ENVIROPLAN CONSULTING

Final BART Determination Report
Golden Valley Electric Association (GVEA)
Best Available Retrofit Technology (BART) Evaluation

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

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EXECUTIVE SUMMARY

In accordance with 18 AAC 50.260(j), the Alaska Department of Environmental Conservation (the Department) undertook a review of the Best Available Retrofit Technology (BART) control analysis submitted under 18 AAC 50.260(e)-(h) by Golden Valley Electric Association (GVEA) for the Healy Unit 1 power plant. The BART control analysis was prepared by GVEA for the Healy Power Plant pursuant to the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260. Pursuant to 40 CFR 51, Appendix A, a BART engineering analysis requires the use of six statutory factors for any BART-eligible source that is found to cause or contribute to atmospheric visibility impairment in any of 156 federal parks and wilderness areas protected under the regional haze rule (i.e., mandatory Class I areas).

The Department contracted Enviroplan Consulting to conduct a review and provide a findings report for guidance for machining a BART determination. Enviroplan was to determine whether the analysis conformed to the WRAP modeling protocol and the related rules and regulatory guidance, including: 18 AAC 50.260(e) - (h); Guidelines for best available retrofit technology under the regional haze rule; 40 CFR 51, Appendix Y; Guidelines for BART Determinations Under the Regional Haze Rule; and U.S. EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA-454/B-03-005, September 2003). The review also accounted for comments through the Public Notice process.

The objective of the review, the initial Findings Report, and this BART Determination Report (Final Report) is to document Enviroplan's findings and recommendations regarding GVEA's BART control analysis. Enviroplan initially conducted a review of the July 28, 2008, BART control analysis to determine compliance with 18 AAC 50.260(e)-(h). In response to requests from the Department and Enviroplan, GVEA submitted supplemental information on October 3, 2008; November 11, 2008; and December 10, 2008. GVEA revised and resubmitted the July 2008 report on January 2, 2009. GVEA provided additional relevant supplemental information on March 18, 24, and 30, 2009. Enviroplan prepared a findings report containing a proposed preliminary BART determination for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j). The April 27, 2009 findings report concluded that the GVEA BART control analysis complied with 18 AAC 50.260(e)-(h).

In the April 2009 Findings Report, Enviroplan proposed, and the Department approved, a preliminary BART determination for Healy 1 as the existing dry sorbent injection system (SO_2); the addition of a SCR system (NO_x); and the existing reverse gas baghouse system (PM_{10}). For Auxiliary Boiler #1, the existing configuration (i.e., no air pollution control systems) was determined to be BART.

The Department public noticed the April 2009 Findings Report and proposed BART determination for the Healy plant on May 12, 2009. The 35-day public comment period occurred from May 12, 2009 through June 15, 2009. Comments received were addressed in a Response to Comment (RTC) document. In response to comments, the April 27 Findings Report was revised and adjusted. The revised report is called the Final GVEA BART Determination Report (Final Report). This Final Report, which was issued by the Department to GVEA under a February 9, 2010 cover letter, provides the recommended final BART determination for the Healy plant pursuant to 18 AAC 50.260(l), taking into account as necessary the comments and additional information received during the comment period. This Final Report also takes into account certain decisions made by the Department regarding an informal review request submitted by GVEA on February 24, 2010. The Department's decision on the entirety of GVEA's request has been issued under a separate letter dated April 12, 2010; however, this Final Report is revised to correct deficiencies in the January 19, 2010 Final Report identified by GVEA in their request.

Similar to the April 2009 Findings Report, the purpose of the Final Report is to document Enviroplan's findings regarding GVEA's BART control analysis in terms of compliance with 18 AAC 50.260(e)-(h); and recommend a final BART determination pursuant to 18 AAC 50.260(l), including required pollutant specific emission limits for affected emission units. This Final Report concludes that the GVEA BART control analysis complies with 18 AAC 50.260(e)-(h). For Healy Unit 1, Enviroplan recommends final BART determination emission limits as follows:

BART Emission Limits

The final BART emission limits recommended for Healy Unit 1 are summarized in the table below. The BART emission limits are based on an 8-year remaining useful life for Healy 1 (from calendar year 2016) which is provided for at Section IV.D.4.K of 40 CFR 51, Appendix Y (federal BART rule). The emission limits are compared to current permitted pollutant emission limits which remain in effect.

