dependent on the presence of strong reduction and oxidation zones.

CemStar

Another approach that has been proven effective in reducing NO_X is the patented CemStar process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures (Young, 1995; Young, 1996). In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment.

The CemStar approach has many advantages: energy input can be reduced, NO_X emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NO_X generation. NO_X reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NO_X is high due to thermal NO_X, CemStar is likely to provide reductions on the order of 40%-50%. Results of controlled testing of CemStar with baseline conditions resulted in 20% reduction in NO_X, corresponding with a reduction in average burn-zone temperature of over 200°F. Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

TXI, the developer of CemStar, reports that more than 10 plants are currently equipped with the technology. NESCAUM (2001) discusses one application of CemStar on a long-wet process kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NO_X by about 30% with mid-kiln heat input comprising about 20% of the total heat input (Portland Cement Association, 1998). Results of tests of mid-kiln firing on several kilns are summarized in Table 2 (NESCAUM,2001). The average NO_X reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NO_X produced in the primary burn zone. Fuel NO_X will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar (Schrama et al., 1995; Stillwater and Wahlquist, 1998). Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.

Table IV-2 NO_X Reduction at Cement Kilns Using Mid-Kiln Technology (NESCAUM,2001)

Initial NO_X (ppm)	936	1372	1342	1359	565	513
Final NO_X (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

High-pressure air injection, mentioned in the previous section as a potential control for SO_2 emissions, was primarily developed as a NO_X reduction strategy (Hansen, 2002). The technique was designed for use with staged fuel combustion (mid-kiln firing) and mixing air. Mid-kiln firing with mixing air creates stratified thermal layers in the kiln, preventing immediate combustion of the mid-kiln fuel and lowering exit oxygen levels enough that additional CO is produced. Injecting high-pressure air into the kiln provides energy to mix the layers, lowering the main flame temperature and creating a reducing area between the fuel and air injection points, which encourages the destruction of NO_X. The technique has been shown to reduce NO_X by about 50%, while also reducing CO by 47% and SO_2 by 97%.

Biosolids Injection

Biosolids Injection (BSI) is a technology that was developed in the 1990's by the cement industry for NO_X reduction in precalciner and preheater kilns (Biggs, 1995). BSI adds dewatered sewage sludge to the mixing chamber of the precalciner. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NO_X. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NO_X from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NO_X reduction, but it will depend on the specifics of the kiln.

Selective Non-catalytic Reduction

Selective Non-catalytic Reduction (SNCR) of NO_X is based on the injection of a reagent, typically NH3 or urea, into the kiln system at a location with an appropriate temperature window 1140 – 2010oF (870 - 1100°C). Some researchers have found that the most effective temperature range is narrower, about 1650 – 2000°F (900 - 1000°C). Temperature is critical because no catalyst is used. At temperatures too high, the reagents will form additional NO_X, and, at low temperatures, the reactions proceed slowly and promote the escape of substantial amounts of unreacted ammonia. Under optimum conditions about one mole of NH3 is required to reduce one mole of NO_X, but the amount of NH3 is always critically dependent on the reaction temperature. Ammonia slip, which increases rapidly when the molar ratio of NH3 to NO is above one, causes a detached plume and can increase opacity of the stack gases.

Preheater and precalciner kilns operate with kiln gas exit temperatures in the appropriate temperature range. SNCR systems have been used on some preheater kilns in Europe. For wet and long dry kilns, these temperatures exist midway through the kiln. Access to this area is possible only through ports in the kiln shell as used in mid-kiln firing or with scoops used to return cement kiln dust. Ammonia must be added continuously in a fixed molar ratio to NO_X in order to be effective and to minimize ammonia slip. Therefore, SNCR is not technically feasible at this time on long wet process or long dry process kilns.

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries (Steuch et al., 1994; Sun et al., 1994). Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table 3 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good.

Although SNCR technology has the potential to offer significant reductions on some precalciner kilns and it is being used in numerous cement kilns in Europe, it has been tested in only one facility in the U.S.

Table IV-3 NO_X Reduction Performance of Urea SNCR on Precalciner Cement Kilns (NESCAUM, 2001)

Company / Location	Unit Type	Size (MMBtu/hr)	NO_X Baseline	Reduction (%)	NH_3 SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Precalciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Precalciner	260 697 658	1.29 lb/MMBtu 1.58 lb/MMBtu 0.92 lb/MMBtu	50 45 25	15 15 15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm^3 500 ppm	90	na

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) uses ammonia, in the presence of a catalyst (e.g. titanium dioxide; vanadium pentoxide), to selectively reduce NO_X emissions from exhaust gases. SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the U.S. Typically, anhydrous ammonia, usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NO_X is reduced to N_2 gas and water. The optimum temperature for SCR depends on the catalyst but is usually between 570 and 840°F (300 and 450°C).

Exit gas temperatures from dust collectors on wet kilns, for long dry kilns, and for dust collectors in preheater kilns that use in-line raw mills for grinding and drying raw materials are relatively low and flue gases would have to be reheated before employing SCR. This technology so far has not been applied to the cement kilns but is being evaluated by some of the state air permitting agencies as Best Available Control Technology (BACT) for some of the new cement kilns being proposed in the U.S.

Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, one of the case studies in *Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness* (NESCAUM, 2001) combines indirect firing and mid-kiln firing to reduce NO_X by a combined amount approaching 50%. It is also reasonable to expect that technologies such as CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits, and it may be feasible to use SNCR or SCR in combination with other controls for cement kilns. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NO_X reductions may not be additive.

4.3.3. $PM_{2.5}$ Controls

The particulate matter exiting the kiln system with the exhaust gases is relatively coarse, with most of the particuate matter having diameters greater than 10 microns, but the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading.

As is the case for many other industrial sectors, the main control options for fine particles are baghouses (more formally known as Fabric Filters) and electrostatic precipitators (ESPs), described in Section 2.3.2 (EGUs). The following section describes some issues specifically related to cement kilns and the use of these devices, including a new filter system combining a baghouse and an ESP.

Cement kilns primarily utilize baghouses of the reverse-air and pulse-jet types. Both types are usually configured so that the bags can be cleaned during an “off-line” cycle, in which a section of the baghouse is closed off from the main exhaust flow for cleaning. This tends to reduce the need for a high-pressure pulse that causes additional wear on the filtration fabric, allows less time for particles to be collected in the hopper during its brief and frequent use, and requires additional power for operation. The choice between a reverse-air and pulse-jet system is generally made on the basis of the volume of exhaust and production from the kiln. In general, kilns producing less than 1650 stpd (with exhaust volumes below 128,000 acfm) are most efficiently served by a jet-pulse system (D’Lima and Pirwitz, 2000). The decision is more complex for kilns up to 6600 stpd (with exhaust volumes up to 853,000 acfm), for which initial equipment costs are similar but lifetime operation costs are more complicated. D’Lima and Pirwitz (2000) concluded that jet-pulse systems are appropriate for the smallest kilns and reverse-air systems are preferred for all larger kilns, even though they may have higher installation costs for kilns of more modest size.

Corrosion in baghouses has been an important topic in the cement kiln control literature (Jansen and Mazeika, 2003; Biege and Shenk, 2001). A 2002 EPA rule [40 CFR Part 63 Subpart LLL (2002)] requires gas temperatures entering the control device not to exceed 400°F (205°C) in order to control dioxin emissions. Water sprays are usually utilized to control exhaust temperature, but adding water vapor to the exhaust stream while lowering exhaust temperature brings the gas near the dew point of some corrosive components. Corrosion issues can be addressed in a number of ways, but all add cost to the use of the control system.

The three components of corrosion are corrosive gases, condensation, and a corrodible surface; reducing any component will reduce corrosion. Corrosive gases can be reduced in a roller mill; this may be one of the most effective methods to reduce corrosion. Many of the gases are absorbed by the feed during the milling process and are therefore not available to form acids in the exhaust. Changing the feed may also reduce some of the acidic gases. Condensation is prevented most easily by keeping the exhaust temperature hot; however, when this is not allowed, it is best to maintain the exhaust temperature as high as possible, preventing drops which may allow acidic condensation. Insulating surfaces and carefully sealing unused sections of the control device can prevent exhaust from leaking into cool areas where it can condense and cause corrosion. Finally, corrosive-resistant materials and acid-resistant coatings can help reduce corrosion in control equipment.

Instead of a baghouse or an ESP, a combined system has become available, utilizing components of both systems. Whereas an in-series, hybrid system has the ESP and baghouse systems in independent compartments, this technology is described as “an ESP in which every other row of discharge electrodes is replaced by a single row of filter bags” (Gebert et al., 2003). In this new system, where the filter bags are directly adjacent or parallel to the ESP electrical field, ESP zones alternate with filter zones, allowing primary collection by the ESP and pre-ionization of the remaining dust for collection on the filter bags. A highly efficient expanded polytetrafluoroethylene (ePTFE) membrane is used as the filter fabric, which can remove an order of magnitude more of fine particulate than ordinary bags. During a pilot system test of a 225 m3/min (9000 acfm) slipstream from a coal-fired power plant in South Dakota, greater than 99.99% removal efficiency was shown. With the ESP fully engaged, bag cleaning was required only every 300 minutes, compared to every fifteen minutes when the ESP was not used. This system has been utilized in full-scale commercial operation at a cement kiln in Italy since September 2002, capturing dust from the cement kiln, raw mill and clicker cooler. Another similar filter is in operation since October 2002 at the coal-fired power plant in South Dakota mentioned above.

