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

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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 SO\textsubscript{2} and NO\textsubscript{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:

**SO\textsubscript{2} Emission Reduction Options**

- **Semi-Wet/Dry Scrubber**: The analysis assumes that an SO\textsubscript{2} 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 SO\textsubscript{2} 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 SO\textsubscript{2} 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 SO\textsubscript{2} reduced, making the emission reduction measure cost ineffective.\(^1\)

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\(^1\) SO\textsubscript{2} 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: SO\textsubscript{2} 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 SO\textsubscript{2} that would otherwise leave the stack.

All other SO\textsubscript{2} reduction options are determined to be technically infeasible at this time.

**NO\textsubscript{X} Emission Reduction Options**

- **SNCR:** Selective non-cata\textsubscript{lytic} 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.\textsuperscript{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\textsubscript{X} Burners:** The kilns currently utilize low NO\textsubscript{X} burners to minimize NO\textsubscript{X} emissions. No other proven control technologies are identified in this evaluation to further reduce NO\textsubscript{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\textsubscript{X} and SO\textsubscript{2} controls that the Indian Creek kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.\textsuperscript{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\textsubscript{X} and SO\textsubscript{2} 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.

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

\textsuperscript{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 remediating 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 state. 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. 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 NOₓ 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

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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 guidelines\(^6\) for conducting a review of Best Available Retrofit Technology (BART) for a unit\(^7\). 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 SO\(_2\) 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.

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

\(^7\)References 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\textsubscript{X} and SO\textsubscript{2} 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

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Kilns 1 and 2, Combined (ton/yr)</th>
</tr>
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<tbody>
<tr>
<td>NO\textsubscript{X}</td>
<td>367.80</td>
</tr>
<tr>
<td>SO\textsubscript{2}</td>
<td>238.39</td>
</tr>
</tbody>
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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 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.

### 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>
<thead>
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<th>Table 5-1. Available SO₂ Control Technologies for Indian Creek Kilns 1 and 2</th>
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<tr>
<td><strong>SO₂ Control Technologies</strong></td>
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<tr>
<td>Alternative Low Sulfur Fuels</td>
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<tr>
<td>Wet Scrubbing</td>
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<tr>
<td>Semi-Wet/Dry Scrubbing</td>
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<tr>
<td>Dry Sorbent Injection</td>
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</tbody>
</table>

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8See Mississippi Lime permit (IL) from December 2010.
5.1.1. Inherent Dry Scrubbing

SO\textsubscript{2} 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 SO\textsubscript{2} (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.\textsuperscript{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 SO\textsubscript{2} 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.

\textsuperscript{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>
<thead>
<tr>
<th>Pollutant</th>
<th>Control Technology</th>
<th>Potential Control Efficiency (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂</td>
<td>Semi-wet/dry Scrubbing</td>
<td>90.0 a</td>
</tr>
<tr>
<td></td>
<td>Alternative Low Sulfur Fuel – All Coal</td>
<td>51.8 b</td>
</tr>
<tr>
<td></td>
<td>Inherent Dry Scrubbing</td>
<td>Base case c</td>
</tr>
</tbody>
</table>

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 SO\textsubscript{2} 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. SO\textsubscript{2} Cost of Compliance Based on Emissions Reduction**

<table>
<thead>
<tr>
<th>Control Option</th>
<th>Control Cost ($/yr)</th>
<th>Baseline Emission Level (tons)</th>
<th>SO\textsubscript{2} Reduction\textsuperscript{a} (%)</th>
<th>Emission Reduction (tons)</th>
<th>Cost Effectiveness ($/ton removed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Semi-wet/dry Scrubbing</td>
<td>$3,939,630</td>
<td>238.39</td>
<td>90.0%</td>
<td>203.82\textsuperscript{a}</td>
<td>$9,664</td>
</tr>
<tr>
<td>Alt. Fuel – All Coal</td>
<td>$1,887,649</td>
<td>238.39</td>
<td>51.8%</td>
<td>123.45\textsuperscript{b}</td>
<td>$15,290</td>
</tr>
</tbody>
</table>

\textsuperscript{a} Assumes a 95% Uptime for the Add-on Control Device
\textsuperscript{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 SO\textsubscript{2} control options analyzed in this report is necessary to achieve reasonable progress, it is anticipated that the addition of add-on SO\textsubscript{2} 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 SO\textsubscript{2} 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.

