

REASONABLE PROGRESS FOUR-FACTOR
ANALYSIS
GRAYMONT WESTERN US INC. > Townsend, MT



Prepared By:

Anna Henolson, P.E., C.M. – Managing Consultant
Sam Najmolhoda – Associate Consultant

TRINITY CONSULTANTS
20819 72nd Ave S
Suite 610
Kent, WA 98032
(253) 867-5600

September 2019

Project 194801.0065

Confidential Business Information Excluded

Trinity 
Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1-1
2. INTRODUCTION AND BACKGROUND	2-1
3. SOURCE DESCRIPTION	3-1
4. EXISTING EMISSIONS	4-1
5. SO₂ FOUR FACTOR EVALUATION	5-1
5.1. STEP 1: Identification of Available Retrofit SO₂ Control Technologies	5-1
5.1.1. Inherent Dry Scrubbing	5-2
5.1.2. Alternative Low Sulfur Fuels	5-2
5.1.3. Wet Scrubbing	5-2
5.1.4. Semi-Wet/Dry Scrubbing	5-3
5.2. STEP 2: Eliminate Technically Infeasible SO₂ Control Technologies	5-3
5.2.1. Inherent Dry Scrubbing	5-3
5.2.2. Alternative Low Sulfur Fuels	5-3
5.2.3. Wet Scrubbing	5-3
5.2.4. Semi-Wet/Dry Scrubbing	5-4
5.3. STEP 3: Rank of Technically Feasible SO₂ Control Options by Effectiveness	5-4
5.4. STEP 4: Evaluation of Impacts for Feasible SO₂ Controls	5-5
5.4.1. Cost of Compliance	5-5
5.4.1.1. Control Costs	5-5
5.4.1.2. Annual Tons Reduced	5-5
5.4.1.3. Cost Effectiveness	5-6
5.4.2. Timing for Compliance	5-6
5.4.3. Energy Impacts	5-6
5.4.4. Non-Air Quality Impacts	5-6
5.4.5. Remaining Useful Life	5-7
5.5. SO₂ Conclusion	5-7
6. NO_x FOUR FACTOR EVALUATION	6-8
6.1. STEP 1: Identification of Available Retrofit NO_x Control Technologies	6-8
6.1.1. Combustion Controls	6-9
6.1.1.1. Reduce Peak Flame Zone Temperature	6-9
6.1.1.2. Low NO _x Burners	6-9
6.1.1.3. Preheater Kiln Design/ Proper Combustion Practices	6-9
6.1.2. Post Combustion Controls	6-9
6.1.2.1. Selective Catalytic Reduction	6-9
6.1.2.2. Selective Non-Catalytic Reduction	6-10
6.2. STEP 2: Eliminate Technically Infeasible NO_x Control Technologies	6-11
6.2.1. Combustion Controls	6-11
6.2.1.1. Reduce Peak Flame Zone Temperature	6-11
6.2.1.2. Low NO _x Burners	6-11
6.2.1.3. Preheater Kiln Design/Proper Combustion Practices	6-11
6.2.2. Post Combustion Controls	6-12
6.2.2.1. Selective Catalytic Reduction	6-12
6.2.2.2. Selective Non-Catalytic Reduction	6-13

6.3. STEP 3: Rank of Technically Feasible NO_x Control Options by Effectiveness	6-16
6.4. STEP 4: Evaluation of Impacts for Feasible NO_x Controls	6-17
6.4.1. <i>Cost of Compliance</i>	6-17
6.4.2. <i>Timing for Compliance</i>	6-18
6.4.3. <i>Energy Impacts and Non-Air Quality Impacts.....</i>	6-18
6.4.4. <i>Remaining Useful Life</i>	6-18
6.5. NO_x Conclusion	6-18
7. CONCLUSION	7-1
APPENDIX A : RBLC SEARCH RESULTS	A-1
APPENDIX B : SO₂ CONTROL COST CALCULATIONS	B-1
APPENDIX C : NO_x CONTROL COST CALCULATIONS	C-1

LIST OF FIGURES

Figure 6-1. Preheater – Cross Section	6-13
Figure 6-2. Preheater Stone Chamber Temperature Variation with Time and Location	6-14

LIST OF TABLES

Table 4-1. Annual Baseline Emission Rates	4-1
Table 5-1. Available SO ₂ Control Technologies for Indian Creek Kilns 1 and 2	5-1
Table 5-2. Ranking of SO ₂ Control Technologies by Effectiveness	5-4
Table 5-3. SO ₂ Cost of Compliance Based on Emissions Reduction (Per Kiln)	5-6
Table 6-1. Available NO _x Control Technologies for Indian Creek Kilns 1 and 2	6-8
Table 6-2. Ranking of NO _x Control Technologies by Effectiveness	6-17
Table 6-3. SNCR Cost Calculation Summary	6-17

1. EXECUTIVE SUMMARY

This report documents the results of a four-factor control analysis of the two lime kilns at the Graymont Western US Inc. (Graymont) Indian Creek, Montana lime plant. Both kilns are rotary, preheater type kilns that can produce approximately 500 tons per day of lime, each. This report is provided in response to the Montana Department of Environmental Quality (DEQ) request letter dated April 19, 2019.

Graymont previously submitted a four factor analysis for the first regional haze planning period in response to U.S. EPA's request letter dated November 5, 2010. This analysis serves as an update to the previous analysis, accounting for the latest advances in control technology and costs for completeness.

The U.S. EPA's guidelines in 40 CFR Part 51.308 are used to evaluate control options for the lime kilns. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these four factors are taken into consideration in selecting the goal (40 CFR 51.308(d)(1)(i)(A)).