The synergy between the two technologies enables operation of the filter bags at high air-to-cloth (A/C) ratios, and, combined with the new compact size for filters, provides the following benefits for a cement plant:

- Ability to reach high control efficiencies in all operation modes,
- Continuous stable operation, and

- Lower operating costs, due to reduced number of system components.

4.3.4. VOC Controls

No controls which specifically targeted VOCs were identified for cement kilns.

4.4. Costs and Availability

4.4.1. Sulfur Dioxide Control

The SO_x control techniques applicable to the cement industry and the assumed SO_x reductions that the various control technologies can achieve are summarized in Table IV-4.

The achievable SO_x reductions vary greatly. Even when the same control technology is applied to kilns of the same type, the removal efficiency will depend on kiln operating parameters, uncontrolled SO_x emissions rate, and many other site-specific factors.

Wet-limestone scrubbers and spray dryers can be used as secondary control devices to reduce SO_2 emissions from a cement kiln.

Capital and operating costs for spray dryers and wet scrubbers as applied to cement kilns were computed by Young (2002). Both technologies were assumed to be installed *after* the existing APCD, which would allow the CKD to be recycled back to the kiln. If CKD is not recycled, there is a negative impact on the operating cost of the plant. Table IV-5 summarizes the capital and operating costs in terms of $ per ton of clinker produced for different types of kilns. The capital and operating costs of the spray dryer include a baghouse, new stack and new ID (induced draft) fan. The capital and operating costs for the wet scrubber include new fans and a new stack as well as a new wastewater treatment facility.

Another installation was made in 1998 at Castle Cement's Ribblesdale (UK) facility (Castle Cement, 2004). Scrubber installation cost £5 million and operational costs are about £750,000 annually. Emissions from one unit were reduced by 90%.

Table IV-4 SO_2 Control Techniques Applicable to Cement Kilns (Miller, 2001)

SO_2 reduction technique	**Applicable to kiln type**				**Range of removal efficiency**
	Long wet	**Long dry**	**Preheater**	**Precalciner**	
Process alterations	x	x	x	x	0-100%
Dry reagent injection			x	x	25-85%
Hot meal injection			x	x	0-30%
Spray dryer absorber		x	x	x	50-90%
Wet SO_2 scrubber	x	x	x	x	80-95%

Table IV-5 Capital and operating costs of spray dryers and wet scrubbers applied to cement kilns (Young, 2002)

		Spray Dryer		**Wet Scrubber**	
	Clinker capacity, tpy	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**
Small wet kiln	300,000	$54.67	$20.02	$47.00	$22.59
Medium wet kiln	600,000	$38.17	$14.09	$32.67	$17.58
Medium dry kiln	600,000	$39.75	$14.79	$31.83	$17.21
Large dry kiln	1,200,000	$23.17	$9.43	$20.42	$13.05
Medium preheater kiln	600,000	$17.92	$7.51	$15.83	$9.85
Medium precalciner kiln w/ bypass	600,000	$25.17	$10.20	$19.33	$11.42
Large preheater kiln	1,200,000	$10.96	$5.41	$10.83	$8.14

An alternative secondary control device for SO_2 was designed and applied as part of U.S. Department of Energy's Clean Coal Technology program. A co-project of Passamaquoddy Technology and Dragon Products Company in Thomaston, ME, the Passamaquoddy Technology Recovery Scrubber™ (Recovery Scrubber™) utilizes cement-kiln dust as a reagent for removing SO_2 from kiln exhaust gases (USDOE, 2001). Waste heat from the kiln is used to crystallize K_2SO_4, a saleable, fertilizer-grade by-product. The remaining cement kiln dust is returned to the kiln, significantly reducing particulate emissions, eliminating the need for removal of the dust to a landfill, and reducing the requirement for raw materials by about 10 percent. Sulfur dioxide was reduced by 82 to 98.5%, depending on scrubber inlet SO_2 rates. In addition, NO_X was reduced by about 25% and VOCs by 70%. Capital costs for a Recovery Scrubber™ were estimated at about $10.5 million in 1996 dollars, with operating and maintenance costs of $150,000 per year and electricity costs of $350,000 per year (787 kW at $0.06/kW).

4.4.2. Nitrogen Oxides Control

Table 6 presents a summary of NO_X controls that are feasible for cement kilns, the range of potential NO_X reductions from applying these controls, the cost effectiveness of the controls, and effects on other emissions when using these controls.

Table IV-6 Summary of the Feasibility of NO_X Controls for Cement Kilns

NO_X Reduction Technique	Technical Feasibility	NO_X Reduction Potential (%)[1]	Cost Effectiveness ($/ton NO_X removed)	Effect on Other Emissions	Reference
Process Modifications	In full-scale use	0 - 30 [15]	3,100 - 8,800	Unknown	16
Low NO_X Burners w/ Indirect Firing	In full-scale use	0 – 20 [10]	5,800 - 8,100	Unknown	16
Low NO_X Burners w/ Indirect Firing and Mid-kiln Tire Injection	In full-scale use	[49]	1 - 1,800	Unknown	17
Mid-Kiln Injection of Fuel, Riser Duct Firing Calciners	In full-scale use	0 – 30 [15]	5,100 -11,500	May increase CO, SO; hydrocarbon emission	16
CemStar	Wet kilns	20 - 50 [20]	0-600	Unknown	17
Low NO_X Precalciner	Have been installed on several full-scale kilns - Offered by several different vendors.	30 – 40 [30]	2,700 - 3,600	May Increase emissions CO, S02, and/ or hydrocarbons	16
SNCR	May be applicable only on preheater or precalciner kilns - limited data	15 – 65 [45]	900 - 1,200	May Increase emissions CO, NH3, and NH4+salts (detached plume)	17
Biosolids Injection	May be applicable only on preheater or precalciner kilns - limited data	[50]	100-1,800	May Increase emissions CO, NH3, and NH4+salts (detached plume	17

[1] Values in brackets are the assumed NO_X reductions used to calculate the estimated cost effectiveness of each Technology.

4.4.3. PM$_{2.5}$ Control

As discussed above, control of particulate matter in cement kilns is accomplished using baghouses and electrostatic precipitators. These processes are also used in electric utility generating units and industrial boilers. Capital and operating costs for fabric filters and ESPs as applied to cement kilns were computed by Young (2002) and are summarized in Table IV-7. The costs include the addition of a new fan.

Table IV-7 Capital and operating costs of baghouses and ESPs applied to cement kilns (Young, 2002)

		New ESP		New baghouse	
	Clinker capacity, tpy	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**	**Capital Cost, $/ton clinker**	**Annual Operating Cost, $/ton clinker**
Small wet kiln	300,000	$14.00	$3.35	$16.67	$3.81
Medium wet kiln	600,000	$11.00	$2.49	$13.00	$2.92
Medium dry kiln	600,000	$10.50	$2.54	$12.00	$2.78
Large dry kiln	1,200,000	$7.33	$1.51	$8.67	$1.96
Medium preheater kiln	600,000	$4.33	$1.03	$5.17	$1.17
Medium precalciner kiln w/ bypass	600,000	$5.33	$1.42	$6.33	$1.53
Large preheater kiln	1,200,000	$3.33	$0.74	$4.00	$0.90

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6.2. Industrial Boilers

For industrial boilers, many of the same control technologies for EGUs are applicable to this source category including: low sulfur coal, wet and dry FGD (or scrubber) technology for SO_2, combustion modifications and SCR and SNCR technology for NO_X, and ESP, fabric filter and wet scrubbing techniques for PM. However, industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus cost estimates for the same technologies will generally range, depending on the capacity of the boiler and typical operating conditions. High end cost estimates for NO_X removal can be over $10,000/ton.

6.3. Cement Kilns

Designing a system of emission controls for cement kilns are somewhat more complicated given that the quality of clinker produced in a kiln varies with characteristics of the combustion, it is possible to combine combustion technologies with post-combustion technologies for cement kilns in some cases and it is also possible to combine multiple combustion technologies on cement kilns. As a result, primary controls need to be selected carefully taking engineering and cost decisions into account for each specific kiln.

Control options for SO_2 include in-process removal, process changes (e.g. combustion optimization, flame shape adjustment or raw material changes), and the use of wet or dry scrubbers. For NO_X, both process modifications (e.g. combustion modifications, low-NO_X burners, secondary combustion or staged combustion) as well as post combustion controls need to be selected carefully. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading given that the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. In addition, PM technologies are affected by the presence of corrosive gases which can be reduced most effectively in a roller mill. While fabric filters (baghouses) and electrostatic precipitators are still the most common means of PM control at cement plants, a number of novel techniques and procedures are used to deal with the unique issues face by cement kilns.