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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:

1. Identify all available retrofit control technologies
2. Eliminate technically infeasible control technologies
3. Evaluate the control effectiveness of remaining control technologies
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 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\textsubscript{X} emission rates that are used in the NO\textsubscript{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\textsubscript{X} burners (LNB), as described in Section 6.1.1.2, below.

### 6.1. Step 1: Identification of Available Retrofit NO\textsubscript{X} Control Technologies

NO\textsubscript{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\textsubscript{X} and "fuel" NO\textsubscript{X} when describing NO\textsubscript{X} emissions from the combustion of fuel. Thermal NO\textsubscript{X} emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO\textsubscript{X} emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO\textsubscript{X} formed within a rotary lime kiln is classified as thermal NO\textsubscript{X}. Virtually all of the thermal NO\textsubscript{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\textsubscript{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\textsubscript{X}. The available NO\textsubscript{X} retrofit control technologies for the Indian Creek kilns are summarized in Table 6-1.

#### Table 6-1. Available NO\textsubscript{X} Control Technologies for Indian Creek Kilns 1 and 2

<table>
<thead>
<tr>
<th>NO\textsubscript{X} Control Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Combustion Controls</strong></td>
</tr>
<tr>
<td>Reduce Peak Flame Zone Temperature</td>
</tr>
<tr>
<td>Low NO\textsubscript{X} Burners (LNB)</td>
</tr>
<tr>
<td>Proper Kiln Operation</td>
</tr>
<tr>
<td>Preheater Kiln Design</td>
</tr>
<tr>
<td><strong>Post-Combustion Controls</strong></td>
</tr>
<tr>
<td>Selective Catalytic Reduction (SCR)</td>
</tr>
<tr>
<td>Selective Non-Catalytic Reduction (SNCR)</td>
</tr>
</tbody>
</table>
NOx 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 NOx formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) convert NOx 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 NOx. 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 NOx Burners

LNBs reduce the amount of NOx 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 NOx 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 NOx and fuel NOx are minimized.

6.1.1.3. Preheater Kiln Design/ Proper Combustion Practices

The use of staged combustion and preheating alone can lead to effective reduction of NOx 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 NOx.

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:

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13 Ibid, Page 58.
4NO + 4NH₃+O₂→4N₂ + 6H₂O

2NO₂+4NH₃+O₂→3N₂+6H₂O

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. The rate of NOₓ 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 NOₓ removal efficiency begins to decrease. As of this report, there are no known instances of SCR systems 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 NOₓ 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 NOₓ reductions.

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

\[ 2\text{NO} + 4\text{NH}_3 + 2\text{O}_2 \rightarrow 3\text{N}_2 + 6\text{H}_2\text{O} \]

SNCR residence time can vary between 0.001 seconds and 10 seconds. However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NOₓ 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, 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 NOₓ 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, NOₓ reduction is less effective. 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

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14 Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOₓ 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, NOₓ Controls, EPA/452/B-02-001, Page 1-8
16 ibid, Page 1-6
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 NOx 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 NOx emissions. 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 NOx 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 NOx emissions from lime kilns.

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NOx CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NOx 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 NOx 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 NOx Burners

The facility currently operates Pillard low-NOx burners in the lime kilns. Coal and coke are delivered to the burners using a direct fired system. However, to limit NOx, 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 NOx burners. All alternative methods of NOx 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.

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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 ± 200°F). 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 NOx emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH3 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 NOX and are emitted in a detached plume) and increased SO3 emissions (from oxidation of SO2 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 fuel, with combustion products that would enter the process gas stream and generate additional NOx. 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 NOx 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.

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.

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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\textsubscript{X} generation starts to occur as shown in the reaction below:

\[ 4\text{NH}_3 + 5\text{O}_2 \rightarrow 4\text{NO} + 6\text{H}_2\text{O} \]

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.