The purpose of this report is to provide information to DEQ regarding potential SO₂ and NO_x emission reduction options for the Graymont Indian Creek lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Indian Creek lime kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The report identifies the following potential control technologies for the Graymont lime kilns:

SO₂ Emission Reduction Options

- **Semi-Wet/Dry Scrubber:** The analysis assumes that an SO₂ control efficiency of 90% could be achieved with a semi-wet/dry scrubber. However, this is a very aggressive control efficiency level, and it may be difficult to maintain this level of control on a continuous basis. Even at 90% control, the cost of implementation for a semi-wet/dry scrubber would be more than \$8,000 per ton of SO₂ reduction. At this cost, semi-wet/dry scrubbing is not cost effective.
- **Alternative Fuel Scenarios:** Alternative fuels are also considered. Currently the kilns utilize a blend of approximately 70% coal and 30% petroleum coke. Switching to all coal, all diesel, or all natural gas could reduce SO₂ emissions. However, neither natural gas firing nor diesel firing are available reduction options for the Graymont facility. Natural gas is not currently available at this location (the nearest pipeline is over 30 miles away). Graymont is not aware of any kilns that have successfully fired 100% diesel fuel, and there are extraordinary technical barriers associated with implementing an unproven technology. The estimated cost of completely replacing petroleum coke with 100% coal is over \$15,000 per ton of SO₂ reduced, making the emission reduction measure cost ineffective.¹

¹ SO₂ reduction from changing the primary fuel is assumed to fully reduce sulfur by the difference in sulfur levels between the fuel types being compared. The analysis also assumes the same level of inherent scrubbing reduction takes place regardless of fuel. These assumptions result in a reduction efficiency that is conservatively high for the 100% coal reduction method and a cost that is conservatively low.

- **Inherent Dry Scrubbing:** SO₂ is inherently dry scrubbed in a rotary lime kiln, as combustion gasses pass over raw material particulate. The various alkaline components contained in the processed raw materials reduce approximately 90% of the SO₂ that would otherwise leave the stack.
- All other SO₂ reduction options are determined to be technically infeasible at this time.

NO_x Emission Reduction Options

- **SNCR:** Selective non-catalytic reduction (SNCR) has not been implemented on lime kilns in the United States, with the exception of one instance of installation on record. The only entry of SNCR on a lime kiln in the RACT/BACT/LAER Clearinghouse (RBLC) database is for a facility that has not demonstrated successful implementation of SNCR for their cement kiln.² Graymont determined SNCR to be technically infeasible for the Indian Creek facility's lime kiln during the first planning period, and the controls remain technically infeasible. Cost calculations are included for thoroughness, and the technology is not cost effective, at over \$13,000 per ton of pollutant removed.
- **Low-NO_x Burners:** The kilns currently utilize low NO_x burners to minimize NO_x emissions. No other proven control technologies are identified in this evaluation to further reduce NO_x emissions.

Also note that these two lime kilns were both permitted under EPA's PSD program and were determined to meet BACT at the time those permits were issued and the sources constructed. Furthermore, the NO_x and SO₂ controls that the Indian Creek kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.³ Graymont expects that control programs under the current regional haze efforts will not go beyond BACT.

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_x and SO₂ at its Indian Creek facility in Townsend, Montana. There are currently no technically feasible and cost effective reduction options available for the Graymont facility. Therefore, the emissions provided for the 2028 on-the-books/on-the-way modeling baseline are expected to be the same as those used in the "control scenario" for the Graymont Indian Creek facility.

² See Appendix A, the RBLC Search Results, for a list of recent BACT determinations.

³ Ibid.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state⁴. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(i)):

- (A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
- (B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between “natural” and “anthropogenic” sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On April 19, 2019, Montana DEQ sent a letter to Graymont requesting that they assist in “developing information for the reasonable progress analysis” for Graymont’s Indian Creek plant.⁵ Graymont understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Montana. The purpose of this report is to provide information to DEQ regarding potential SO₂ and NO_x emission reduction options for the Graymont Indian Creek lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ’s request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Indian Creek lime kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional

⁴ After initially withdrawing efforts to adopt a state implementation plan (SIP) in 2006, the Montana Department of Environmental Quality operated under a Federal Implementation Plan (FIP) developed by the EPA through 2018. MDEQ is now transitioning back to an SIP for addressing the requirements for regional haze under 40 CFR 51.308.

⁵ Letter from Montana DEQ to Graymont dated April 19, 2019.

Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The information presented in this report considers the following four factors for the emission reductions:

- Factor 1. Costs of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance
- Factor 4. Remaining useful life of the kilns

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines⁶ for conducting a review of Best Available Retrofit Technology (BART) for a unit⁷. These steps are as follows:

- Step 1. Identify all available retrofit control technologies
- Step 2. Eliminate technically infeasible control technologies
- Step 3. Evaluate the control effectiveness of remaining control technologies
- Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for SO₂ and NO_x can be found in Sections 5 and 6 of this report, respectively. Section 4 of this report includes information on the Graymont Indian Creek kilns' existing/baseline emissions.

⁶ The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

⁷References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Graymont Indian Creek facility.

3. SOURCE DESCRIPTION

The Graymont Western US, Inc. Indian Creek Plant is located in Broadwater County near Townsend, Montana, approximately 25 miles southeast of Helena. The nearest Class I area to the plant is the Gates of the Mountains Wilderness Area. It is approximately 35.5 miles northwest of the Indian Creek plant.

The facility operates two horizontal rotary preheater lime kilns. The two kilns are nearly identical in design and operations, although constructed at different times. Kiln #1 was installed in 1982 and Kiln #2 was installed in 1990. Each kiln has a nominal lime production rate of 500 tons per day.

Both kilns can utilize coal and petroleum coke as fuels for the lime production process. Typical annual fuel usage rates for both kilns combined are approximately 40,000 tons per year of coal (at 8,600 Btu/lb) and 20,000 tons per year of coke (at 14,400 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Further details of the fuel throughputs and emission rates are provided in Section 4.

4. EXISTING EMISSIONS

This section summarizes emission rates that are used as baseline rates in the four factor analyses presented in Sections 5, 6, and 7 of this report.

Baseline annual emissions for NO_x and SO₂ are calculated based on stack test data combined with annual production and consistent with annual emission inventory reports. These same baseline rates are provided to DEQ and WRAP for use in the on-the-books/on-the-way basis for modeling because no changes to kiln operation are expected between now and 2028. The baseline annual emission rates are summarized in Table 4-1.

Table 4-1. Annual Baseline Emission Rates

Pollutant	Kilns 1 and 2, Combined (ton/yr)
NO _x	367.80
SO ₂	238.39

5. SO₂ FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

- Step 1. Identify all available retrofit control technologies
- Step 2. Eliminate technically infeasible control technologies
- Step 3. Evaluate the control effectiveness of remaining control technologies
- Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline SO₂ emission rates that are used in the SO₂ four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently have inherent process limestone/lime scrubbing as SO₂ controls which are determined to be BACT at the time of their PSD permit issuance dates and which is also commonly determined as BACT for preheater rotary kilns being permitted today.⁸

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT SO₂ CONTROL TECHNOLOGIES

Sulfur dioxide, SO₂, is generated during fuel combustion in a lime kiln, as the sulfur in the fuel is oxidized by oxygen in the combustion air. Sulfur in the limestone raw material can also contribute to a kiln's SO₂ emissions, though the proportion of sulfur contained in the raw material is much less than that of the fuel.