Table E-1: Final BART Emission Limits Recommended for the GVEA Healy Power Station

	Particulate		**SO_2**		**NOx**	
	Current [1]	BART [2]	Current [1]	BART [2]	Current [1]	BART [2]
Healy Unit 1	0.05 gr/dscf 36.7 lb/hr (hourly average at full load) 161 ton/yr	0.015 lb/MMBtu (based on compliance source testing)	258 lb/hr (24-hour average, calendar day) 367 lb/hr (3-hour average) 472 ton/yr	0.30 lb/MMBtu (30-day rolling average) [3]	429 ton/yr	0.20 lb/MMBtu (30-day rolling average)
Auxiliary Boiler #1	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average 1 ton per calendar year	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average	0.3% S in oil, annual average 0.5% S in oil, 3-hour average	0.53 lb/MMBtu (30-day rolling average)	20 lb NOx/1000 gal distillate fuel, annual average 20% load factor, annual average	0.15 lb/MMBtu (30-day rolling average).

1. Taken from Permit No. 173TVP01, Table 2.
2. BART emission limits for Unit 1 are in addition to the current (existing) emission limits. The BART emission limit for particulate reflects filterable PM_{10}.

The existing uncontrolled configuration for Auxiliary Boiler #1 is considered as final BART since the predicted daily visibility impacts for this unit are well below the significant visibility impairment metric of 0.5 daily deciviews. There is no change in the final BART determination for

Auxiliary Boiler #1 (i.e., no controls; current TV permit emission limitations including equivalent limitations in units of lb/MMBtu). Details on the final BART determination for Healy 1 are presented in Section 8.

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1. INTRODUCTION

1.1 General Program Background

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The rule is codified at 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y. The Regional Haze Rule requires certain States, including Alaska, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary BART-eligible source that might cause or contribute to impairment of visibility in a Class I Area. BART-eligible sources include those sources that:

1. have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
2. were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
3. whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301.

During 2007 the Department developed a list of Alaska BART-eligible sources based on the federal BART guidelines. GVEA's power plant in Healy, Alaska has been identified by the Department as required to conduct BART assessments for its BART-eligible emission units, Healy Unit 1 and Auxiliary Boiler #1. The affected visibility impairing pollutants (VIP) are NO_x, SO_2 and particulate matter (conservatively as PM_{10}). The requirements applicable to Alaska BART-eligible sources were published by the Department on December 30, 2007 under 18 ACC 50.260. The Department's BART regulation requires sources not exempt from applicability based on a visibility modeling analysis to submit a case-by-case BART proposal for each BART-eligible unit at the facility and for each VIP by July 28, 2008.

A preliminary regional BART screening modeling analysis of all BART-eligible sources in Alaska was completed in 2007 by the Western Regional Air Partnership (WRAP) - Regional Modeling Center (RMC). The simulations were done using the CALPUFF modeling system and a single year, 2002, of processed MM5 CALMET data. The simulations were performed to evaluate predicted impacts of visibility in Alaska PSD Class I areas, including the Denali National Park and Preserve (DNPP) and Tuxedni Wilderness Area. BART-eligible sources are exempt from BART if the daily visible impacts at a Class I area are below the screening criteria set by the Department (ADEC), EPA, and the Federal Land Managers (FLMs). Pursuant to 18 AAC 50.260(q)(4), a 0.5 or greater daily deciview change when compared against natural conditions is considered to "cause" visibility impairment.

The initial modeling analysis conducted by WRAP - RMC indicated that the maximum visibility impact of GVEA's facility at the DNPP Class I area was higher than the 0.5 daily deciview visibility screening threshold, while the impacts at Tuxedni were below this threshold. The Department notified GVEA in December 2007 that they were subject to the BART control analysis requirements for the affected equipment since the WRAP – RMC analysis was unsuccessful at providing a basis for exemption. The Department identified the DNPP as the affected Class I area.

GVEA submitted the requisite BART control analysis and preliminary determinations on July 28, 2008. GVEA provided supplemental information on October 3, 2008, November 11, 2008 and December 10, 2008, in response to the Department's contractor, Enviroplan's, September 19, 2008 and October 16, 2008 requests for clarification. After further discussions with the Department and Enviroplan, GVEA submitted a revised BART analysis report on January 2, 2009. Enviroplan reviewed this information and prepared a draft findings report on January 27, 2009. Teleconferences then occurred between the Department, GVEA, CH2M Hill (GVEA's consultant) and Enviroplan on February 25 and 27, 2009 and March 2, 2009. As a follow-up to these teleconferences, GVEA submitted additional supplemental study information on March 18, 24 and 30, 2009.