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**Figure 6-1. Preheater – Cross Section**

- **Ram Closed**
  - No Exhaust Gas
- **Fresh Rock**
  - Ambient Temp.
- **Gas Temp.**
  - 1950°F to 2050°F
- **Exhaust gases vary from 2000°F to 400°F in this area in a period of minutes**
- **Rocks fill stone preheater chamber, but don’t fall into transfer chute.**

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**Image Description:**

- **“Chimney” Dust Laden Exhaust Gas to Baghouse**
  - Avg. Temp = 480°F
  - Min. = 400°F
  - Max. = 650°F
- **Gas Flow**
- **Material Flow**
- **Lime**
- **2” Average Diameter Rocks**
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 infeasible

**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 NOx reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NOx 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 cone. 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 NOx 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 NOx 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 NOx 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 NOx reduction. However, the technology costs and technical

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

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\textsubscript{x} Control Technologies by Effectiveness

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Control Technology</th>
<th>Potential Control Efficiency (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO\textsubscript{x}</td>
<td>SNCR</td>
<td>20*</td>
</tr>
<tr>
<td></td>
<td>Low NO\textsubscript{x} Burner</td>
<td>Base case</td>
</tr>
</tbody>
</table>

* 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\textsubscript{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 SO\textsubscript{2} control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation\textsuperscript{24}, 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\textsubscript{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

<table>
<thead>
<tr>
<th>Total Capital Investment</th>
<th>Total Annual Cost</th>
<th>NO\textsubscript{x} Emissions Removed (tpy)</th>
<th>Cost Effectiveness ($/ton removed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$8,603,378</td>
<td>$879,163</td>
<td>66</td>
<td>$13,303</td>
</tr>
</tbody>
</table>

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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. NOₓ CONCLUSION

The facility currently uses low NOₓ burners in its two kilns to minimize NOₓ emissions. The use of low NOₓ 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 NOₓ emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NOₓ removed.
7. CONCLUSION