Step 1 of the top-down control review is to identify available retrofit control options for SO₂. The available SO₂ retrofit control technologies for the Indian Creek kilns are summarized in Table 5-1. The retrofit controls include both add-on controls that eliminate SO₂ after it is formed and switching to lower sulfur fuels which reduces the formation of SO₂.

Table 5-1. Available SO₂ Control Technologies for Indian Creek Kilns 1 and 2

SO₂ Control Technologies
Inherent Dry Scrubbing Alternative Low Sulfur Fuels Wet Scrubbing Semi-Wet/Dry Scrubbing Dry Sorbent Injection

⁸ See Mississippi Lime permit (IL) from December 2010.

5.1.1. Inherent Dry Scrubbing

SO₂ is inherently scrubbed within a lime kiln system due to the presence of large volumes of alkaline materials in the system, including limestone in the preheater that all kiln exhaust gases pass through. A typical kiln system scrubs approximately 90% of SO₂ (originating from both fuel sulfur and raw material sulfur) that would otherwise leave the stack. This in-situ scrubbing mechanism is commonly determined as BACT for preheater rotary kilns being permitted today.⁹ Dry sorbent injection operates under a similar principle, using the injection of lime particulate into the process stream to initiate the same reaction. Dry sorbent injection is not considered an available control methodology, because the reaction is already taking place inherently as part of the lime kiln process.

5.1.2. Alternative Low Sulfur Fuels

Fuels that can be considered for use in the lime kilns must have sufficient heat content, be dependable and readily available locally in significant quantities so as to not disrupt continuous production. Also, they must not adversely affect product quality.

Currently, the Graymont Indian Creek kilns utilize coal and petroleum coke during normal operations. Alternative lower-sulfur fuels that can be considered include natural gas and diesel, as well as an operating scenario using exclusively coal.

In the case of natural gas, there is currently no natural gas supplied to the facility. The nearest natural gas pipeline is on the East side of Helena, Montana, approximately 30 miles from the plant, and there are no plans to run a pipeline towards the area of the plant. Therefore, natural gas is not considered an available alternative control method at this time.

In the case of diesel, there are no examples of kilns that fire 100% diesel fuel for lime production. Therefore, the use of diesel fuel is not a commercially established emission reduction method and is not considered an available, feasible option at this time.

Only the all-coal scenario will be considered going forward.

5.1.3. Wet Scrubbing

A wet scrubber is a tail pipe technology that may be installed downstream of the kilns. In a typical wet scrubber, the flue gas flows upward through a reactor vessel that has an alkaline reagent flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium (or other alkaline reagent) in the reagent reacts with the SO₂ in the flue gas to form calcium sulfite and/or calcium sulfate that is removed with the scrubber sludge and is disposed. Most wet scrubber systems used forced oxidation to assure that only calcium sulfate sludge is produced.

⁹ See BACT determinations at Chemical Lime, Ltd. in Comal, TX, Mississippi Lime Company in Randolph, IL, the Clifton Lime Plant in Bosque, TX, and Graymont's facility in Bayfield, WI in the RBLC search in Appendix A.

5.1.4. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing uses a scrubber tower installed prior to the baghouse. Atomized hydrated lime slurry is sprayed into the exhaust flue gas. The lime absorbs the SO₂ in the exhaust and turns it into a powdered calcium/sulfur compound. The particulate control device removes the solid reaction products from the gas stream.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE SO₂ CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible SO₂ control technologies that were identified in Step 1.

5.2.1. Inherent Dry Scrubbing

Inherent dry scrubbing occurs in the lime kiln systems and is particularly effective in rotary preheater type kilns. Baseline emissions in Section 4 account for this form of SO₂ control. All alternative methods of SO₂ control in this analysis conservatively assume that the kilns maintain the current level of inherent dry scrubbing.

5.2.2. Alternative Low Sulfur Fuels

The use of entirely coal as the primary source of fuel is technically feasible and will be considered further.

5.2.3. Wet Scrubbing

A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO₂ from stack gas. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge.

Graymont estimates that the slurry required per kiln will be approximately 250 gallons per minute (gpm) of water.¹⁰ Approximately 50% of this water can be recovered from dewatering efforts. The remaining 125 gpm per kiln will need to be continuously added to the system. For both kilns, this amounts to 131.4 million gallons per year.

The Indian Creek plant's water rights entitle the plant to use up to 75 million gallons per year. Plant records indicate the facility's current water usage is approximately 5 million gallons per year. Therefore, at most only 70 million gallons are available to the plant for additional needs. Because the facility would need over 131 million gallons per year to operate the wet scrubbers, the facility would need to acquire the rights to more than an additional 61 million gallons of water per year to operate two wet scrubbers and provide for possible other demands by the plant for water. All water rights in that area of Montana have already been appropriated, so the facility does not have the water resources available to operate wet scrubbers at the facility.

¹⁰ Based on Graymont's wet scrubber on 500 ton per day lime kiln at Cricket Mountain, Utah facility.

Wet scrubbing SO₂ control technology is technically infeasible for this facility because the Indian Creek plant does not have adequate water resources to operate wet scrubbers. Therefore, this technology is not considered further.

5.2.4. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing uses considerably less water than wet scrubbing; therefore, it is technically feasible and will be considered further.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE SO₂ CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 5-2 presents potential SO₂ control technologies for the kilns and their associated control efficiencies.

Table 5-2. Ranking of SO₂ Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
SO ₂	Semi-wet/dry Scrubbing	90.0 ^a
	Alternative Low Sulfur Fuel – All Coal	51.8 ^b
	Inherent Dry Scrubbing	Base case ^c

^a Assumes 95% control equipment uptime.

^b The alternative fuel scenario reduction efficiency is calculated using a material balance on the fuel sulfur, with fuel sulfur emissions reductions assumed to be independent of feed sulfur emissions and inherent dry scrubbing.

^c Estimated inherent SO₂ control efficiency is 90%. Additional reductions from alternative control methods are applied to the base case, conservatively assuming that reduction from inherent dry scrubbing is unaffected by the reduction options.