Costs for SO_2 controls at cement kilns will vary widely depending on control options selected and process variables (e.g. whether material is recycled in the control process). Capital cost for typical wet/dry scrubbing post-combustion controls have been estimated in the $10-50/ton of clinker produced with operating costs in the $5-20/ton of clinker range. PM controls are similarly estimated in the $3-15/ton of clinker range for capital costs and $0-30/ton clinker for operating costs on an annual basis. NO_X has not been estimated on a per ton of clinker basis, but estimates vary between 0 and $10,000/ton of NO_X reduced.

6.4. Pulp Mills

Paper and pulp facilities have perhaps the widest range of operational configurations and thus possibilities for reducing pollutant emissions. A variety of

APPENDIX H

Appendix H

CALPUFF Modeling Results

```
v24.2002.b1559.bowa.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.brig.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.doso.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.grgu.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.grsm.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.hegl.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.isle.dat          : --- Number of days with Delta-Deciview  =>   0.50:       4   365
days
v24.2002.b1559.jari.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.ligo.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.lybr.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.maca.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.ming.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.sene.dat          : --- Number of days with Delta-Deciview  =>   0.50:      26   365
days
v24.2002.b1559.shen.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.sips.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days
v24.2002.b1559.voya.dat          : --- Number of days with Delta-Deciview  =>   0.50:       0   365
days

                                                                                      5.257   Max.
DV
```

```
v24.2003.b1559.bowa.dat       : --- Number of days with Delta-Deciview  =>   0.50:      3   365
days
v24.2003.b1559.brig.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.doso.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.grgu.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.grsm.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.hegl.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.isle.dat       : --- Number of days with Delta-Deciview  =>   0.50:      8   365
days
v24.2003.b1559.jari.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.ligo.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.lybr.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.maca.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.ming.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.sene.dat       : --- Number of days with Delta-Deciview  =>   0.50:     38   365
days
v24.2003.b1559.shen.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.sips.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days
v24.2003.b1559.voya.dat       : --- Number of days with Delta-Deciview  =>   0.50:      0   365
days

                                                                                 3.644   Max.
DV
```

```
v24.2004.b1559.bowa.dat        : --- Number of days with Delta-Deciview  =>   0.50:     7   366
days
v24.2004.b1559.brig.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.doso.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.grgu.dat        : --- Number of days with Delta-Deciview  =>   0.50:     5   366
days
v24.2004.b1559.grsm.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.hegl.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.isle.dat        : --- Number of days with Delta-Deciview  =>   0.50:    12   366
days
v24.2004.b1559.jari.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.ligo.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.lybr.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.maca.dat        : --- Number of days with Delta-Deciview  =>   0.50:     1   366
days
v24.2004.b1559.ming.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.sene.dat        : --- Number of days with Delta-Deciview  =>   0.50:    37   366
days
v24.2004.b1559.shen.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.sips.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days
v24.2004.b1559.voya.dat        : --- Number of days with Delta-Deciview  =>   0.50:     0   366
days

                                                                                  2.481   Max.
DV
```

Appendix 9F

St. Mary’s Cement BART Letter

DRAFT

BART Compliance Document
SMC

St. Mary's would apply for a permit modification with the limits described below, which would be effective December 31, 2012, under two conditions, namely:

1. DEQ can confirm in writing both that (i) the Emissions Limits below satisfy the Michigan BART rules, R 336.1970 and R 336.1971; and that (ii) the limits have been set in accordance with and satisfy the federal requirements for BART implementation, as detailed in 40 CFR 51.308 and 51.309, as well as 64 FR 35714 and 70 FR 39104.
2. The incorporation of these limits into the permit would be conditional on the resolution of those matters identified in the Notice of Violation dated September 29, 2009 from EPA.

FGKILNRAWMILLS
Flexible Group Conditions

I. <u>Emission Limit(s)</u>

Pollutant	Limit	Time Period	Monitoring Method
NOx	6.5 lbs/Ton of clinker	Effective January 1, 2013, Monthly average, as determined at the end of each calendar month.	SC VI.2 SC VI.5
NOx	4400 tons per year	Effective January 1, 2013, 12 month rolling time period determined at the end of each calendar month	SC VI.5
SOx	7.6 lbs/Ton of clinker	Effective January 1, 2013, Monthly average, as determined at the end of each calendar month.	SC VI.2 SC VI.4
SOx	3700 tons per year	Effective January 1, 2013, 12 month rolling time period determined at the end of each calendar month	SC VI.4

Appendix 9G

Emission Limits – Excerpts from ROP for St Mary’s Cement Inc.

FGKILNRAWMILLS
FLEXIBLE GROUP CONDITIONS

DESCRIPTION: This Flexible Group deals with mixing and grinding, then heating the ingredients to make cement. Included are limestone, shale, bottom ash, fly ash, bauxite, mill scales, slags, various sands, numerous iron sources, clay, overburden that are ground and mixed in EURAWMILLS. These raw materials are then sent to the EUKILN where they are heated and become clinker.

Emission Units: EURAWMILLS, EUKILN

POLLUTION CONTROL EQUIPMENT: Baghouse, Electrostatic Precipitator, Selective Non-Catalytic Reduction (SNCR)

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. PM	0.30 lb/ton of dry feed[2]		FGKILNRAWMILLS	SC V.1	**40 CFR 63.1343(b)(1)**
2. SO_2	2800 lbs/hour[2]	Hourly, as the average of each calendar day's emissions over the time of operation.	FGKILNRAWMILLS	SC VI.4, VI.10	**R 336.1201(3)**
3. SO_2	550 tons/month[2]	Calendar month.	FGKILNRAWMILLS	SC VI.4, VI.10	**R 336.1201(3)**
4. SO_2	4404 tons/year[2]	12-month rolling time period, as determined at the end of each calendar month.	FGKILNRAWMILLS	SC VI.4, VI.10	**R 336.1201(3)**
5. NO_x	6.50 lbs/ton of clinker produced[1]	Monthly average, as determined at the end of each calendar month, from May 1 through September 30.	FGKILNRAWMILLS	SC VI.2, VI.5, VI.11	**R 336.1801(4), Consent Order AQD No. 25-2006 Paragraph 10. A.1.**
6. NO_x	7.67 lbs/ton of clinker produced[2]	Monthly average, as determined at the end of each calendar month, from October 1 through April 30.	FGKILNRAWMILLS	SC VI.2, VI.5, VI.11	**R 336.1213, R 336.1910, Consent Order AQD No. 25-2006 Paragraph 10. A.1.**
7. D/F*	1.7×10^{-10} gr/dscf (TEQ) corrected to 7 percent oxygen[2#]		FGKILNRAWMILLS	SC III.4, V.2, VI.6, VI.17	**40 CFR 63.1343(b)(3)**
8. Nickel when burning 100% petroleum coke	0.36 lb/hour[1]		FGKILNRAWMILLS	SC V.3	**R 336.1224, R 336.1225**

Appendix 9H

Tilden Mining Company BART Technical Analysis

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

Table of Contents

List of Tables

List of Appendices

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_2). 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_2 emissions of 28,000 lb per day for Line 1 when coal is burned
- NOx 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[1].

Line 1 Cooler

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard[2].

Boilers 1 and 2

- SO_2 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_x is good combustion practices

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard[3].

Line 1 Dryer

- SO_2 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_x emissions will be controlled

- NO_x is good combustion practices

- PM emissions will be controlled as prescribed by the taconite maximum achievable control technology (MACT) standard[4].

Primary Crusher

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[1] 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing
[2] 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing
[3] 40 CFR Subpart 63 RRRRR-NESHAPS: Taconite Iron Ore Processing
[4] 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[5].

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.

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[5] 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.[6] 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_{10}, $PM_{2.5}$, SO_2, NO_x, 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

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[6] 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.[7] 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*

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[7] 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.*[8]

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.[9]" 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.[10]"

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.[11]" 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.[12]"

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

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[8] Federal Register 70, No. 128 (July 6, 2005): 39164
[9] Federal Register 70, No. 128 (July 6, 2005): 39165
[10] IBID
[11] IBID
[12] 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[13].” 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[14].

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[15].

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

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[13] IBID
[14] IBID
[15] 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[16], 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*

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[16] 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.*[17]

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[18]." 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[19]." 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[20]."

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

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[17] 40 CFR 51 Appendix Y. Page 361.
[18] 40 CFR 51 Appendix Y. Page 368.
[19] 40 CFR 51 Appendix Y. Page 369.
[20] 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[21]. 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_x, SO_2, and PM. Relative to NO_x and SO_2, PM is not a major visibility impairing pollutant. Further, the indurating furnaces are subject to the taconite MACT standard[22] 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_2*. 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*

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[21] Federal Register 70, no. 128 (July 6, 2005): 39107 and 39116

[22] 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_x and SO_2 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_x or SO_2. 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_x, SO_2, and PM.

Tilden facility has two process boilers that are subject to the boiler MACT[23]. 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_x and SO_2 where applicable for the process boilers and dryer.