This report outlines Graymont’s evaluation of possible options for reducing the emissions of NOx 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.
<table>
<thead>
<tr>
<th>RBLC ID</th>
<th>FACILITY NAME</th>
<th>CORPORATE OR COMPANY NAME</th>
<th>FACILITY STATE</th>
<th>PERMIT ISSUANCE DATE</th>
<th>PROCESS NAME</th>
<th>PRIMARY FUEL</th>
<th>THROUGHPUT THROUGHPUT UNIT</th>
<th>POLLUTANT CONTROL METHOD DESCRIPTION</th>
<th>EMISSION LIMIT 1</th>
<th>EMISSION LIMIT 1 AVERAGE TIME CONDITION</th>
<th>EMISSION LIMIT 2</th>
<th>EMISSION LIMIT 2 AVERAGE TIME CONDITION</th>
</tr>
</thead>
<tbody>
<tr>
<td>IL-8117</td>
<td>MISSISSIPPI LIME COMPANY</td>
<td>MISSISSIPPI LIME COMPANY</td>
<td>IL</td>
<td>9/29/2010</td>
<td>Two Rotary Kilns</td>
<td>Coal, petroleum coke</td>
<td>50 ton lime/heat, each</td>
<td>Nitrogen Oxides (NOx) Low-NOx burners, limestone injection</td>
<td>3.5 LB/TON LIME PRODUCE</td>
<td>24-HOUR AVERAGE</td>
<td>2.61 LB/TON LIME PRODUCE</td>
<td>24-MONTH ROLLING AVERAGE</td>
</tr>
<tr>
<td>TX-0726</td>
<td>ROTARY LIME KILN AND ASSOCIATED EQUIPMENT</td>
<td>CHEMICAL LIME, LTD</td>
<td>TX</td>
<td>2/2/2010</td>
<td>Rotary Kiln 2</td>
<td>Natural gas, coal, and petroleum coke</td>
<td>594 ton per day</td>
<td>Nitrogen Oxides (NOx) Low-NOx burners, limestone injection</td>
<td>5 LB/TON LIME PRODUCE</td>
<td>0</td>
<td>2.6 LB/TON LIME PRODUCE</td>
<td>0</td>
</tr>
<tr>
<td>TX-0726</td>
<td>ROTARY LIME KILN AND ASSOCIATED EQUIPMENT</td>
<td>CHEMICAL LIME, LTD</td>
<td>TX</td>
<td>2/2/2010</td>
<td>Rotary Kiln 3</td>
<td>Natural gas, coal, and petroleum coke</td>
<td>856 ton per day</td>
<td>Nitrogen Oxides (NOx) Low-NOx burners, limestone injection</td>
<td>2.6 LB/TON LIME PRODUCE</td>
<td>0</td>
<td>0 LB/TON LIME PRODUCE</td>
<td>0</td>
</tr>
<tr>
<td>WA-0250</td>
<td>GRAYMINT (W) LLC</td>
<td>GRAYMINT (W) LLC</td>
<td>WA</td>
<td>2/6/2009</td>
<td>PS1 (196) PRESSURE EQUIPPED, ROTARY LIME KILN</td>
<td>Coal</td>
<td>54 T/STOKE</td>
<td>Nitrogen Oxides (NOx) GOOD COMBUSTION CONTROL, OPTIMIZATION</td>
<td>3.83 LB/T</td>
<td>24 HOUR AVERAGE</td>
<td>0.7 LB/NM3STU</td>
<td>MONTHLY AVERAGE</td>
</tr>
<tr>
<td>IL-8117</td>
<td>MISSISSIPPI LIME COMPANY</td>
<td>MISSISSIPPI LIME COMPANY</td>
<td>IL</td>
<td>9/29/2010</td>
<td>Two Rotary Kilns</td>
<td>Coal, petroleum coke</td>
<td>50 ton lime/heat, each</td>
<td>Sulfur Dioxide (SO2) Natural absorption capacity of lime-kepa dust</td>
<td>0.5 LB/TON LIME</td>
<td>24-HOUR ROLLING AVERAGE</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TX-0726</td>
<td>ROTARY LIME KILN AND ASSOCIATED EQUIPMENT</td>
<td>CHEMICAL LIME, LTD</td>
<td>TX</td>
<td>2/2/2010</td>
<td>Rotary Kiln 2</td>
<td>Natural gas, coal, and petroleum coke</td>
<td>594 ton per day</td>
<td>Sulfur Dioxide (SO2) Low-NOx burners, limestone injection</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TX-0726</td>
<td>ROTARY LIME KILN AND ASSOCIATED EQUIPMENT</td>
<td>CHEMICAL LIME, LTD</td>
<td>TX</td>
<td>2/2/2010</td>
<td>Rotary Kiln 3</td>
<td>Natural gas, coal, and petroleum coke</td>
<td>856 ton per day</td>
<td>Sulfur Dioxide (SO2) Low-NOx burners, limestone injection</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TX-0820</td>
<td>CLIFTON LIME PLANT</td>
<td>LEFTT NORTH AMERICA OF TEXAS, LTD</td>
<td>TX</td>
<td>6/28/2017</td>
<td>Lime kilns</td>
<td>Coal</td>
<td>239000 T/yr</td>
<td>Sulfur Dioxide (SO2) Combustion control, scrubbing the fuel-sulfur oxides in addition to the dry scrubbing inherent in these systems</td>
<td>12.0 LB/TON LIME</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>WA-0250</td>
<td>GRAYMINT (W) LLC</td>
<td>GRAYMINT (W) LLC</td>
<td>WA</td>
<td>2/6/2009</td>
<td>PS1 (196) PRESSURE EQUIPPED, ROTARY LIME KILN</td>
<td>Coal</td>
<td>54 T/STOKE</td>
<td>Sulfur Dioxide (SO2) FULL SOLIDURE LIMIT, EXISTING PROCESS COLLECTION OF SULPHUR OXIDES</td>
<td>0.62 LB/T</td>
<td>24 HOUR AVERAGE</td>
<td>2</td>
<td>PERCENT S FUEL SULPHUR LIMIT</td>
</tr>
</tbody>
</table>
APPENDIX B : SO$_2$ CONTROL COST CALCULATIONS

---

Graymont Western US Inc. | Indian Creek Plant Four Factor Analysis
Trinity Consultants