The alternative fuel scenarios have a calculated control efficiency that takes into account two key assumptions:

- Changing the primary fuel will fully reduce sulfur by the difference in sulfur levels between the fuel types being compared, affecting only the emissions directly resulting from sulfur contained in the fuel. SO₂ emitted from sulfur contained in the raw material that is processed in the kilns is assumed to not be affected.
- The control efficiencies assume the same level of in-situ scrubbing reduction takes place under all fuel scenarios. These alternative fuel efficiency values are the incremental control efficiencies that take place as a result of the fuel switching beyond the inherent control.

Given the complexity of the inherent scrubbing's impact on SO₂ resulting from fuel sulfur vs. raw material sulfur, assuming the fuel switching fully reduces sulfur by the difference in sulfur levels between the fuel types is particularly conservative. In reality inherent SO₂ reduction would likely be substantially reduced when the SO₂ concentration in the exhaust stream routed through the pre-heater is reduced.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO₂ CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of semi-wet/dry scrubbing have been estimated by scaling the capital and operating costs used in the first round of regional haze by the Chemical Engineering Plant Cost Index (CEPCI). The alternative all-coal fuel scenario calculations are determined using the fuel costs associated with plant operations during baseline emission years. Currently, the Indian Creek kilns utilize a combination of approximately 70% coal and 30% coke by mass.

5.4.1.1. Control Costs

The capital and operating costs of the semi-wet/dry scrubber used in the cost effectiveness calculations are estimated based on vendor quotes obtained during the first planning period for similar sources, along with published calculations methods. The capital cost is annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized cost. The details of the capital and operating cost estimates are provided in Appendix B of this report.

The cost of the fuel switching used in the cost effectiveness calculations is determined by calculating the current annual cost of using a coal and coke blend and determining the increased cost of switching to all coal, all diesel, and all natural gas. Details are provided in Appendix B.

The Graymont Indian Creek plant currently uses a low heat content coal (Powder River Basin [PRB]) that is obtained locally. In order to bring the kiln system to the required calcination temperature range, Graymont must blend this coal with a higher heat content fuel such as petroleum coke. In considering the all-coal alternative fuel scenario, it would not be technically feasible to use all PRB coal for the analysis. Therefore, Graymont factored in the composition and cost of an appropriate quality coal that would need to be transported to the plant and blended with the PRB coal.

Switching fuel may require changes to the burners and the fuel storage, processing and delivery system. These factors are significant, especially for the all natural gas alternative fuel scenario. For this case, there would be a significant capital cost to establish a line from the nearest pipeline, which is approximately 30 miles from the plant. For this analysis, however, capital expenses are not included. The control cost for each option is summarized in Table 5-3.

5.4.1.2. Annual Tons Reduced

The annual tons reduced that are used in the cost effectiveness calculations are determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. The baseline annual emission rates are summarized in Table 4-1. For a semi-wet/dry scrubber, the controlled annual emission rate is based on the assumed maximum control efficiency noted in Table 5-2. For alternative fuel scenarios, the controlled annual emission rates are estimated by conducting a mass balance on the sulfur in the various fuels relative to the current baseline. The coal and coke sulfur

content is obtained from recent analyses (0.49% and 5.37%, respectively). For diesel, it is assumed that typical sulfur concentrations would remain below 500 parts per million (0.05%). For natural gas, it is assumed that supplies would contain less than 0.2 grains sulfur per 100 standard cubic feet. Details are provided in Appendix B.

An estimate of the amount of SO₂ that may be reduced annually for each of the proposed options is summarized in Table 5-3.

5.4.1.3. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 5-3 summarizes the results.

Table 5-3. SO₂ Cost of Compliance Based on Emissions Reduction

Control Option	Control Cost (\$/yr)	Baseline Emission Level (tons)	SO₂ Reduction^a (%)	Emission Reduction (tons)	Cost Effectiveness (\$/ton removed)
Semi-wet/dry Scrubbing	\$3,939,630	238.39	90.0%	203.82 ^a	\$9,664
Alt. Fuel – All Coal	\$1,887,649	238.39	51.8%	123.45 ^b	\$15,290

^a Assumes a 95% Uptime for the Add-on Control Device

^b Control efficiencies for fuel scenarios are assumed to impact fuel sulfur emissions only. Sulfur contained in the raw material is assumed to be unaffected.

5.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if MDEQ determines that one of the SO₂ control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that the addition of add-on SO₂ controls can be implemented during the period of the second long-term planning period for regional haze (approximately ten years following EPA’s reasonable progress determination).

5.4.3. Energy Impacts

The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix B. To operate any of the add-on control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

5.4.4. Non-Air Quality Impacts

Most of the alternative SO₂ control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A semi-wet/dry hydrated lime control system, for example, will require water to hydrate lime. There will also be additional material collected in the baghouses that will require disposal.

In the Colorado Air Pollution Control Division (APCD) general analysis in the Regional Haze SIP Technical Analyses (April, 2010), the APCD concluded, with regards to SO₂ controls, that wet scrubbing or wet flue gas desulfurization (FGD) has significant negative environmental impacts.¹¹ In the arid West, including Montana, water scarcity is a significant concern—this holds especially true when weighing the benefits of a wet vs. a semi-wet or dry control technology, as wet scrubbing requires a significant quantity of water. In addition, environmental concerns associated with sludge disposal and visible plumes resulted in the APCD’s determination that wet scrubbers did not qualify as BART.

5.4.5. Remaining Useful Life

The remaining useful life of the kilns does not impact the annualized cost of an add-on control technology (semi-wet/dry scrubbing control) because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 20 years. Similarly, the remaining useful life of the kilns does not impact the annualized cost for the various fuel scenarios that are evaluated.

5.5. SO₂ Conclusion

The lime production process inherently removes the majority of SO₂ that is created from the process. This inherent control measure was BACT for these kilns when they were originally constructed and is still commonly BACT for rotary kilns recently permitted under the PSD program.

In this analysis, no available reduction options for SO₂ emissions are identified that are cost effective and technically feasible for the Indian Creek facility.

¹¹ Colorado Air Pollution Control Division (APCD) General Analysis: April 2010 (Regional Haze SIP Technical Analyses), “Regarding Energy and Non Air-Quality Impacts: SO₂ Controls.”