Pursuant to 40 CFR 51, Appendix A, a BART engineering analysis requires the use of six statutory factors for any BART-eligible source that is found to cause or contribute to atmospheric visibility impairment in any of 156 federal parks and wilderness areas protected under the regional haze rule (i.e., mandatory Class I areas). These factors include: 1) the available retrofit options, 2) any pollution control equipment in use at the source (which affects the availability of options and their impacts), 3) the costs of compliance with control options, 4) the remaining useful life of the facility, 5) the energy and non-air quality environmental impacts of control options, and 6) the visibility impacts analysis.

GVEA conducted the BART control analysis utilizing the above referenced factors. The GVEA analysis concluded that the BART-eligible sources at the Healy Power Plant do not require additional retrofit controls because the potentially feasible control options are either not cost effective, the control options do not result in significant visibility benefit, and/or the cost of visibility improvement resulting from potentially installing these control options are highly cost prohibitive. GVEA considers the existing controls and operating practices on BART-eligible sources at the facility as BART.

The Department contracted Enviroplan Consulting to review the aforementioned GVEA preliminary BART determination to determine whether the analysis conformed to the WRAP modeling protocol and the related rules and regulatory guidance, including: 18 AAC 50.260(e) - (h); Guidelines for best available retrofit technology under the regional haze rule; 40 CFR 51, Appendix Y; Guidelines for BART Determinations Under the Regional Haze Rule; and U.S. EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA-454/B-03-005, September 2003). The review also accounted for comments provided by the National Park Service (NPS) in response to a Department-NPS teleconference of February 10, 2009, wherein preliminary BART control recommendations (from Enviroplan's January 27, 2009 draft findings report) were discussed. The NPS provided the Department with initial comments on February 10, 2009 (verbal) and February 12, 2009 (written as an email). The review also considered all supplemental information provided by GVEA through the end of March 2009.

Enviroplan prepared a BART review Findings Report that was submitted to the Department on April 27, 2009. The report included a recommendation of *proposed* BART controls and related SO_2, NO_x and PM_{10} emission limits for Healy Unit 1. The Department agreed with the Findings Report conclusions and public noticed the BART proposal 35 day comment period from May 12, 2009 though June 15, 2009.

The Department received comments on the proposed BART determination and requested that Enviroplan review each comment and prepare a separate Draft Response to Comments (RTC) document. The RTC document, which specifies the commenter; each of their comments; and detailed responses to the comments, including any changes to data, information and/or conclusions found in April 27, 2009 Findings Report, has been submitted by Enviroplan to the Department.

Based on the above, Enviroplan has incorporated the changes described in the RTC in this version of the findings report, which is now labeled as the "BART Determination Report." The following sections of this document present the revised and final review findings, which includes information from the April 27, 2009 Findings Report as applicable, as well as any updated information submitted to the Department during the comment period that clarifies or alters the conclusions of the April 27, 2009 Findings Report. However, detailed discussions associated with such changes are relegated to the RTC document, and are only summarized as necessary herein. This Final Report also corrects for certain deficiencies and errors identified by GVEA in their February 24, 2010 informal review request, and approved for correction by the Department under a separate letter dated April 12, 2010.

1.2 Source (BART eligible units) Description and Background

Healy 1 is a nominal 25-MW unit located in Healy, Alaska, approximately 8 kilometers (5 miles) from DNPP. The unit is a wall-fired, wet bottom boiler manufactured by Foster Wheeler. Low NO_x burners (LNB) and over-fired air (OFA) ports were installed in 1996. Particulate emissions are collected by a reverse gas baghouse installed in the early 1970s. Sulfur oxides are controlled by a dry sorbent injection system installed in 1999. At the present time sodium bicarbonate is the sorbent which is injected into the flue gas after the air heater.

Comments received from GVEA on June 15, 2009 in response to the proposed BART public notice period (May 12, 2009 - June 15, 2009) included a clarification that the Healy 1 expected "*remaining useful life*", as this term is defined in the regional haze rule and the BART Guideline (i.e., 40 CFR 51, Appendix Y), is about 15 years. GVEA also indicated the useful lifetime of Healy 1 to be 55 years.