B-1
## CONFIDENTIAL BUSINESS INFORMATION

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

<table>
<thead>
<tr>
<th>Fuel Scenario</th>
<th>Fuel</th>
<th>Annual Consumption</th>
<th>Consumption Units</th>
<th>Fuel Cost ($/unit)</th>
<th>Annual Fuel Cost</th>
<th>Annual Fuel Cost Increase</th>
<th>Total Annual Fuel SO₂ Emissions (ton)</th>
<th>Total Annual SO₂ Reduction (ton)</th>
<th>Total Cost of SO₂ Reduction ($/ton reduced)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Coal Coke</td>
<td>Confidential Business Information</td>
<td>tons tons</td>
<td>Confidential Business Information</td>
<td>$ -</td>
<td>221.8</td>
<td>-</td>
<td>-</td>
<td>$ -</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All Coal</td>
<td>PRB Coal</td>
<td>Confidential Business Information</td>
<td>tons tons</td>
<td>Confidential Business Information</td>
<td>$ 1,917,165</td>
<td>98.4</td>
<td>123.45</td>
<td>$ 15,530</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Normal BTU Coal for Coke</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Graymont Indian Creek Kilns - SO₂ Emissions from Alternative Fuel Scenarios (Kiln 1 and Kiln 2 Combined)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PRB Coal</td>
<td>8,820</td>
<td>14.4%</td>
<td></td>
<td></td>
<td>252</td>
<td>505</td>
<td>90%</td>
<td>50.5</td>
</tr>
<tr>
<td>Coke</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>857</td>
<td>1,714</td>
<td>90%</td>
<td>171.4</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,109</td>
<td>2,218</td>
<td>90%</td>
<td>221.9</td>
</tr>
</tbody>
</table>

¹ 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.

Coal: CBI tons

Coke: CBI tons

Substitute Coal for Coke (Use all Coal)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PRB Coal</td>
<td>8,820</td>
<td></td>
<td></td>
<td></td>
<td>252</td>
<td>505</td>
<td>90%</td>
<td>50.44</td>
</tr>
<tr>
<td>Normal FTU Coal</td>
<td>11,841</td>
<td></td>
<td></td>
<td></td>
<td>240</td>
<td>479</td>
<td>90%</td>
<td>47.91</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>492</td>
<td>984</td>
<td>90%</td>
<td>98.32</td>
</tr>
</tbody>
</table>

² EPA default values for sub-bituminous and bituminous coal, respectively.

³ Estimated based on available coal analyses.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total SO₂ Emissions (ton/yr)</th>
<th>Reduction vs Baseline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline (Coal &amp; Coke)</td>
<td>221.82</td>
<td>0.00%</td>
</tr>
<tr>
<td>All Coal</td>
<td>98.37</td>
<td>55.7%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Total SO₂ Emissions (ton/yr)</th>
<th>Reported Baseline Emissions Rate (ton/yr)</th>
<th>Non-Fuel Emission Rate (ton/yr)</th>
<th>Adjusted Emission Rate (ton/yr)</th>
<th>Reduction vs Baseline, Adjusted (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline (Coal &amp; Coke)</td>
<td>221.82</td>
<td>238.39</td>
<td>16.57</td>
<td>238.39</td>
<td>0.0%</td>
</tr>
<tr>
<td>All Coal</td>
<td>98.37</td>
<td>238.39</td>
<td>16.57</td>
<td>114.94</td>
<td>51.8%</td>
</tr>
</tbody>
</table>
## Estimated Cost of Semi-Dry Scrubber

**Graymont Indian Creek**

### Direct Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2018 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubber Unit</td>
<td>$5,310,474</td>
</tr>
<tr>
<td>Instrumentation (10% of EC)</td>
<td>incl</td>
</tr>
<tr>
<td>Sales Tax (3% of EC)</td>
<td>incl</td>
</tr>
<tr>
<td>Freight (5% of EC)</td>
<td>incl</td>
</tr>
<tr>
<td><strong>Subtotal, Purchased Equipment Cost (PEC)</strong></td>
<td>$5,310,474</td>
</tr>
</tbody>
</table>