6. NO_x FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

- Step 1. Identify all available retrofit control technologies
- Step 2. Eliminate technically infeasible control technologies
- Step 3. Evaluate the control effectiveness of remaining control technologies
- Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_x emission rates that are used in the NO_x four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently utilize low NO_x burners (LNB), as described in Section 6.1.1.2, below.

6.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_x CONTROL TECHNOLOGIES

NO_x is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms “thermal” NO_x and “fuel” NO_x when describing NO_x emissions from the combustion of fuel. Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_x emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO_x formed within a rotary lime kiln is classified as thermal NO_x. Virtually all of the thermal NO_x is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 degrees Fahrenheit. A small portion of NO_x is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for NO_x. The available NO_x retrofit control technologies for the Indian Creek kilns are summarized in Table 6-1.

Table 6-1. Available NO_x Control Technologies for Indian Creek Kilns 1 and 2

NO_x Control Technologies	
Combustion Controls	Reduce Peak Flame Zone Temperature Low NO _x Burners (LNB) Proper Kiln Operation Preheater Kiln Design
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_x emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the kiln burner, which minimizes NO_x formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NO_x in the flue gas to molecular nitrogen and water.

6.1.1. Combustion Controls

6.1.1.1. Reduce Peak Flame Zone Temperature

These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NO_x. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

6.1.1.2. Low NO_x Burners

LNBS reduce the amount of NO_x initially formed in the flame. The principle of all LNBS is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBS are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NO_x formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO_x and fuel NO_x are minimized¹².

6.1.1.3. Preheater Kiln Design/ Proper Combustion Practices

The use of staged combustion and preheating alone can lead to effective reduction of NO_x emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NO_x.¹³

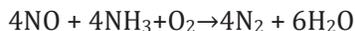
6.1.2. Post Combustion Controls

6.1.2.1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH₃) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH₃ and nitric oxide (NO) or nitrogen dioxide (NO₂) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

¹² USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO_x Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 5-5 to 5-8.

¹³ Ibid, Page 58.



When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.¹⁴ The rate of NO_x removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO_x removal efficiency begins to decrease. As of this report, there are no known instances of SCRs installed on lime kilns.

6.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_x and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_x reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_x through a similar chemical reaction.



SNCR residence time can vary between 0.001 seconds and 10 seconds.¹⁵ However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO_x removal. There is a slight gain in performance for residence times greater than 0.5 seconds. The EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,550°F and 1,950°F,¹⁶ due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. That said, the effectiveness of SNCR on lime kilns is largely unproven. Lime kilns present unique technical challenges not experienced by cement kilns. While mid-kiln injection is often the most effective method of implementing SNCR on cement kilns, injection at that location is not feasible for a lime kiln. Lime kilns experience lower NO_x concentrations at a given point in the kiln, have shorter residence times, and face issues in the stability of temperature profiles when compared to cement kilns. At higher temperatures, NO_x reduction is less effective.¹⁷ In addition, a greater residence time is required when operating at lower temperatures.

In cement kilns SNCR can be applied as a tailpipe technology or in a certain combustion zone of kilns to facilitate SNCR in a non-tailpipe mode (mid-kiln SNCR). However, there are important differences between and lime kiln and cement kiln that cause technical barriers to mid-kiln firing. The lime industry has a

¹⁴ Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_x Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

¹⁵ Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NO_x Controls, EPA/452/B-02-001, Page 1-8

¹⁶ Ibid, Page 1-6

¹⁷ USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO_x Emissions from Cement Manufacturing. EPA-453/R-94-004, Section 5.2.2, Page 5-21.

severely limited track record in determining the feasibility or control level that could be attained if mid-kiln SNCR were attempted on the Indian Creek kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NO_x concentrations distinguishing lime production from the cement production process. A search of the RACT/BACT/LAER Clearinghouse (RBLC) database indicates that there is only one instance of a lime kiln that was permitted with SNCR as control for NO_x emissions.¹⁸ The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that takes into account the control of NO_x emissions achieved by the SNCR (unless it is demonstrated to not provide effective control or result in unacceptable consequences). Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the one instance of known SNCR installation on a different lime kiln (which does not appear in RBLC results), very limited information is available on the details of this kiln necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Indian Creek. Therefore, SNCR has not been demonstrated as a successful control option for NO_x emissions from lime kilns.

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_x CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_x control technologies that were identified in Step 1.

6.2.1. Combustion Controls

6.2.1.1. Reduce Peak Flame Zone Temperature

In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NO_x formation, they also inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are technically infeasible.

6.2.1.2. Low NO_x Burners

The facility currently operates Pillard low- NO_x burners in the lime kilns. Coal and coke are delivered to the burners using a direct fired system. However, to limit NO_x, only enough primary air is used to sweep coal and coke out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels.

Baseline emissions are based on the operation of these low NO_x burners. All alternative methods of NO_x control in this analysis will assume that the kilns continue to operate these burners.

6.2.1.3. Preheater Kiln Design/Proper Combustion Practices

Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

¹⁸ RBLC Search results are provided in 7.Appendix A, see the entry for the Mississippi Lime Company.

6.2.2. Post Combustion Controls

6.2.2.1. Selective Catalytic Reduction

Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually $\pm 200^\circ\text{F}$).¹⁹ Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NO_x emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH_3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NO_x and are emitted in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F . The source of heat for the heat exchanger would be the combustion of fuel²⁰, with combustion products that would enter the process gas stream and generate additional NO_x . Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NO_x control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone.

The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.²¹

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, tail pipe, high dust and semi-dust SCR's are considered technically infeasible at this time.

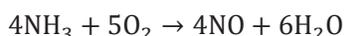
¹⁹ Ibid, Page 2-11

²⁰ The fuel would likely be propane or diesel. There is no natural gas at the facility, and coal would require an additional dust collector.

²¹ Preamble to NSPS subpart F, 75 FR 54970.