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[23] 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

Emission Unit #	Emission Unit Description	NO_x Max 24-hr Actual Emissions (lbs/day)	SO_2 Max 24-hr Actual Emissions (lbs/day)	PM_{10} Max 24-hr Actual Emissions (lbs/day)	MACT PM Emission Limit (gr/dscf)	Stack Number	Actions Required
3.A	**Indurating Furnace**						
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_2 and NO_x
3.B	**PM-Only Taconite MACT Emission Units**						
EUPRIMARY CRUSHER	Primary Crusher 1	--	--	25.7	0.008	SVA0011570	None
EUCOOLER1	Line 1 Pellet Cooler Exhaust	--	--	5.9	0.008	SVP0025490	None
3.C	**Other Combustion Units**						
EUDRYER1	Line 1 Dryer	88.3	199.2	529.0	0.6[1]	SVP0082951	Full BART Analysis for SO_2 and NO_x
EUBOILER1	Process Boiler #1	463.3	1.5	300.0	0.6[1]	SVBLR.STK. T1	Full BART Analysis for SO_2 and NO_x
EUBOILER2	Process Boiler #2	463.3	1.5	300.0	0.6[1]	SVBLR.STK. T1	Full BART Analysis for SO_2 and NO_x

[1] 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[24], 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 are 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_x, SO_2, $PM_{2.5}$, PM_{10}, 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[25].

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

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[24] Federal Register 70, no. 128 (July 6, 2005): 39106.
[25] 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-revaluated. 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																
EUKILN1	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[26] 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:

- 98th Percentile: As defined by federal guidance, a source "contributes to visibility impairment" if the 98th percentile of any year's modeling results (i.e. 7th 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 98th 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 98th Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98th Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98th Percentile Value (deciview)	No. of days exceeding 0.5 deciview	Modeled 98th Percentile Value (deciview)	No. of days exceeding 0.5 deciview
IRNP	0.714	19	0.722	11	0.599	11	0.674	41

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[26] 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_2 and NO_x:

- 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 ºF 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_x is controlled through furnace design and type of fuel usage. During high ozone alert days, coal is burned to reduce the amount of NO_x generation. The SO_2 is controlled through furnace design and type of fuel usage. Kiln 1 has a SO_2 limit of 28,000 lbs per day.

5.A.i Sulfur Dioxide Controls

There are two sources of SO_2 emissions from the Line 1 Indurating Furnace:

1. SO_2 emissions from the trace amounts of sulfur in the iron concentrate and binding agents present in the green balls; and

2. SO_2 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_2 emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO_2 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_2 removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO_2 absorber.

The SO_2 control efficiency for a WWESP is dependent upon various process specific variables, such as SO_2 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_2 reduction for this BART analysis.

Wet Scrubbing (High and Low Efficiency)

Wet scrubbing, when applied to remove SO_2, 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_2 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_2 wet scrubber, the scrubber would require designs for removal efficiency up to 95% SO_2. Typical high efficiency SO_2 wet scrubbers are packed-bed spray towers using a caustic scrubbing solution. Whereas, a low efficiency SO_2 wet scrubber could have a control efficiency of 30% or lower. A low efficiency SO_2 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_2 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:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H2O + CO_2$$
$$CaSO_3 \bullet 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \bullet 2\ H_2O$$

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

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

When caustic (sodium hydroxide solution) is the scrubbing agent, the SO_2 removal reactions are as follows:

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

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_2 removal, additional equipment will be needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery; it is typically stabilized with fly ash for land filling. The calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur.

The normal SO_2 control efficiency range for SO_2 scrubbers 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_2 concentrations are the highest. The indurating furnace SO_2 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_2 concentration as well as creates higher flow rates to control. Additionally, the varying sulfur concentration within the pellet causes fluctuations of the SO_2 concentrations in the exhaust gas stream. This could also impact the SO_2 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_2 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_2 control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO_2 onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO_2 removal occurs as the flue gas flows through the filter cake on the bags. The normal SO_2 control efficiency range for dry SO_2 scrubbers is 70% to 90 % 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_2 reduction for this BART analysis.

Spray Dryer Absorption (SDA)

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter. When used to specifically control SO_2, the term flue-gas desulfurization (FGD) may also be used.

Based on the information contain with this report, SDA is considered a technically feasible technology for SO_2 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_2 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_2) for another (NO_x), as induration furnaces emit significantly less NO_x 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.[27]

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_2 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_2 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.[28] 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

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[27] Federal Register 70, no. 128 (July 6, 2005): 39164

[28] 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_2 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_2 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_2 Control Technology – Availability, Applicability, and Technical Feasibility

SO_2 Pollution Control Technology	Available?	Applicable?	Technically Feasible?
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_2 Control Technology Effectiveness

SO_2 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[29] and engineering experience, and were adjusted for the specific flow rates and pollutant concentrations.

Due to space considerations, 60%[30] 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

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[29] U.S. EPA, January 2002, *EPA Air Pollution Control Cost Manual, Sixth Edition*.

[30] 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_2 Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Total Annual Cost (MM$/yr)	Annualized Pollution Control Cost ($/ton)
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[31]. 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_2 Control Technology Impacts Assessment

Control Technology	Energy Impacts	Other Impacts
Wet Scrubber	Significant pressure drop results in higher electrical requirements	• Additional water consumption and wastewater generation • Increased facility water balance and water quality issues • Ponding for scrubber discharge will be limited because of site space constraints • Additional solid waste/sludge generation • Process downtime/lost production during installation

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_2 control technologies for Tilden Line 1 furnace is so high and

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[31] 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_2 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_2, the emissions from the sources undergoing a full BART SO_2 analysis were adjusted to reflect the projected 24-hour maximum SO_2 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_2 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_2		NO_x	
			SO_2	NO_x	% 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
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
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
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
14	SVP0051981 SVP0051711	EUKILN1	Wet Scrubber	Good Combustion Practice	80% 80%	40.0 14.6	0.0%	800.9 291.1

			Scenario Control Technology		SO_2		NO_x	
Control Scenario	SV #	Emission Unit	SO_2	NO_x	% 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% 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
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
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
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

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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$_2$ 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 46.44075383	-87.65340738 -87.65132336	240 160	1474	19.3 13.5	842,000 306,000	300 300
	SVP0082951	EUDRYER1	46.44075383	-87.65132336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.65412418	130	1474	7.5	192,000	350

Post-Control Visibility Impacts Modeling Results

Results of the post-control visibility impacts modeling for SO_2 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_x controls are presented in Section 6.

Table 5-7 Post-Control SO_2 Modeling Scenarios - Visibility Modeling Results

		2002		2003		2004		2002 – 2004 Combined	
Scenario #	**Class I Area with Greatest Impact**	**Modeled 98th Percentile Value (deciview)**	**No. of days exceeding 0.5 deciview**	**Modeled 98th Percentile Value (deciview)**	**No. of days exceeding 0.5 deciview**	**Modeled 98th Percentile Value (deciview)**	**No. of days exceeding 0.5 deciview**	**Modeled 98th 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_2 Modeling Scenarios - Visibility Improvements

Scenario	Modeling Results								
	0	2002		2003		2004		2002-2004	
	Limiting Class I Area	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-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

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5.A.ii Nitrogen Oxide Controls

To be able to control NO_x it is important to understand how NO_x is formed. There are three mechanisms by which NO_x production occurs: thermal, fuel and prompt NO_x.

- Fuel bound NO_x is formed from fuel combustion as nitrogen compounds in the fuel are oxidized.
- Thermal 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. In taconite furnaces, thermal NO_x production is a function of the residence time, free oxygen, and temperature, primarily in the flame area of the furnace.
- Prompt NO_x is a form of thermal 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 NO_x are emitted as prompt NO_x.

The majority of NO_x is emitted as NO. Minor amounts of NO_2 are formed in the furnaces.

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

With the understanding of how NO_x 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_x emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit 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 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_x 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_x emissions. For this technology to be effective, the combustion conditions must have the ability to be controlled at the burner tip.

The normal NO_x 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_x Burners

Low-NO_x burner (LNB) technology utilizes advanced burner design to reduce NO_x 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_x formation is limited by a rich (high fuel) condition. Oxygen levels and flame temperatures are low; this results in less NO_x 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_x formation. However, the technology vendor will not guarantee that ported kilns will reduce NO_x emissions because controlling the oxygen in the firing zone is not possible due to the flow of air from the pellet cooler[32]. Any reduction in NO_x 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_x 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

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[32] Telephone conversation with Metso, July 18, 2006.

gas. Reduction of NO_x 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_x) for another (SO_2). 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.[33]

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_x 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.[34] 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.

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[33] Federal Register 70, no. 128 (July 6, 2005): 39164

[34] The coal processing description provided herein is based on the K-Fuel® 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_x 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_x formation.