#### Direct Installation Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2018 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foundation (0% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Supports (0% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Handling and Erection (40% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Electrical (1% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Piping (30% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Insulation for Ductwork (1% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td>Painting (1% of PEC)</td>
<td>incl</td>
</tr>
<tr>
<td><strong>Turnkey Installation</strong></td>
<td>$1,931,081</td>
</tr>
<tr>
<td>Site Preparation</td>
<td>N/A</td>
</tr>
<tr>
<td>Buildings</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Total Direct Cost:** $7,241,555

### Indirect Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2018 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering (10% of PEC)</td>
<td>$531,047</td>
</tr>
<tr>
<td>Construction and Field Expense (10% of PEC)</td>
<td>$531,047</td>
</tr>
<tr>
<td>Contractor Fees (10% of PEC)</td>
<td>$531,047</td>
</tr>
<tr>
<td>Start-up (1% of PEC)</td>
<td>$33,105</td>
</tr>
<tr>
<td>Performance Test (1% of PEC)</td>
<td>$33,105</td>
</tr>
<tr>
<td>Contingencies (3% of PEC)</td>
<td>$159,314</td>
</tr>
</tbody>
</table>

**Total Indirect Cost:** $1,858,666

**Total Capital Investment (TCI) (2018 $):** $9,100,221

### Direct Annual Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2018 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Labor</td>
<td>$122,000</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$200,000</td>
</tr>
<tr>
<td>Utilities</td>
<td>$37,548</td>
</tr>
</tbody>
</table>

**Total Direct Annual Costs (2018 $):** $429,548

### Indirect Annual Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost (2018 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead (100% of sum of operating, supervising, maintenance labor &amp; materials)</td>
<td>$243,938</td>
</tr>
<tr>
<td>Administrative (2% TCI)</td>
<td>$182,004</td>
</tr>
<tr>
<td>Property Tax (1% TCI)</td>
<td>$91,092</td>
</tr>
<tr>
<td>Insurance (1% TCI)</td>
<td>$91,092</td>
</tr>
<tr>
<td>Capital Recovery (20 year life, 3.5 percent interest)</td>
<td>$761,500</td>
</tr>
</tbody>
</table>

**Total Indirect Annual Cost (2018 $):** $1,324,417

**Total Annualized Cost (2018 $):** $3,909,630

**Notes:**
- $5,775,000 from Turbosonic system Quote 2010 for 69,000 acft @ 300°F, scaled according to 0.4 power rule.
- 2011 Estimate scaled by CEPCL, from 2010 $ (year of the quote) to 2018 $ (most recently published year for index).
- Assumes 95% control equipment uptime.
## Cost Estimate

### Graymont Indian Creek Kiln 1

**Total Capital Investment (TCI)**

For Coal-Fired Boilers:

\[ TCI = 1.3 \times (\text{SNCR} \text{ cost} + \text{APH} \text{ cost} + \text{BOP} \text{ cost}) \]

For Fuel Oil and Natural Gas-Fired Boilers:

\[ TCI = 1.3 \times (\text{SNCR} \text{ cost} + \text{BOP} \text{ cost}) \]

| Capital costs for the SNCR (SNCR\text{cost}) | $1,133,785 in 2018 dollars |
| Air Pre-Heater Costs (APH\text{cost})* | $656,360 in 2018 dollars |
| Balance of Plant Costs (BOP\text{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\text{cost})

For Coal-Fired Utility Boilers:

\[ \text{SNCR cost} = 220,000 \times (B_{\text{MW}} \times \text{HRF})^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF} \]

For Fuel Oil and Natural Gas-Fired Utility Boilers:

\[ \text{SNCR cost} = 147,000 \times (B_{\text{MW}} \times \text{HRF})^{0.42} \times \text{ELEV} \times \text{RF} \]

For Coal-Fired Industrial Boilers:

\[ \text{SNCR cost} = 220,000 \times (0.1 \times Q_{\text{b}} \times \text{HRF})^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF} \]

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

\[ \text{SNCR cost} = 147,000 \times ((Q_{\text{b}}/\text{NPHR}) \times \text{HRF})^{0.42} \times \text{ELEV} \times \text{RF} \]