Auxiliary Boiler #1 is only used to supply heat to the Healy 1 building during shutdown periods or during emergency repairs to Healy 1. Auxiliary Boiler #1 also provides steam for water processing and hot potable water to the Healy Clean Coal Project (HCCP) if called for during periods when Healy 1 is not operating. The unit is also fired monthly for maintenance checks.

2. ELEMENTS OF THE BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

On July 1, 1999 (40 CFR Part 51), EPA published the Regional Haze Rule which provides the regulations to improve visibility in 156 national parks, wilderness areas, and international parks which were in existence in 1977. One of the key elements of the Regional Haze rule addresses the installation of BART for certain source categories that were built and in operation between 1962 and 1977. BART is defined as:

> *"an emissions limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emissions limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*

BART, also referred to as the "Clean Air Visibility Rule" (CAVR), requires states to identify "BART-eligible" sources. Sources need to meet all three criteria to be considered "BART-eligible" including:

1. The source belongs to one of the 26 listed source categories; these categories are same as those for Prevention of Significant Deterioration (PSD) applicability analysis;
2. The source was installed (constructed) and in operation between 1962 and 1977; and
3. The source emits more than 250 tons per year of any one or all of the visibility impairing pollutants including sulfur dioxide (SO_2), nitrogen oxide (NO_2), or particulate matter (PM_{10}). Volatile organic compounds (VOC) and ammonia (NH_3) may be included depending on the state in which the source is located.

The Alaska BART rule (18 AAC 50.260(f)) requires BART analysis to be conducted for NO_x, SO_2, and PM_{10} only (i.e., visibility impairing pollutants). The BART analysis identifies the best system of continuous emission reduction taking into account:

1. The available retrofit control options,
2. Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
3. The costs of compliance with control options
4. The remaining useful life of the facility,
5. The energy and non-air quality environmental impacts of control options, and
6. The visibility impacts analysis.

The five basic steps of Case-by-Case BART Analysis are:

STEP 1—Identify All Available Retrofit Control Technologies.

In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.

STEP 2—Eliminate Technically Infeasible Options.

Technologies demonstrated to be infeasible based on chemical, physical, and engineering principles are excluded from further consideration.

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

STEP 4—Evaluate Impacts and Document the Results, and

Impacts that should be considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

STEP 5—Evaluate Visibility Impacts.

Modeling should be performed on the pre- and post-control emissions to determine the actual impact on visibility. This step does not need to be performed if the most stringent control technology is chosen.

The following sections of this report review the BART evaluation steps performed by GVEA for Healy Unit 1. As discussed in Section 7 of this report, the predicted visibility impacts for Auxiliary Boiler #1 are well below the 0.5 daily deciview metric established to determine if source emissions will cause or contribute to visibility impairment. Enviroplan agrees with GVEA that, pursuant to 40 CFR 51, Appendix Y, this insignificant source is not subject to the above detailed analyses and the existing configuration is deemed as BART.

The above determination notwithstanding, GVEA submitted an informal review request to the Department on February 24, 2010. GVEA indicated as part of their submittal that the BART NO_x and SO_2 emission limits specified by Enviroplan for Auxiliary Boiler #1 were erroneous. The Department evaluated this assertion and determined that a decimal placement error occurred when the Department converted the Title V operating permit limits for NO_x and SO_2 into a format needed for visibility modeling. Both WRAP and GVEA used these emission rates, which were understated by three orders of magnitude, in their respective visibility modeling analyses. As such, the Department requested Enviroplan to revise the prior GVEA visibility modeling analysis using the correct Auxiliary Boiler #1 emission rates. Enviroplan performed the revised analysis and determined the predicted visibility impacts attributable to the boiler remain below 0.5 deciviews. Enviroplan's analysis and findings are summarized in a memorandum to the Department, included herein as Appendix B. The Department's BART determination for

Auxiliary Boiler #1 remains the existing configuration and the current Title V emission limits (see Tables E-1 and 9-1).