6.2.2.2. Selective Non-Catalytic Reduction

At temperatures above 2,100°F, NO_x generation starts to occur as shown in the reaction below:

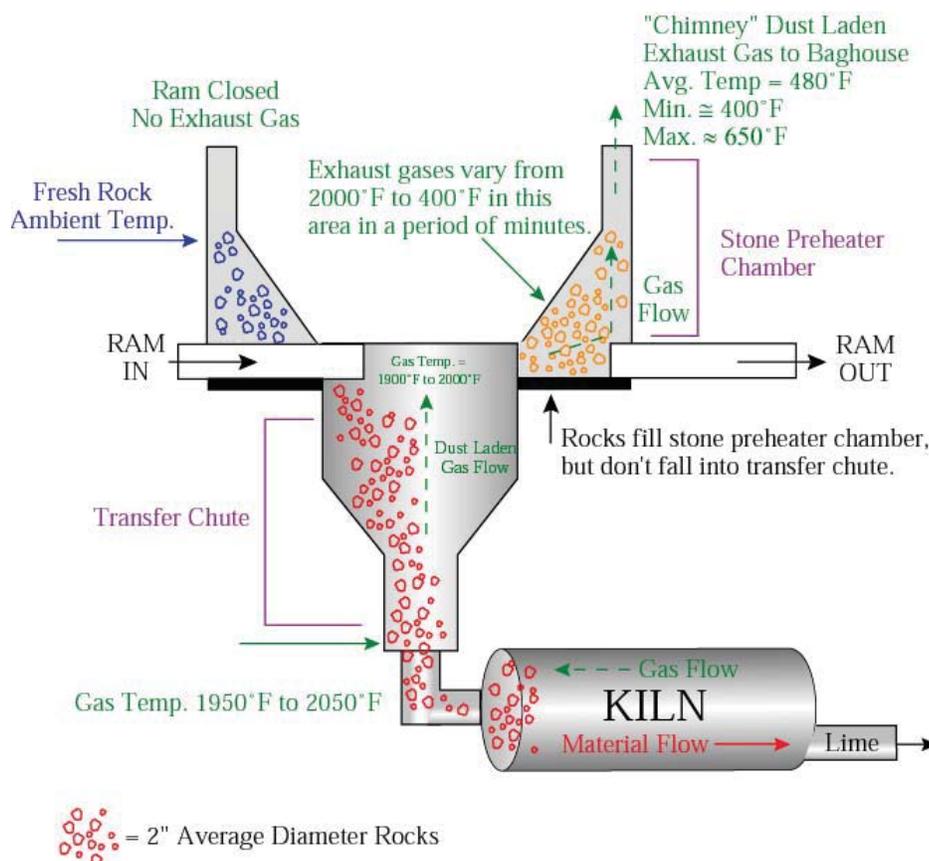


This reaction causes ammonia to oxidize and form NO instead of removing NO. When temperatures exceed 2200°F, NO formation dominates. This would likely be the case if ammonia were directly injected into the kiln tube. At temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip.

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

Figure 6-1 provides a schematic of a preheater/kiln system including typical process temperatures in the system.

Figure 6-1. Preheater – Cross Section



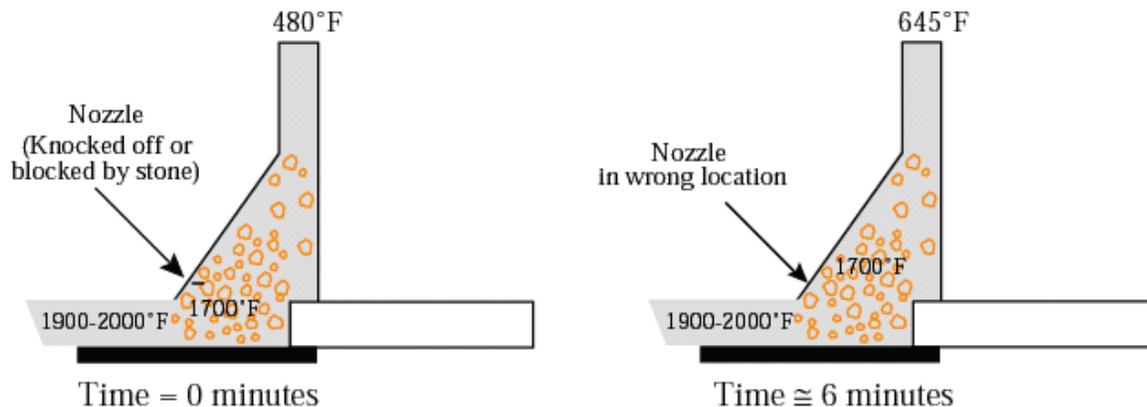
*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Indian Creek facility

SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater

The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

In each Graymont Indian Creek preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the “in” position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again. The temperature profile in the stone chamber varies as shown in Figure 6-2.

Figure 6-2. Preheater Stone Chamber Temperature Variation with Time and Location



*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Indian Creek facility

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not

be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible²².

SNCR Ammonia/Urea Injection Location – Transfer Chute

As shown in Figure 6-1, the temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper bound for the NO_x reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NO_x reduction in clean (non dust-laden) exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone²³. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NO_x controlled. Given the significant range (35-58%) of control efficiencies found for cement kilns, a control efficiency considerably lower than the average for cement of 40% is expected given ideal temperature scenarios (many kilns in the cement industry that utilize SNCR do so in the combustion zone in the calciner, where temperatures are lower than in the kiln). Lime kilns experience significant technical barriers to successful SNCR implementation not shared by the cement industry. When compared to the cement process, lower NO_x concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. Therefore, a control efficiency of no more than 20% is anticipated for the Indian Creek kilns.

Locating an ammonia or urea injector nozzle in the chute to ensure mixing of the ammonia with the combustion gases would pose similar problems as the problems with the stone chamber location. Stones pour into the chute from the stone chamber, and in order to stabilize a nozzle for injection, the nozzle would need to be positioned out of the direct path of the flow of the stones. Further, the stone pieces that pour into the transfer chute from the chamber take up a large portion of the volume in the chute. Adequate mixing of the ammonia or urea with the combustion gases would be inhibited by the rock. The ammonia or urea would most likely end up on the stones, rather than mixing evenly throughout the gas stream.

The low percent NO_x reduction combined with the uncertainty of the nozzle placement and mixing requirement eliminate the transfer chute as a technically feasible option for Indian Creek Kilns 1 and 2.

SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln

Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

Graymont is aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NO_x reduction. However, the technology costs and technical

²² Report Concerning BACT for SO₂ and NO_x for Proposed Lime Kiln,” prepared for Air Pollution Control Division, Clark County Health District, Las Vegas, Nevada, April 1995.

²³ EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-7.
<https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf>

details have not become publically available, so Graymont cannot evaluate if the technology can be successfully applied specifically to the kilns at the Indian Creek facility.

Since a mid-kiln ammonia injection and transfer chute ammonia/urea injection systems would require pilot scale testing, Graymont must conclude that this type of SNCR is not “available” with respect to the Indian Creek plant because it is not commercially available. Since it is not commercially available, no vendor performance guarantees can be made to its success. Therefore, this technology cannot be considered technically feasible.