- At some operations, the operating parameters which generally influence the rate of NO_x 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_x formation may not be dependent upon controllable operating parameters. In the absence of controllable parameters, process optimization would not be effective at controlling NO_x 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_x 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_x 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_x, unburdened hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO_x 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_x is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NO_x removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \qquad (1)$$

$$[UBH] + NO \rightarrow N_2 + CO_2 + H_2O \qquad (2)$$

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_x control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. NO_x is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \tag{1}$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \tag{2}$$

A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO_x decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670ºF, 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_2 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_2 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 significantly 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 had been shown to oxidize mercury. Oxidized mercury can be absorbed by the local environment and have 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_x. In the system, the NO_x 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_x® and LoTOx®.

$$\mathrm{NO} + \mathrm{O_3} \rightarrow \mathrm{NO_2} + \mathrm{O_2} \tag{1}$$

$$\mathrm{NO_2} + \mathrm{O_3} \rightarrow \mathrm{NO_3} + \mathrm{O_2} \tag{2}$$

$$\mathrm{NO_3} + \mathrm{NO_2} \rightarrow \mathrm{N_2O_5} \tag{3}$$

$$\mathrm{N_2O_5} + \mathrm{H_2O} \rightarrow 2\mathrm{HNO_3} \tag{4}$$

$$\mathrm{HNO_3} + \mathrm{NaOH} \rightarrow \mathrm{NaNO_3} + \mathrm{H_2O} \tag{5}$$

Low Temperature Oxidation (Tri-$NO_x^®$)

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$\mathrm{O_3} + \mathrm{NO} \rightarrow \mathrm{O_2} + \mathrm{NO_2} \tag{1}$$

$$2\mathrm{NaOH} + 2\mathrm{NO_2} + \tfrac{1}{2}\,\mathrm{O_2} \rightarrow 2\mathrm{NaNO_3} + \mathrm{H2O} \tag{2}$$

Tri-NO_x® 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_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-NO_x® is typically applied at small to medium sized sources with high NO_x concentration in the exhaust gas (1,000 ppm NO_x). NO_x concentrations in the exhaust at Tilden are typically less than 200 ppm. Therefore, Tri-NO_x® is not applicable to taconite processing and will not be analyzed further in this BART analysis.

Low Temperature Oxidation (LoTOx®)

BOC Gases' Lo-TOx® is an example of a version of an LTO system. LoTOx® technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx® is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO_x control. Ozone is generated from pure oxygen. In order for LoTOx® 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® 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® 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 (Fe_3O_4) which would react with the ozone to form hematite (Fe_2O_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 SO_2, converting the material to 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_x 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_x Control Technology – Availability, Applicability, and Technical Feasibility

NO_x Pollution Control Technology	Available?	Applicable?	Technically Feasible?
External Flue Gas Recirculation (EFGR)	Yes	No	No
Low NO_x 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

NO_x Pollution Control Technology	Available?	Applicable?	Technically Feasible?
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_x Control Technology Effectiveness

NO_x Pollution Control Technology	Approximate Control Efficiency
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_x 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_x Control Cost Summary

Control Technology	Installed Capital Cost (MM$)	Total Annual Cost (MM$/yr)	Annualized Pollution Control Cost ($/ton)
SCR **With conventional reheat**	$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[35]. 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.

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[35] 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_x 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_x Control Technology Impacts Assessment

Control Technology	Energy Impacts	Other Impacts
SCR with Reheat	Reheat would require additional natural gas use.	• Ammonia slip, which contributes to regional haze. Ammonia reacts with NO_x to form ammonium nitrate and SO_2 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. • Ammonia emissions will increase condensable PM emissions that will have possible PSD permitting implications. • Ammonia deposition onto nearby lakes and waters of the state and contribute nutrients and undesirable biological growth. • Additional safety and regulatory concerns associated with ammonia storage on site. • Possible oxidation of elemental mercury.

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_x 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_x, the emissions from the sources undergoing a full BART NO_x analysis were adjusted to reflect the projected 24-hour maximum NO_x 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_x control technologies. Table 5-14 provides a summary of the modeling input data.

Table 5-13 Post-Control NO_x Modeling Scenarios

Control Scenario			Scenario Control Technology		SO_2		NO_x	
	SV #	Emission Unit	SO_2	NO_x	% 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
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
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
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
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

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO_2		NO_x	
			SO_2	NO_x	% 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_2		NO_x	
			SO_2	NO_x	% 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 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
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 5-14 Post-Control NO_X 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 46.44075383	-87.65340738 -87.65132336	240 160	1474	19.3 13.5	842,000 306,000	300 300
	SVP0082951	EUDRYER1	46.44075383	-87.65132336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.65412418	130	1474	7.5	192,000	350

Post-Control Visibility Impacts Modeling Results

Results of the post-control visibility impacts modeling for NO_X 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_2 controls are presented in section 6.

Table 5-15 Post-Control NO_X Modeling Scenarios - Visibility Modeling Results

	Modeling Results								
		2002		2003		2004		2002-2004	
Scenario	Limiting Class I Area	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_X Modeling Scenarios - Visibility Improvements

	Modeling Results								
		2002		2003		2004		2002-2004	
Scenario	Limiting Class I Area	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th 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
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_2 emissions from these boilers. The boilers have low emissions of SO_2 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_2 emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO_2 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_2 removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO_2 absorber.

The SO_2 control efficiency for a WWESP is dependent upon various process specific variables, such as SO_2 flue gas concentration and fuel used. Based on the information contained within this report, a WWESP is considered a technically feasible technology for SO_2 reduction for this BART analysis.

Wet Scrubbing (High and Low Efficiency)

Wet scrubbing, when applied to remove SO_2, 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_2 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:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H2O + CO_2$$
$$CaSO_3 \bullet 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \bullet 2\ H_2O$$

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

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

When that caustic (sodium hydroxide solution) is the scrubbing agent, the SO_2 removal reactions are as follows:

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

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_2 removal, additional equipment will be needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery; it is typically stabilized with fly ash for land filling. The calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur.

The normal SO_2 control efficiency range for SO_2 scrubbers 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_2 concentrations are the highest. The process boiler's exhaust would not have a high SO_2 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_2 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_2 control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO_2 onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO_2 removal occurs as the flue gas flows through the filter cake on the bags. The normal SO_2 control efficiency range for dry SO_2 scrubbers is 70% to 90 % for coal fired utility boilers.

Based on the information contained within this report, DSI is considered a technically feasible technology for SO_2 reduction for this BART analysis.

Spray Dryer Absorption (SDA)

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$. 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 SO2 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_2 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_2 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_2 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.[36]

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_2 reductions.

STEP 2 Conclusion

Based upon the determination within Step 2, the remaining SO_2 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.

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[36] Federal Register 70, no. 128 (July 6, 2005): 39164

Table 5-17 Process Boiler SO_2 Control Technology – Availability, Applicability, and Technical Feasibility

SO_2 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_2 Control Technology Effectiveness

SO_2 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[37] as shown in the following equation:

Cost of equipment A = Cost of equipment B * (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[38] 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_2 Control Cost Summary

Control Technology	Installed Capital Cost ($)	Total Annual Cost ($/yr)	Annualized Pollution Control Cost ($/ton)
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

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[37] M.S. Peters and K.D. Timmerhaus, December, 2002 *Plant Design and Economics for Chemical Engineers, Fifth Edition.*

[38] 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[39]. 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_2 technologies are cost effective for the process boilers, the energy and non-air quality impacts were not assessed for the SO_2 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_2 technologies are cost effective for the process boilers, the visibility impacts were not evaluated.

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[39] Michigan Department of Environmental Quality May 12, 2006 meeting.

5.B.ii Nitrogen Oxide Controls

To be able to control NO_x it is important to understand how NO_x is formed. There are three mechanisms by which NO_x production occurs: thermal, fuel and prompt NO_x.

- Fuel bound NO_x is formed as nitrogen compounds in the fuel is oxidized in the combustion process.
- Thermal 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 NO_x production is a function of the residence time, free oxygen, and temperature.
- Prompt NO_x is a form of thermal 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 NO_x are emitted as prompt NO_x.

The majority of NO_x is emitted as NO. Minor amounts of NO_2 are formed in the boiler.

5.B.ii.aSTEP 1 – Identify All Available Retrofit Control Technologies

With the understanding of how 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 NO_x emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit 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_x 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_x 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 NOx Burners (LNB)

Low-NO_x burner (LNB) technology utilizes advanced burner design to reduce NO_x 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, NOx 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 NOx 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_x 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_x formation. Low NO_x burners typically achieve NO_x 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_x 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_x control technology typically used in boilers and is primarily geared to reduce thermal NO_x. 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_x by lowering peak combustion temperature and limiting the availability of oxygen in the combustion zone where NO_x is most likely to be formed. OFA is considered compatible with the LNB. The estimated NO_x 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_x reduction for this BART analysis.

Induced Flue Gas Recirculation (IFGR)

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 50-75%.