Enviroplan's previous GVEA BART evaluation findings report, dated April 27, 2009, recommended proposed BART controls and NO_x, SO_2 and PM_{10} emission limits for Healy Unit 1. The Department public noticed the April 27, 2009 BART proposal for 35-days (May 12, 2009 - June 15, 2009). Comments were received during the public notice period, and these comments have been addressed in a separate Response to Comments (RTC) document. As such, the following sections of this BART Determination Report include relevant April 27, 2009 proposed BART findings; new information from the RTC as necessary; and revised control costs and conclusions as appropriate.

3. IDENTIFICATION OF ALL AVAILABLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 1)

3.1 NO_x Control Technologies Considered

The following describes the NO_x retrofit technologies deemed by GVEA as potentially feasible for Healy Unit 1. Although not specifically listed below, the existing low NO_x burner/over fire air system is also a feasible NO_x control technology. Enviroplan finds that GVEA has satisfied the BART step 1 requirement, with any additional finding(s) specific to a control option indicated as necessary below.

Optimizing the Existing Low NO_x Burner/Over-Fire Air System (LNB/OFA)

The mechanism used to reduce NO_x emissions with low NO_x burners is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Healy 1 currently has an LNB/OFA system which was installed in 1996. This system has been operating for an extended period of time, and, as indicated by GVEA, while plant personnel have exerted considerable effort to optimize performance (minimize CO within the existing permit NO_x limits), it has not been optimized with the goal of minimizing NO_x emissions. Optimization of the LNB/OFA system could be attempted by utilizing a boiler system consultant with the intent of reaching a guideline NO_x target emissions of 0.23 lb/MMBtu (i.e., the 30-day rolling BART presumptive limit for a 200 MW unit). GVEA is uncertain whether such a limit would be achievable, and have indicated that minimizing NO_x emissions will likely also impact other boiler operating parameters such as loss on ignition (LOI), carbon monoxide (CO), and excess air. GVEA further indicated that the 1994 PSD permit (for HCCP) resulted in extensive discussion between ADEC and GVEA in terms of the need to minimize CO emissions from Healy 1. Based on this indication, GVEA has indicated that BART control options must consider the impact on all emissions when attempting to reduce NO_x.

Relating to the above, Enviroplan requested on October 13, 2008 that GVEA provide additional information on the CO emissions minimization issue. GVEA provided a response on November 11, 2008, which included correspondence letters from 2002 and 2005 between GVEA and ADEC. The correspondence indicated that CO emissions from Healy Unit 1 increased after the LNB/OFA installation was completed in 1998. ADEC indicated the need to minimize CO emissions from Healy Unit 1 through combustion system optimization without sacrificing the unit's low NO_x emissions. However, no permit limit was established for CO emissions from Healy Unit 1.

In addition to the above, GVEA indicated in their November 11, 2008 response that the potential for CO emissions increases were associated not just with the LNB/OFA optimization retrofit scenario; but also with the use of ROFA® (described below) since LNB modification would occur with a ROFA system. Overall, the information and correspondence pertaining to CO emissions as provided by GVEA is acknowledged. It is also understood that such collateral impacts can be considered as an additional environmental impact under the Energy, Environmental and Economic Impacts portion of the BART review process (i.e., Step 4).

However, since visibility impairing pollutants are the focus of BART (i.e., NO_x and not CO); and since there may not be an increase in CO emissions from improved LNB/OFA NO_x control, Enviroplan finds that this is informational only and is not considered further in this review.

Rotating Opposed Fire Air (ROFA®)

Mobotec markets ROFA® as an improved second generation OFA system whereby the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively. A typical ROFA® installation would have a booster fan(s) to supply the high-velocity air to the ROFA® boxes. GVEA noted that Mobotec proposed one 200 horsepower (hp) fan for Healy 1. Mobotec expects to achieve a NO_x emission rate of 0.15 lb/MMBtu using ROFA® technology.

ROFA® with Rotamix®

The Mobotec Rotamix® system is an advanced selective non-catalytic reduction (SNCR) system (also see below) that has been developed to optimize the reduction of unwanted substances, such as NO_x. To optimize NO_x reduction, an amine-based reagent such as ammonia is added. The ammonia is added using lances that are inserted in the ROFA®/Rotamix® nozzles. The high-velocity air in the ROFA® system carries the chemicals into the center of the furnace. Mobotec expects to achieve a NO_x emission rate of 0.11 lb/MMBtu using ROFA/Rotamix® technology.