The technology is not commercially available, as defined in 40 CFR Subpart 51, Appendix Y which states that:

Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” As explained in more detail below, a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

The typical stages for bringing a control technology concept to reality as a commercial product are:

- *Concept stage;*
- *Research and patenting;*
- *Bench scale or laboratory testing;*
- *Pilot scale testing;*
- *Licensing and commercial demonstration; and*
- *Commercial sales.*

A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as “available” for purposes of BART review.

Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or “applicable” to the source type under consideration.

Though the technology is not considered technically feasible for Graymont’s Indian Creek facility, cost calculations for the implementation of SNCR are included for completeness.

6.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 6-2 presents potential NOx control technologies for the kilns and their associated control efficiencies.

Table 6-2. Ranking of NO_x Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO _x	SNCR Low NO _x Burner	20* Base case

* 20% control efficiency is used for cost evaluation based on evaluation of feasibility of SNCR at another Graymont facility.

6.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_x CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1. Cost of Compliance

In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 5.5% for interest calculations, per MDEQ and EPA guidance. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air pre-heater will require modifications for coal-fired units when SO₂ control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation²⁴, and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the annuitized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described in section 6.2.2.1, including only one known SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NO_x concentrations that limit the effectiveness of the control technology. The total costs and cost effectiveness of control are summarized in Table 6-3, below.

Table 6-3. SNCR Cost Calculation Summary

Total Capital Investment	Total Annual Cost	NO_x Emissions Removed (tpy)	Cost Effectiveness (\$/ton removed)
\$8,603,378	\$879,163	66	\$13,303

²⁴ EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-44.
<https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf>

6.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if MDEQ determines SNCR is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the second planning period of regional haze (approximately ten years following EPA's reasonable progress determination).

6.4.3. Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix C. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

6.4.4. Remaining Useful Life

Graymont has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

6.5. NO_x CONCLUSION

The facility currently uses low NO_x burners in its two kilns to minimize NO_x emissions. The use of low NO_x burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one documented instance of successful implementation on a lime kiln. The use of these controls do not represent a cost effective control technology given the limited expected improvements to NO_x emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NO_x removed.

7. CONCLUSION

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_x and SO₂ at its Indian Creek facility in Townsend, Montana. There are currently no technically feasible and cost effective reduction options available for the Graymont facility. Therefore, the emissions provided for the 2028 on-the-books/on-the-way modeling baseline are expected to be the same as those used in the "control scenario" for the Graymont Indian Creek facility.

APPENDIX A : RBLC SEARCH RESULTS

Table A-1. RBL Search Results

RBL ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVERAGE TIME CONDITION
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Nitrogen Oxides (NOx)	Low excess air to minimize formation of NOx and selective non-catalytic reduction (SNCR) technology.	3.5	LBS/TON LIME PRODUCE	30-DAY ROLLING AVERAGE	2.61	LBS/TON LIME PRODUCE	12-MONTH ROLLING AVERAGE
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Nitrogen Oxides (NOx)		5	LB/TON OF LIME PROD		0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Nitrogen Oxides (NOx)		2.6	LB/TON OF LIME PROD		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Nitrogen Oxides (NOx)	GOOD COMBUSTION CONTROL, OPTIMIZATION	1.83	LB/T	24 HOUR AVG.	0.7	LB/MMBTU	MONTHLY AVG.
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Sulfur Dioxide (SO2)	Natural absorptive capacity of lime kiln dust.	0.5	LBS/TON LIME	30-DAY ROLLING AVERAGE	0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0820	CLIFTON LIME PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	4/28/2017	lime kiln	coal	219000	t/yr	Sulfur Dioxide (SO2)	fuel sulfur limits	12.8	LB/TON LIME		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT, INHERENT PROCESS COLLECTION OF SULFUR OXIDES.	0.62	LB/T	24 HOUR AVERAGE	2	PERCENT S	FUEL SULFUR LIMIT

APPENDIX B : SO₂ CONTROL COST CALCULATIONS

CONFIDENTIAL BUSINESS INFORMATION

Graymont Indian Creek Kilns - Cost of SO₂ Reductions from Alternative Fuel Scenarios

Fuel Scenario	Fuel	Annual Consumption	Consumption Units	Fuel Cost (\$/unit)	Annual Fuel Cost	Annual Fuel Cost Increase	Total Annual Fuel SO ₂ Emissions (ton)	Total Annual SO ₂ Reduction (ton)	Total Cost of SO ₂ Reduction (\$/ton reduced)
Base	Coal Coke Total	Confidential Business Information	tons tons	Confidential Business Information		\$ -	221.8	-	\$ -
All Coal	PRB Coal Normal BTU Coal for Coke Total		tons tons			\$ 1,917,165	98.4	123.45	\$ 15,530

Graymont Indian Creek Kilns - SO₂ Emissions from Alternative Fuel Scenarios (Kiln 1 and Kiln 2 Combined)

Current Scenario

Fuels	Maximum Combined Fuel Usage ^a ton/yr	Heat Content Btu/lb	Annual Fuel Heat Usage Btu/yr	Sulfur Content	Potential Sulfur Emissions ton/yr	Potential SO ₂ Emissions ton/yr	Inherent Scrubbing Efficiency	Maximum Projected SO ₂ Emissions ton/yr
PRB Coal	CBI	8,826	CBI		252	505	90%	50.5
Coke		14,409			857	1,714	90%	171.4
Total					1,109	2,218		221.8

^a Total fuel usage is determined using the average fuel throughput to the kiln, with the ratio assumed to be equivalent to the ratio of coal and coke unloaded at the facility.
Average Fuel Unloaded (2016-2018)

Coal: CBI tons
Coke: CBI tons

Substitute Coal for Coke (Use all Coal)

Fuels	Usage ton/yr	Heat Content ^a Btu/lb	Annual Fuel Heat Usage Btu/yr	S Content ^b	Potential S Emissions ton/yr	Potential SO ₂ Emissions ton/yr	Inherent Scrubbing Efficiency	SO ₂ Emissions ton/yr
PRB Coal	CBI	8,826	CBI		252	505	90%	50.46
Normal BTU Coal for Coke		11,841			240	479	90%	47.91
Total					492	984		98.37

^a EPA default values for sub-bituminous and bituminous coal, respectively.