### Air Pre-Heater Costs (APH\text{cost})*

For Coal-Fired Utility Boilers:

\[ \text{APH cost} = 69,000 \times (B_{\text{MW}} \times \text{HRF} \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF} \]

For Coal-Fired Industrial Boilers:

\[ \text{APH cost} = 69,000 \times (0.1 \times Q_{\text{b}} \times \text{HRF} \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF} \]

### Balance of Plant Costs (BOP\text{cost})

For Coal-Fired Utility Boilers:

\[ \text{BOP cost} = 320,000 \times (B_{\text{MW}})^{0.33} \times (\text{NOx Removed/ hr})^{0.12} \times \text{BTF} \times \text{RF} \]

For Fuel Oil and Natural Gas-Fired Utility Boilers:

\[ \text{BOP cost} = 213,000 \times (B_{\text{MW}})^{0.33} \times (\text{NOx Removed/ hr})^{0.12} \times \text{RF} \]

For Coal-Fired Industrial Boilers:

\[ \text{BOP cost} = 320,000 \times (0.1 \times Q_{\text{b}})^{0.33} \times (\text{NOx Removed/ hr})^{0.52} \times \text{BTF} \times \text{RF} \]

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

\[ \text{BOP cost} = 213,000 \times (Q_{\text{b}}/\text{NPHR})^{0.33} \times (\text{NOx Removed/ hr})^{0.12} \times \text{RF} \]

### Balance of Plant Costs (BOP\text{cost})

$1,462,865 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.
### Annual Costs

<table>
<thead>
<tr>
<th>Total Annual Cost (TAC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TAC = Direct Annual Costs + Indirect Annual Costs</td>
</tr>
</tbody>
</table>

| 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)

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Formula</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Maintenance Cost</td>
<td>(0.015 \times TCI)</td>
<td>$63,434 in 2018 dollars</td>
</tr>
<tr>
<td>Annual Reagent Cost</td>
<td>(q_{\text{act}} \times \text{Cost}<em>{\text{reag}} \times t</em>{\text{op}})</td>
<td>$11,123 in 2018 dollars</td>
</tr>
<tr>
<td>Annual Electricity Cost</td>
<td>(P \times \text{Cost}<em>{\text{elec}} \times t</em>{\text{op}})</td>
<td>$529 in 2018 dollars</td>
</tr>
<tr>
<td>Annual Water Cost</td>
<td>(q_{\text{water}} \times \text{Cost}<em>{\text{water}} \times t</em>{\text{op}})</td>
<td>$238 in 2018 dollars</td>
</tr>
<tr>
<td>Additional Fuel Cost</td>
<td>(\Delta \text{Fuel} \times \text{Cost}<em>{\text{fuel}} \times t</em>{\text{op}})</td>
<td>$662 in 2018 dollars</td>
</tr>
<tr>
<td>Additional Ash Cost</td>
<td>(\Delta \text{Ash} \times \text{Cost}<em>{\text{ash}} \times t</em>{\text{op}} \times (1/2000))</td>
<td>$80 in 2018 dollars</td>
</tr>
<tr>
<td>Direct Annual Cost =</td>
<td></td>
<td>$76,066 in 2018 dollars</td>
</tr>
</tbody>
</table>

### Indirect Annual Cost (IDAC)

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Formula</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Administrative Charges (AC) =</td>
<td>(0.03 \times \text{Annual Maintenance Cost})</td>
<td>$1,903 in 2018 dollars</td>
</tr>
<tr>
<td>Capital Recovery Costs (CR) =</td>
<td>(\text{CRF} \times TCI)</td>
<td>$353,960 in 2018 dollars</td>
</tr>
<tr>
<td>Indirect Annual Cost (IDAC) =</td>
<td>(\text{AC} + \text{CR})</td>
<td>$355,863 in 2018 dollars</td>
</tr>
</tbody>
</table>

### Cost Effectiveness

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Annual Cost (TAC) =</td>
<td>$431,929 per year in 2018 dollars</td>
</tr>
<tr>
<td>NOx Removed =</td>
<td>31 tons/year</td>
</tr>
<tr>
<td>Cost Effectiveness =</td>
<td>$13,967 per ton of NOx removed in 2018 dollars</td>
</tr>
</tbody>
</table>
Cost Estimate