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reaction of NH_3 and NO_x. SNCR involves injecting urea/NH_3 into the combustion gas path to reduce the NO_x to nitrogen and water. SNCR is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or more commonly urea is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unmarketable, react with sulfur to foul heat exchange surfaces, and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization efficiency and higher operating cost.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x

decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. Sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled or may be emitted from the stack as increased emissions of PM_{10}/$PM_{2.5}$. Fouling can eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result of either prolonged exposure to excessive temperatures, or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a 3-year lifetime to achieve low emission levels for high performance catalyst systems.

SCR manufacturers typically estimate 10 to 20 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which results in ammonia slip. Ammonia slip may increase atmospheric PM formation, which is a visibility impairing pollutant. Thus, an emissions trade off between NO_x and ammonia occurs in high NO_x reduction applications. While SCR may be considered potentially technically feasible for the boilers, there are various concerns with the technology, most notably the temperature required for the catalyst to activate and the unreacted ammonia introduced into the exhaust stream.

SCR works on the same principle as SNCR, but a catalyst is used to promote the reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F to 750°F. Due to the catalyst, the SCR process is more efficient than SNCR. The most common type of SCR is the high-dust configuration, where the catalyst is located upstream of the airheater and downstream from the economizer.

3.2 SO_2 Control Technologies Considered

The following describes the SO_2 retrofit technologies deemed by GVEA as potentially feasible for Healy Unit 1. Although not specifically listed below, the existing dry sorbent flue gas desulfurization (FGD) system is also a feasible SO_2 control technology. Enviroplan finds that GVEA has satisfied the BART step 1 requirement, with any additional finding(s) specific to a control option indicated as necessary below.

Increase sodium bicarbonate injection rate to improve SO_2 removal utilizing the existing dry sorbent injection system

Healy 1 currently operates a dry sorbent injection system which injects sorbent into the flue gas after the air heater and upstream of the baghouse or fabric filter to control SO_2 emissions. Since the system was installed in 1999, GVEA has used three different materials as sorbent in an attempt to maximize the efficiency of the system. When the system was first installed, calcium carbonate was used as the sorbent. Several years later GVEA began experimenting with trona (a sodium sesquicarbonate) and was able to increase SO_2 capture significantly. In 2007, GVEA was able to optimize the system even further by using sodium bicarbonate. The SO_2 in the flue gas reacts with the sodium bicarbonate to form dry particles, which are captured downstream in the existing fabric filter. Under current operation, the dry sodium bicarbonate system consistently achieves approximately 40 to 50 percent removal of SO_2. An increase in the amount of sodium bicarbonate injected may have the potential to achieve SO_2 removal of up to 70 percent.

GVEA has indicated that there are several significant potential issues related to increasing sodium bicarbonate injection with the existing dry sorbent injection system as follows:

1. The existing sorbent injection system design and equipment may not be able to support the required sodium bicarbonate feed rate to remove SO_2 continuously at 70 percent removal. While it may be possible to achieve 70 percent removal on a short-term basis, it is not feasible to operate the existing equipment at that rate continuously with no interruptions.
2. A brown NO_2 plume may be visible at higher SO_2 removal rates based on operational experience on other similar dry sodium injection systems. It is uncertain whether a brown plume would be visible at a 70 percent removal rate.
3. From previous testing at Healy 1 in March 2008, higher sodium bicarbonate injection rates corresponded with higher mercury emissions.

GVEA has indicated that, while it may be possible to operate the current SO_2 FGD system up to a 70 percent removal capability for some periods of time, consistently achieving this removal rate is not feasible when taking into account equipment capacities, SO_2 removal performance, and other environmental impacts. To this end, GVEA submitted additional information on March 18, 2009 pertaining to the optimization of their existing FGD system. The information included re-computed sorbent usage costs; as well as capital costs associated with the installation of new injectors (redundant injection system) needed to achieve a continuous SO_2 removal efficiency of 70 percent. Further information was provided by GVEA on August 27, 2009, in response to an August 17, 2009 request for clarification from the Department. Additional discussion relating to the optimization of the existing FGD system, which is deemed to be a technologically feasibly retrofit option, is presented in Section 6.2 of this report.