Based on the information contained within this report, IFGR is considered a technically feasible technology for NO_x 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_x emissions through alternative fuel usage, the source must be currently burning a high NO_x 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.[40]

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_x. 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_x 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,

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[40] Federal Register 70, no. 128 (July 6, 2005): 39164

absorbing, or adsorbing NO_x 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_x, unburdened hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO_x 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_x is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NO_x removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \tag{1}$$

$$[UBH] + NO \rightarrow N_2 + CO_2 + H_2O \tag{2}$$

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_x control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. NO_x is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \tag{1}$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \tag{2}$$

A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO_x decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670ºF, 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_2 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_2 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_2, 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:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O \quad (1)$$

$$NH_3 + \tfrac{1}{4}O_2 \rightarrow NO + 3/2H_2O \quad (2)$$

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_x 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_x. In the system, the NO_x 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_x® and LoTOx®.

$$NO + O_3 \rightarrow NO_2 + O_2 \quad (1)$$

$$NO_2 + O_3 \rightarrow NO_3 + O_2 \tag{2}$$

$$NO_3 + NO_2 \rightarrow N_2O_5 \tag{3}$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3 \tag{4}$$

$$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O \tag{5}$$

Low Temperature Oxidation (Tri-NO_x®)

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$O_3 + NO \rightarrow O_2 + NO_2 \tag{1}$$

$$2NaOH + 2NO_2 + \tfrac{1}{2}\, O_2 \rightarrow 2NaNO_3 + H2O \tag{2}$$

Tri-NO_x® 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_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-NO_x® is typically applied at small to medium sized sources with high NO_x concentration in the exhaust gas (1,000 ppm NO_x).

Low Temperature Oxidation (LoTOx®)

BOC Gases' Lo-TOx® is an example of a version of an LTO system. LoTOx® technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx® is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO_x control. Ozone is generated from pure oxygen. In order for LoTOx® 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® 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_x 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_x Control Technology – Availability, Applicability and Technical Feasibility

NOx Pollution Control Technology	Available?	Applicable?	Technically Feasible?
External Flue Gas Recirculation (EFGR)	Yes	Yes	No
Low-NOx Burners (LNB)	Yes	Yes	Yes
Low NOx 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 NOx Control Technology Effectiveness

NOx Pollution Control Technology	Approximate Control Efficiency
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_x 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_x Control Cost Summary

Control Technology	Installed Capital Cost ($)	Total Annual Cost ($/yr)	Annualized Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
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[41]. Therefore, all air pollution controls with annualized costs less than this screening threshold will be evaluated for visibility improvement, energy and other impacts.

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[41] 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_x 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_x 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_X 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_X modeling analysis, the emissions from the sources undergoing a full BART NO_x analysis were adjusted to reflect the projected 24-hour maximum NO_x 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_x 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_X 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_2 controls are presented in section 6.

Table 5-27 Process Boiler Post-BART Modeling Scenarios

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO_2		NO_x	
			SO_2	NO_x	% 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$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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 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 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

Control Scenario	SV #	Emission Unit	Scenario Control Technology		SO$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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_2		NO_x	
			SO_2	NO_x	% 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 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 5-28 Process Boiler Post-BART NO_x 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 46.44075383	-87.65340738 -87.65132336	240 160	1474	19.3 13.5	842,000 306,000	300 300
	SVP0082951	EUDRYER1	46.44075383	-87.65132336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.65412418	130	1474	7.5	192,000	350

Table 5-29 Process Boiler Post-BART NO$_x$ Modeling Scenarios - Visibility Modeling Results

Scenario	Modeling Results								
		2002		2003		2004		2002-2004	
	Limiting Class I Area	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_x Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results

	Modeling Results								
		2002		2003		2004		2002-2004	
Scenario	Limiting Class I Area	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th 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_2 emissions from the dryer. The Line 1 Dryer has low emissions of SO_2 due to the low sulfur content of the permitted fuels. In addition, collateral SO_2 reductions occur within the existing impingment scrubbers, and therefore the existing scrubber is considered a low-efficiency SO_2 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_2 emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit SO_2 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_2 removal, caustic is added to the water spray system, allowing the WWESP spray system to function as an SO_2 absorber.

The SO_2 control efficiency for a WWESP is dependent upon various process specific variables, such as SO_2 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_2 wet scrubber. The addition of a WWESP would act as a polishing SO_2 control device and would experience reduced control efficiency due to lower SO_2 inlet concentrations.

Based on the information contained within this report, a WWESP is considered a technically feasible technology for SO_2 reduction for this BART analysis.

Wet Scrubbing (High and Low Efficiency)

Wet scrubbing, when applied to remove SO_2, 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_2 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:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H2O + CO_2$$

$$CaSO_3 \bullet 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \bullet 2\ H_2O$$

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

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + 1/2\ H_2O$$

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

When that caustic (sodium hydroxide solution) is the scrubbing agent, the SO_2 removal reactions are as follows:

$$Na+ + OH- + SO_2 + \rightarrow Na_2SO_3$$

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

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_2 removal, additional equipment will be needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery; it is typically stabilized with fly ash for land filling. The calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur.

The normal SO_2 control efficiency range for SO_2 scrubbers 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_2 concentrations are the highest. The dryer and process boiler's exhaust would not have a high SO_2 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_2 in the exhaust. The addition of an additional SO_2 scrubber would act as a polishing SO_2 control device and would experience reduced control efficiency due to lower SO_2 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_2 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_2 emissions. The SO_2 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_2 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_2 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_2 control technology in which pulverized lime or limestone is directly injected into the duct upstream of the fabric filter. Dry sorption of SO_2 onto the lime or limestone particle occurs and the solid particles are collected with a fabric filter. Further SO_2 removal occurs as the flue gas flows through the filter cake on the bags. The normal SO_2 control efficiency range for dry SO_2 scrubbers is 70% to 90 % 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_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$. 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 SO2 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_2 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_2 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.[42]

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[42] 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_2 reductions.

STEP 2 Conclusion

Based upon the determination within Step 2, the remaining SO_2 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_2 Control Technology – Availability, Applicability, and Technical Feasibility

SO_2 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_2 Control Technology Effectiveness

SO_2 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:

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

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[43] 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_2 Control Cost Summary

Control Technology	Installed Capital Cost ($)	Total Annual Cost ($/yr)	Annualized Pollution Control Cost ($/ton)
Wet Scrubber	$3,898,490	$684,207	$25,103
Wet ESP (WWESP)	$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

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[43] 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[44]. 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_2 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_2 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_2 technologies are cost effective for the process boilers, the visibility impacts were not evaluated.

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[44] Michigan Department of Environmental Quality May 12, 2006 meeting.

5.C.ii Nitrogen Oxide Controls

To be able to control NO_x it is important to understand how NO_x is formed. There are three mechanisms by which NO_x production occurs: thermal, fuel and prompt NO_x.

- Fuel bound NO_x is formed as nitrogen compounds in the fuel is oxidized in the combustion process.

- Thermal 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 NO_x production is a function of the residence time, free oxygen, and temperature.

- Prompt NO_x is a form of thermal 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 NO_x are emitted as prompt NO_x.

The majority of NO_x is emitted as NO. Minor amounts of NO_2 are formed in the dryer.

5.C.ii.aSTEP 1 – Identify All Available Retrofit Control Technologies

With the understanding of how 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 NO_x emission reduction. Within Step 1, the technical feasibility of the control option was also discussed and determined. The following describes retrofit 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_x 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_x 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 NOx Burners (LNB)

Low-NO_x burner (LNB) technology utilizes advanced burner design to reduce NO_x 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, NOx 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 NOx 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_x 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_x formation. Low NO_x burners typically achieve NO_x 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_x 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_x control technology typically used in boilers and is primarily geared to reduce thermal NO_x. 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_x by lowering peak combustion temperature and limiting the availability of oxygen in the combustion zone where NO_x is most likely to be formed. OFA is considered compatible with the LNB. The estimated NO_x 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_x reduction for this BART analysis.

Induced Flue Gas Recirculation (IFGR)

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 50-75%.

Based on the information contained within this report, IFGR is considered a technically feasible technology for NO_x 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_x emissions through alternative fuel usage, the source must be currently burning a high NO_x 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.[45]

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_x. 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_x 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,

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[45] Federal Register 70, no. 128 (July 6, 2005): 39164

absorbing, or adsorbing NO_x 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_x, unburdened hydrocarbons (UBH), and carbon monoxide (CO). Typically, NSCR can achieve NO_x 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_x is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2). The most important reactions for NO_x removal are:

$$2CO + 2NO \rightarrow 2CO_2 + N_2 \qquad (1)$$

$$[UBH] + NO \rightarrow N_2 + CO_2 + H_2O \qquad (2)$$

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_x control technology in which ammonia (NH_3) is injected into the flue gas stream in the presence of a catalyst. NO_x is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad (1)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O \qquad (2)$$

A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO_x decomposition. SCR requires a temperature range of about 570°F – 850°F for a normal catalyst. At temperature exceeding approximately 670ºF, 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_2 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_2 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_2, 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:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O \quad (1)$$

$$NH_3 + \tfrac{1}{4}O_2 \rightarrow NO + 3/2H_2O \quad (2)$$

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_x 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_x. In the system, the NO_x 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_x® and LoTOx®.

$$NO + O_3 \rightarrow NO_2 + O_2 \tag{1}$$

$$NO_2 + O_3 \rightarrow NO_3 + O_2 \tag{2}$$

$$NO_3 + NO_2 \rightarrow N_2O_5 \tag{3}$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3 \tag{4}$$

$$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O \tag{5}$$

Low Temperature Oxidation (Tri-$NO_x^{®}$)

This technology uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. The reactions are as follows:

$$O_3 + NO \rightarrow O_2 + NO_2 \tag{1}$$

$$2NaOH + 2NO_2 + ½\, O_2 \rightarrow 2NaNO_3 + \mathrm{H2O} \tag{2}$$

Tri-$NO_x^{®}$ 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_2. Subsequent stages reduce NO_2 to nitrogen gas, while the oxygen becomes part of a soluble salt. Tri-$NO_x^{®}$ is typically applied at small to medium sized sources with high NO_x concentration in the exhaust gas (1,000 ppm NO_x).