Graymont Indian Creek Kiln 2

Total Capital Investment (TCI)

<table>
<thead>
<tr>
<th>Description</th>
<th>Equation</th>
<th>2018 Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>For Coal-Fired Boilers:</td>
<td>( TCI = 1.3 \times (\text{SNCR} \text{cost} + \text{APH} \text{cost} + \text{BOP} \text{cost}) )</td>
<td></td>
</tr>
<tr>
<td>For Fuel Oil and Natural Gas-Fired Boilers:</td>
<td>( TCI = 1.3 \times (\text{SNCR} \text{cost} + \text{BOP} \text{cost}) )</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
<th>2018 Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital costs for the SNCR (\text{SNCR} \text{cost})</td>
<td>\text{SNCR} \text{cost} = 220,000 \times (B_{\text{MW}} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEVF} \times \text{RF}</td>
<td>$1,156,847</td>
</tr>
<tr>
<td>Air Pre-Heater Costs (\text{APH} \text{cost})*</td>
<td>\text{APH} \text{cost} = 69,000 \times (B_{\text{MW}} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}</td>
<td>$681,369</td>
</tr>
<tr>
<td>Balance of Plant Costs (\text{BOP} \text{cost})</td>
<td>\text{BOP} \text{cost} = 320,000 \times (B_{\text{MW}})^{0.33} \times (\text{NOx}\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}</td>
<td>$1,526,757</td>
</tr>
</tbody>
</table>

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

### Total Annual Cost (TAC)

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Annual Costs (DAC)</td>
<td>$79,122 in 2018 dollars</td>
</tr>
<tr>
<td>Indirect Annual Costs (IDAC)</td>
<td>$368,111 in 2018 dollars</td>
</tr>
<tr>
<td>Total annual costs (TAC) = DAC + IDAC</td>
<td>$447,233 in 2018 dollars</td>
</tr>
</tbody>
</table>

### Direct Annual Costs (DAC)


<table>
<thead>
<tr>
<th>Description</th>
<th>Formula</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Maintenance Cost</td>
<td>$0.015 \times TCI = x_{\text{tm}} \times t_{\text{op}} = $65,617 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Annual Reagent Cost</td>
<td>$q_{\text{reag}} \times \text{Cost}<em>{\text{reag}} \times t</em>{\text{op}} = $11,891 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Annual Electricity Cost</td>
<td>$P \times \text{Cost}<em>{\text{elec}} \times t</em>{\text{op}} = $566 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Annual Water Cost</td>
<td>$q_{\text{water}} \times \text{Cost}<em>{\text{water}} \times t</em>{\text{op}} = $254 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Additional Fuel Cost</td>
<td>$\Delta \text{Fuel} \times \text{Cost}<em>{\text{fuel}} \times t</em>{\text{op}} = $708 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Additional Ash Cost</td>
<td>$\Delta \text{Ash} \times \text{Cost}<em>{\text{ash}} \times t</em>{\text{op}} \times (1/2000) = $86 in 2018 dollars</td>
<td></td>
</tr>
</tbody>
</table>

Direct Annual Cost = $79,122 in 2018 dollars

### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Formula</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Administrative Charges (AC) =</td>
<td>$0.03 \times \text{Annual Maintenance Cost} = $1,969 in 2018 dollars</td>
<td></td>
</tr>
<tr>
<td>Capital Recovery Costs (CR) =</td>
<td>$\text{CRF} \times TCI = $366,143 in 2018 dollars</td>
<td></td>
</tr>
</tbody>
</table>

Indirect Annual Cost (IDAC) = $368,111 in 2018 dollars

## Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Annual Cost (TAC) =</td>
<td>$447,233 per year in 2018 dollars</td>
</tr>
<tr>
<td>NOx Removed =</td>
<td>35 tons/year</td>
</tr>
<tr>
<td>Cost Effectiveness =</td>
<td>$12,718 per ton of NOx removed in 2018 dollars</td>
</tr>
</tbody>
</table>