With respect to the brown plume issue, Enviroplan agrees with GVEA on the potential for an increased occurrence of visible plumes with increased sorbent usage. A brief literature review performed by Enviroplan (see footnotes *1, 2 and 3* for example) confirmed that the use of sodium reagents in FGD systems can result in the production of a reddish-brown plume coloration in stack gases downstream of the particulate control device. One document opines the belief that some step within the overall sulfation reaction (reaction of sodium reagent with SO_x) initiates the oxidation of NO to NO_2. It is the presence of the NO_2 in the exiting flue gases which is the source of the plume coloration. While the frequency of plume occurrence and possible impacts at DNPP is not possible to predict, Enviroplan does agree that an increase in sorbent usage to reduce SO_2 may be offset with potential deleterious effects on visibility due to brown plume events.

With respect to the increased mercury emissions issue, Enviroplan reviewed GVEA's March 2008 mercury test summary report and found that an increase in sodium bicarbonate sorbent injection rate corresponded to an increase in elemental mercury (Hg) emissions at the FGD system. GVEA has not provided any detailed explanation for this outcome and, as such, the test result is considered to be informational and not deemed as a viable reason to eliminate increased sorbent injection as a retrofit option.

Install lime spray dryer FGD system

The lime spray dryer is a semi-dry sorbent based system that typically injects lime slurry in the top of an installed absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form dry calcium sulfate particles. At Healy 1, this dry particulate matter would be captured downstream in the existing baghouse, along with the fly ash. It is assumed that a lime spray dryer system will produce a dry waste product suitable for landfill disposal. Operation of a lime spray dryer FGD system would result in a wet plume, reduced plume rise, and the potential for higher near field air quality impacts.

Install wet limestone FGD system

Wet limestone FGD systems operate by treating the flue gas in large scrubber vessels with a limestone solution. Wet FGD scrubbers use an absorber tower in which flue gas is contacted by the limestone slurry, resulting in conversion of SO_2, in the flue gas into calcium sulfate (gypsum), with carbon dioxide (CO_2) going up the stack. The calcium sulfate is removed from the scrubber and disposed, and it is assumed that the waste product from a wet limestone scrubber system is suitable for landfill disposal. Operation of a wet limestone FGD system would result in a wet plume, reduced plume rise, and the potential for higher near field air quality impacts.

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[1]Yougen Kong and Jim Vysoky, "Comparison of Sodium Bicarbonate and Trona for SO_2 Mitigation at A Coal-Fired Power Plant", Solvay Chemicals Inc., presented at ELECTRIC POWER 2009, Rosemont, Illinois, May 12-14, 2009.
[2]U.S. EPA. "Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.
[3]"Method For Baghouse Brown Plume Pollution Control", WO/1989/009184, Inventor/Applicant: Richard G. Hooper, taken from World Intellectual Property Organization, http://www.wipo.int/pctdb/en/wo.jsp?IA=US1989001254&DISPLAY=DESC.

3.3 Particulate Control Technologies Considered

Healy 1 currently has a reverse gas baghouse installed for particulate control. The baghouse specifications include 12 compartments, each with 64 bags approximately 33 feet in length and 11.5 inches in diameter, and a design air to cloth ratio of approximately 2.0 with all compartments in service. The baghouse used at Healy 1 achieves a control efficiency of 99.89%. This high efficiency baghouse is a state-of-the-art technology for filterable particulate control for Healy 1. Other control technologies such as a mechanical collector, hot or cold electrostatic precipitators, or wet particulate scrubbers could be considered as additional feasible particulate control options. However, none of these alternative technologies are considered to have the potential of matching the consistent filterable particulate removal performance of a baghouse. Therefore, the existing baghouse is considered BART for Healy 1, and completion of the five-step BART process is not required.

Since GVEA currently uses a high efficiency baghouse for particulate control, Enviroplan agrees with GVEA in finding this control to be BART for this pollutant/emission unit. No additional detailed analyses (steps), including no the visibility modeling analyses, are required for particulate emitted from Healy 1, pursuant to 40 CFR 51, Appendix Y, Section IV.D - Step 1.9.

Comments pertaining to this control system were received from the NPS during the proposed BART 35-day notice period (May 12, 2009 - June 15, 2009). One such comment indicated agreement with the existing baghouse being BART for filterable PM_{10}; however, the commenter specified the need to also evaluate controlling condensable PM_{10}.