^b Estimated based on available coal analyses.

Scenario	Total SO ₂ Emissions ton/yr	Reduction vs Baseline %
Baseline (Coal & Coke)	221.82	0.00%
All Coal	98.37	55.7%

Scenario	Total SO ₂ Emissions ton/yr	Reported Baseline Emissions ton/yr	Non-Fuel Emission Rate ton/yr	Adjusted Emission Rate ton/yr	Reduction vs Baseline, Adjusted %
Baseline (Coal & Coke)	221.82	238.39	16.57	238.39	0.0%
All Coal	98.37	238.39	16.57	114.94	51.8%

**Estimated Cost of Semi-Dry Scrubber
Graymont Indian Creek**

Direct Costs		Notes
Purchased Equipment Costs		(\$5,775,000 from Turbosonic system Quote 2010 for 69,000 acfm @ 300°F, scaled according to 0.6 power rule) B CONTROL COST MANUAL - EPA/452/B-02-001 (CCM), Section 5.1, Chapter 1, Table 1.3 CCM, Section 5.1, Chapter 1, Table 1.3
Scrubber Unit	\$5,310,474	
Instrumentation (10% of EC)	incl	
Sales Tax (3% of EC)	incl	
Freight (5% of EC)	incl	
Subtotal, Purchased Equipment Cost (PEC)	\$5,310,474	
Direct Installation Costs		
Foundation (6% of PEC)	Incl	
Supports (6% of PEC)	Incl	
Handling and Erection (40% of PEC)	Incl	
Electrical (1% of PEC)	Incl	
Piping (30% of PEC)	Incl	
Insulation for Ductwork (1% of PEC)	Incl	
Painting (1% of PEC)	Incl	
Turnkey Installation	\$1,931,081	
Site Preparation	N/A	No data
Buildings	N/A	No data
Total Direct Cost	\$7,241,555	
Indirect Costs		
Engineering (10% of PEC)	\$531,047	
Construction and Field Expense (10% of PEC)	\$531,047	
Contractor Fees (10% of PEC)	\$531,047	
Start-up (1% of PEC)	\$53,105	
Performance Test (1% of PEC)	\$53,105	
Contingencies (3% of PEC)	\$159,314	
Total Indirect Cost	\$1,858,666	
Total Capital Investment (TCI) (2010 \$)	\$9,100,221	
Direct Annual Costs		
Hours per Year (330 days per year, 24 hours per day)	8,040	
Operating Labor		
Man-hrs	3,840	Based on Turbosonic system
Rate	\$50	Based on Turbosonic system
Subtotal, Operating Labor	\$192,000	
Maintenance		
Maintenance	\$200,000	Based on Turbosonic system
Subtotal, Maintenance	\$200,000	
Utilities		
Electricity		
Demand (kW)	40.84	Based on Turbosonic system - 377,600 kw-hr
Cost (\$/kW-hr)	\$0.0700	Based on Turbosonic system - assumed \$0.07/kW-hr
Subtotal, Electricity	\$22,984	
Hydrated Lime		
Amount Required (ton/yr)	129	Based on Turbosonic system (scaled from modeled max SO ₂ content of 760 lb/hr to 62.1 lb/hr)
Cost (\$/ton)	\$110.00	Based on Turbosonic system (profit lost to Graymont)
Subtotal, Lime	\$14,201	
Process Water		
Amount Required (gal/yr)	1,812	Based on Turbosonic system (to hydrate lime). (Scaled from modeled max SO ₂ content of 760 lb/hr to 62.1 lb/hr).
Cost (\$/ton)	\$0.20	Based on Turbosonic system
Subtotal, Lime	\$362	
Subtotal, Utilities	\$37,548	
Total Direct Annual Costs (2010 \$)	\$429,548	
Indirect Annual Costs		
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)	\$243,938	
Administrative (2% TCI)	\$182,004	0.02 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Property Tax (1% TCI)	\$91,002	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Insurance (1% TCI)	\$91,002	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Capital Recovery (20 year life, 5.5 percent interest)	\$761,500	CCM, Sec 1, Ch 2, Eqn 2.8a
Total Indirect Annual Cost (2010 \$)	\$1,369,447	
Total Annualized Cost (2018 \$)	\$1,969,815	2011 Estimate scaled by CEPCI, from 2010 \$ (year of the quote) to 2018 \$ (most recently published year for index).
Pollutant Emission Rate Prior to Scrubber (tons SO ₂ /yr)	238.4	
Pollutant Removed (tons SO ₂ /yr) 90% removal per vendor	203.8	Assumes 95% control equipment uptime
Cost Per Ton of Pollutant Removed	\$9,664	
Total Annualized Cost for both Kilns	\$3,939,630	

APPENDIX C : NO_x CONTROL COST CALCULATIONS

Cost Estimate

Graymont Indian Creek Kiln 1

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,133,785 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$656,360 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,462,865 in 2018 dollars
Total Capital Investment (TCI) =	\$4,228,913 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEV \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEV \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,133,785 in 2018 dollars
--	-----------------------------

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$656,360 in 2018 dollars
---	---------------------------

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,462,865 in 2018 dollars
---	-----------------------------

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$76,066 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$355,863 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$431,929 in 2018 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$63,434 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$11,123 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$529 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$238 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$662 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$80 in 2018 dollars
Direct Annual Cost =		\$76,066 in 2018 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,903 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$353,960 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$355,863 in 2018 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$431,929 per year in 2018 dollars
NOx Removed =	31 tons/year
Cost Effectiveness =	\$13,967 per ton of NOx removed in 2018 dollars

Cost Estimate

Graymont Indian Creek Kiln 2

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,156,847 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$681,369 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,526,757 in 2018 dollars
Total Capital Investment (TCI) =	\$4,374,465 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEV \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEV \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEV \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,156,847 in 2018 dollars
--	-----------------------------

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$681,369 in 2018 dollars
---	---------------------------

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,526,757 in 2018 dollars
---	-----------------------------

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$79,122 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$368,111 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$447,233 in 2018 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$65,617 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$11,891 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$566 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$254 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$708 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$86 in 2018 dollars
Direct Annual Cost =		\$79,122 in 2018 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,969 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$366,143 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$368,111 in 2018 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$447,233 per year in 2018 dollars
NOx Removed =	35 tons/year
Cost Effectiveness =	\$12,718 per ton of NOx removed in 2018 dollars