Low Temperature Oxidation (LoTOx®)

BOC Gases' Lo-TOx® is an example of a version of an LTO system. LoTOx® technology uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). This can be done in the same scrubber used for particulate or sulfur dioxide removal, The N_2O_5 is converted to HNO_3 in a scrubber, and is removed with lime or caustic. Ozone for LoTOx® is generated on site with an electrically powered ozone generator. The ozone generation rate is controlled to match the amount needed for NO_x control. Ozone is generated from pure oxygen. In order for LoTOx® 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® 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_x 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_x Control Technology – Availability, Applicability and Technical Feasibility

NOx Pollution Control Technology	Available?	Applicable?	Technically Feasible?
External Flue Gas Recirculation (EFGR)	Yes	Yes	No
Low-NOx 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 NOx Control Technology Effectiveness

NOx Pollution Control Technology	Approximate Control Efficiency
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_x 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_x Control Cost Summary

Control Technology	Installed Capital Cost ($)	Total Annual Cost ($/yr)	Annualized Pollution Control Cost ($/ton)	Incremental Control Cost ($/ton)
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[46]. 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

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[46] 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_x 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_x 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/FGR	- Minimal energy impacts.	- Increase in CO emissions - Potential for steam tube wastage due to longer combustion flame.

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_X 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_X modeling analysis, the emissions from the sources undergoing a full BART NO_x analysis were adjusted to reflect the projected 24-hour maximum NO_x 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_x 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_X 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_2 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_2		NO_x	
			SO_2	NO_x	% 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_2		NO_x	
			SO_2	NO_x	% 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$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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

			Scenario Control Technology		SO_2		NO_x	
Control Scenario	**SV #**	**Emission Unit**	**SO_2**	**NO_x**	**% 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_2		NO_x	
			SO_2	NO_x	% 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_2		NO_x	
			SO_2	NO_x	% 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_x 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 46.44075383	-87.65340738 -87.65132336	240 160	1474	19.3 13.5	842,000 306,000	300 300
	SVP0082951	EUDRYER1	46.44075383	-87.65132336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.65412418	130	1474	7.5	192,000	350

Table 5-38 Line 1 Dryer Post-BART NO$_x$ Modeling Scenarios - Visibility Modeling Results

Scenario	Modeling Results								
		2002		2003		2004		2002-2004	
	Limiting Class I Area	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
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$_x$ Modeling Scenarios – Comparison of Visibility Modeling Results to Baseline Modeling Results

Scenario	Modeling Results								
		2002		2003		2004		2002-2004	
	Limiting Class I Area	Improved Modeled 98th Percentile Value (∆-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (∆-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (∆-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (∆-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_2 and NO_x 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_x, SO_2 and PM_{10} 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_x 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$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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_2		NO_x	
			SO_2	NO_x	% 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$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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_2		NO_x	
			SO_2	NO_x	% 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_2		NO_x	
			SO_2	NO_x	% 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$_2$		NO$_x$	
			SO$_2$	NO$_x$	% 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$_X$ 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 46.44075383	-87.65340738 -87.65132336	240 160	1474	19.3 13.5	842,000 306,000	300 300
	SVP0082951	EUDRYER1	46.44075383	-87.65132336	119	1474	6.3	57,135	150
	SVBLR.STK.T1	EUBOILER1 EUBOILER2	46.44091784	-87.65412418	130	1474	7.5	192,000	350

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

	Modeling Results								
		2002		2003		2004		2002-2004	
Scenario	Limiting Class I Area	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
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								
		2002		2003		2004		2002-2004	
	Limiting Class I Area	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th Percentile Value (Δ-dV)	Decreased No. of Days exceeding 0.5 dV	Improved Modeled 98th 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

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

			Scenario Control Technology				
Control Scenario	SV #	Emission Unit	SO$_2$	NO$_x$	Annualized Cost ($/yr)	Improved Modeled 98th Percentile Value (Δ-dV)	$/dV
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 SO$_2$	Scenario Control Technology NO$_x$	Annualized Cost ($/yr)	Improved Modeled 98th Percentile Value (Δ-dV)	$/dV
			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 98th Percentile Value (Δ-dV)	$/dV
			SO$_2$	NO$_x$			
	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 98th Percentile Value (Δ-dV)	$/dV
			SO$_2$	NO$_x$			
	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 98th Percentile Value (Δ-dV)	$/dV
			SO_2	NO_x			
			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 98th Percentile Value (Δ-dV)	$/dV
			SO_2	NO_x			
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 98th Percentile Value (Δ-dV)	$/dV
			SO_2	NO_x			
			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_2, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO_2 emissions limit is 28,000 lb per day for Line 1 when coal is burned.

For NO_x, the reduction due to good combustion practices on Line 1 is selected as BART. Other add-on controls for NO_x are not cost effective. The corresponding NOx 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_2, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO_2 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_x, the reduction due to good combustion practices is selected as BART. Other add-on controls for NO_x 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_2, add-on controls are not cost effective. Therefore, BART is determined to be existing controls. The corresponding SO_2 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_x, the reduction due to good combustion practices is selected as BART. Other add-on controls for NO_x 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)

12/28/2006

BART Report - Attachment A: Emission Control Cost Analysis

Table A.1: Grate Kiln Cost Summary

NO_x 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_2 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

Michigan Operations - West (Tilden)

12/27/2006

BART Report - Attachment A: Emission Control Cost Analysis

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

NO_x 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
Selective Catalytic Reduction (SCR) with Reheat							
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**
Low NO_X Burner / Flue Gas Recirculation							
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**
Regenerative Selective Catalytic Reduction (R-SCR)							
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**
Low NO_X Burner / Overfire Air (OFA)							
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**
Low NO_X Burner							
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**
Selective Non-Catalytic Reduction (SNCR)							
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_2 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
Spray Dry Baghouse							
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**
Wet Scrubber							
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**
Wet ESP (WWESP)							
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**
DSI Baghouse							
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

CALMET				
Variable	Description	Value	Default	Comments
Input Group 2				
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	
Input Group 4				
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
Input Group 5				
BIAS	Surface/upper-air weighting factors	-1, 11*0	12*0	Surface Layer is set to -1 since IEXTRP=-1
Input Group 6				
ITPROG	3D temperature from observations or from prognostic data?	0	Y	Inclusion of Surface and Upper Air

CALPUFF				
Variable	Description	Value	Default	Comments
Input Group 4				
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
SO2 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.[1]	SO_2 Pollution Control Technology [2]	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_2 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_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$
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 throught 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 biomedia 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_2	N	---	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO_2 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_2 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
SO2 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.[1]	**SO_2 Pollution Control Technology [2]**	**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**
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.
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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NOx
17	Copper-Oxide	N	---	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO_2 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 NOx in the presence of ammonia (NH_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 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/eogapti1/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
SO2 Control
Process Boilers

Available and Applicable Review

DRAFT

Revised: December 1, 2006

		Step 1	**Step 2**				**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.[1]	**SO_2 Pollution Control Technology [2]**	**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?**	**Comments**	**Basic Principle**
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_2 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_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$
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 biomedia 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_2	No	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO_2 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_2 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

		Step 1	**Step 2**				**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.[1]	**SO_2 Pollution Control Technology** [2]	**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?**	**Comments**	**Basic Principle**
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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, 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_2 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_2.
18	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 vapor and then condensed to a concentrated liquid sulfuric acid (H_2SO_4).
19	Cold Plasma	No	---	---	---	Research level	

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

		Step 1	Step 2				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. [1]	**SO_2 Pollution Control Technology** [2]	**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?**	**Comments**	**Basic Principle**

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

		Step 1	Step 2				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.[1]	NO$_x$ Pollution Control Technology[2]	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?	Comments	Basic Principle
				Combustion Controls			
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_2 rather than NOx
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-NOx Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NOx 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 NOx 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

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		Step 1	Step 2				
Reference No.[1]	**NO$_x$ Pollution Control Technology[2]**	**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?**	**Comments**	**Basic Principle**
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_2.
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.
Post Combustion Controls							
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_2) and carbon dioxide (CO_2).
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

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Reference No.[1]	NO_x Pollution Control Technology[2]	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?	Comments	Basic Principle
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_3) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N_2 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_2, 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_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 vapor and then condensed to a concentrated liquid sulfuric acid (H_2SO_4).
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.

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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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NOx is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO_2 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_2.
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/eogapti1/module6/index.htm
c) New and Emerging Environmental Technologies, http://neet.rti.org/
d) ND BART Reports

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						Combustion Controls	
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_2 rather than NOx
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-NOx Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NOx 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 NOx 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

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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_2.
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.
Post Combustion Controls							
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, NOx is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2).

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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
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_3) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N_2 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_2, 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 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.

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30	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 vapor and then condensed to a concentrated liquid sulfuric acid (H_2SO_4).
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.
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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NOx is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO_2 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_2.
36	Cold Plasma	No	---	---	---	Research Level	

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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.

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						Combustion Controls	
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_2 rather than NOx
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-NOx Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NOx 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 NOx 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

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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_2.
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)
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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.
Post Combustion Controls							
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, NOx is reduced by CO, resulting in nitrogen (N_2) and carbon dioxide (CO_2).

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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
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_3) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N_2 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_2, 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 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.

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30	SNOX	No	---	---	---	Early commercial development stage	Catalytic reduction of NOx in the presence of ammonia (NH_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 vapor and then condensed to a concentrated liquid sulfuric acid (H_2SO_4).
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.
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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NOx is converted to nitrogen and oxygen.
35	Copper-Oxide	No	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO_2 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_2.
36	Cold Plasma	No	---	---	---	Research Level	

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Reference No.[1]	**NO$_x$ Pollution Control Technology[2]**	**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?**	**Comments**	**Basic Principle**
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/eogapti1/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

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		Step 1	Step 2					
Reference No.[1]	SO_2 Pollution Control Technology[2]	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_2 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_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$
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 throught 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 biomedia 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_2	N	---	---	---	---	Research level	An aqueous solution of proprietary diamine captures SO_2 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_2 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.

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Reference No.[1]	SO_2 Pollution Control Technology[2]	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
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_2, NOx, and mercury are oxidized to nitrogen dioxide (NO_2), 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_2 and NOx from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NOx
17	Copper-Oxide	N	---	---	---	---	Absorption and SCR. Experience limited to pilot scale.	SO_2 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 NOx in the presence of ammonia (NH_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 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.
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2) b) US EPA Basic Concepts in Environmental Science, Module 6, http://www.epa.gov/eogapti1/module6/index.htm
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NOx Control
Dryer

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Revised: December 1, 2006

		Step 1	Step 2				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.[1]	**NO$_x$ Pollution Control Technology [2]**	**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?**	**Comments**	**Basic Principle**
				Combustion Controls			
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_2 rather than NOx
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-NOx Burners	Yes	Yes	Yes	Yes		Burners are designed to reduce NOx 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 NOx 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

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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_2.
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.
Post Combustion Controls							
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_2) and carbon dioxide (CO_2).
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

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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_3) is injected into the flue gas stream in the presence of a catalyst to convert NOx into N_2 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_2, 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_3), followed by catalytic oxidation of SO_2 to SO_3. The exit gas from the SO_3 converter passes through a novel glass-tube condenser in which the SO_3 is hydrated to H_2SO_4 vapor and then condensed to a concentrated liquid sulfuric acid (H_2SO_4).
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.

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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

		Avg. Expected Values ($/ton)		Limiting/Marginal values ($/ton)		Comments
Reference	Regulatory Body/Rule	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 reasonble. 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 (Technologly 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_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), nitrous oxide (NO_x), 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.[1] 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.*[2]

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:

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[1] 40 CFR 51 Appendix Y

[2] 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.[3]” 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.[4]”

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.[5]” 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.[6]”

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[7].” This also involves the identification of “un-resolvable technical difficulties.” However, when the technical difficulties are merely a matter of increased cost, the technology

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[3] Federal Register 70, No. 128 (July 6, 2005): 39165
[4] IBID
[5] IBID
[6] IBID
[7] IBID

should be considered technically feasible and the technological difficulty evaluated as part of the economic analysis[8].

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[9].

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[10], 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.

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[8] IBID

[9] IBID

[10] 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.*[11]

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[12]." 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[13];" 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

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[11] Federal Register 70, No. 128 (July 6, 2005): 39171.
[12] Federal Register 70, No. 128 (July 6, 2005): 39172.
[13] IBID.

BART limit can “instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards[14].”

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

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[14] 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_x, SO_2, and PM. Relative to NO_x and SO_2, 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_2*. 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_x and SO_2 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_x or SO_2. 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_x and SO_2)

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 98th 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 with in the boundaries of each Class I area assessed over the 3-year period 2002-2004.

C. If the modeled emission sources result in a 98th 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 98th percentile change in visibility greater than or equal to 0.05 deciviews, a full BART analysis will be conducted on the emission sources.

Appendix 9I

Tilden Mining Company BART Letter

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Technical Memorandum

To: Asad Khan
From: Teresa Kinder, Barr Engineering
Subject: Tilden Unit 1 BART Recommendation
Date: February 19, 2010
Project: 22/52-0080
c: Brent Ketzenberger, Tom O'Brien, John Flegel, Dave Cartella – Cliffs Natural Resources, Inc.
George Pruchnofski, Barr Engineering

Summary

Michigan Department of Natural Resources and Environment – Air Quality Division (MDNRE) is requesting Cliffs Natural Resources, Inc. (Cliffs) to propose oxides of nitrogen (NOx) and sulfur dioxide (SO_2) limits for Tilden Unit 1 grate/kiln to satisfy Best Available Retrofit Technology (BART) requirements.

As requested by MDNRE, Cliffs proposes the following as BART emission limits for Tilden Unit 1 grate/kiln:

- SO_2 – 28,800 lb SO_2 per calendar day, and
- NOx – Similar to the Minnesota Regional Haze State Implementation Plan, the new NOx limits will be set after testing to determine appropriate limits based on "good combustion practices."

Background

The State of Michigan is required to submit to U.S. EPA a Regional Haze State Implementation Plan (SIP) to make "reasonable progress" to reduce visibility impairment to federal Class I areas. Part of the initial SIP is to include BART determinations to establish emission limits for sources constructed within the time window of 1962 to 1977. BART is only one of many programs that states may rely upon in making "reasonable progress" towards regional haze improvement goals.

MDNRE determined that Tilden Unit 1 is considered BART-eligible. Once a unit is considered BART-eligible, Cliffs is then required to determine if the unit is subject to BART at pre-BART conditions.

Per U.S. EPA guidance, the baseline (or pre-BART conditions), represents the average emission rate in units of pounds per hour (lbs/hr) and reflects the maximum 24-hour actual emissions for each visibility impairing pollutant emitted from the indurating furnace, which in this case are particulate matter (PM), nitrous of oxides (NOx) and sulfur dioxide (SO_2). These emission rates are then modeled to evaluate the potential visibility impact to Class I areas. In order to evaluate the maximum rate for each pollutant as mandated by BART, it required the assumption of 100% natural gas usage for NOx emissions and 100% coal usage for SO_2 emissions. The modeling results show SO_2 emissions do not cause visibility impairment to the Class I areas. Therefore, the BART proposal will primarily focus on NOx emissions.

Proposed BART

The visibility impairment pollutants from indurating furnaces are PM, NOx and SO_2. BART allows application of other standards to regulate a pollutant, such as maximum achievable control technology (MACT). Since the Taconite MACT regulates PM as a surrogate to hazardous air pollutants and Tilden Unit 1grate/kiln is subject to the Taconite MACT, BART applies the applicable PM limits in the Taconite MACT. The PM limit for magnetite is of 0.01 grains per dry standard cubic foot (gr/dscf) and 0.03 gr/dscf for hematite. Therefore, the Taconite PM emission limit is BART.

MDNRE has requested Cliffs to propose an appropriate SO_2 emission limit for the Tilden Unit 1 grate/kiln. As the modeling results from 100% coal usage scenario showed, the SO_2 emissions are not causing or contributing to visibility impairment. Therefore, the current Tilden's Title V permit limits for SO_2 emissions of 28,800 lbs per calendar day are sufficient. Cliffs proposes to continue to limit the SO_2 emissions for Tilden Unit 1 grate/kiln as established in the Tilden Title V permit.

MDNRE has also requested Cliffs to propose an emission limit for NOx. Due to the lack of sufficient emissions data representing good combustion practices and the range of operating conditions that influence emissions, Cliffs is unable at this time to propose an emission limit that corresponds to BART for Tilden Unit 1 grate/kiln. Cliffs proposes to develop a NOx emission factor in pounds of NOx per million BTU of heat input by collecting sufficient emissions data through stack testing to determine appropriate limits based on "good combustion practices." The establishment of the NOx emission factor through stack testing is similar to the requirements in the Minnesota Regional Haze State Implementation Plan for taconite facilities. The established NOx emission factor can then be incorporated into Tilden's Title V renewable operating permit, pursuant to 40 CFR Part 51 Appendix Y.