As indicated above, the existing baghouse is used for control of filterable particulate matter. The baghouse also provides complimentary benefit to the SO_2 control system (sorbent injection into the ductwork prior to the baghouse resulting in dry sulfate particles captured at the baghouse). At this time, control efficiencies for condensable PM are not well understood (e.g., see Federal Register Notice 74 FR 36427, July 23, 2009). Regardless, it is anticipated that the degree of control of condensable PM will be similar between a cold-side ESP and a baghouse. In addition, the baghouse is capable of a higher emission reduction for filterable PM. Hence, at this time, the Department sees no benefit of adding an additional PM_{10} control device in place of, or in addition to, the existing baghouse for controlling condensable PM.

4. TECHNICALLY FEASIBLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 2)

4.1 NO_x Control Technologies

GVEA based their technical feasibility on physical constraints, the current boiler configuration and size, and impact on boiler operation and efficiency for Healy 1. A summary showing the results of the evaluation process for the NO_x technologies is provided in Table 4-1 below.

Table 4-1: Technically Feasible NO_x Control Options for Healy 1

Control Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Current Operation (i.e., LNB w/OFA)	Yes	--
Optimize Existing LNB w/OFA	Yes	--
LNB w/OFA & SNCR	Yes	--
Replace OFA with ROFA®	Yes	--
ROFA® and Rotamix®	Yes	--
LNB w/OFA & SCR	Yes	--

In their report, GVEA stated that each of the control methods identified above is considered technically feasible for controlling NO_x emissions from Healy 1. Except for the SCR option, GVEA did not consider potential space constraints in their analyses. For SCR, GVEA contracted with an SCR application company to conduct an on-site evaluation of the retrofit potential and related costs for this system (see Section 5.1 below).

4.2 SO_2 Control Technologies

GVEA based their technical feasibility on physical constraints, the current boiler configuration and size, and impact on boiler operation and efficiency for Healy 1. A summary showing the results of the evaluation process for the SO_2 technologies is provided in Table 4-2 below.

Table 4-2: Technically Feasible SO_2 Control Options for Healy 1

Control Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Current Operation	Yes	--
Increase sodium bicarbonate feed rate utilizing existing dry sorbent injection system	Yes	--
Lime Spray Dryer	Yes	--
Wet Limestone FGD System	Yes	--

In their report, GVEA stated that each of the control methods identified above is considered technically feasible for controlling SO_2 emissions from Healy 1. GVEA did not consider potential space constraints in their analyses.

5. EVALUATION OF TECHNICALLY FEASIBLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 3)

In this section, Tables 5-1 and 5-2 indicate the control effectiveness for each group of control technologies. The control efficiencies are relative to the current operation of Healy 1 (i.e., the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system). The projected emission rates reflect a 30-day rolling average, consistent with the BART program requirements for an electric generating unit (EGU). The emission limits are based on vendor information and professional engineering judgment, as provided by GVEA.

5.1 NO_x Control Technologies

The expected NO_x emission rates are summarized in Table 5-1 for each of the NO_x removal technologies designated as feasible in Step 2 (previous Section 4).

Table 5-1: Control Effectiveness of the NO_x Control Options for Healy 1

Control Technology	Control(1) Efficiency (%)	Projected Emission Rate (lb/MMBtu)
Current Operation (LNB w/OFA)	-	0.28
Optimize Existing LNB w/OFA	18.0	0.23(2)
LNB w/OFA & SNCR	32.0	0.19
Replace OFA with ROFA®	46.0	0.15
ROFA and Rotamix®	61.0	0.11
LNB w/OFA & SCR	75.0	0.07

(1) Relative to the current controlled baseline emission rate of 0.28 lb/MMBtu.
(2) Presumptive limit for > 200 MW wall fired boilers burning sub-bituminous coal

Three issues are noted with respect to the information presented in Table 5-1. These issues are based on comments received by the Department during the proposed BART 35-day notice period (May 12 2009 - June 15, 2009). First, comments provided by GVEA specified that a NO_x emission rate of 0.28 lb/MMBtu would be more representative of the existing baseline emissions for Healy 1 than 0.25 lb/MMBtu (i.e., the rate reflected in the April 27, 2009 proposed BART Findings Report). This revision was based on a 5-year analysis performed by GVEA of 30-day rolling NO_x emission rates for Healy 1 from CEM data. As indicated in the RTC document, the baseline controlled emission rate for Healy 1 is revised to 0.28 lb/MMBtu.

Second, as discussed in the RTC document, GVEA provided a refined cost analysis for the SCR retrofit option. GVEA contracted Fuel Tech, a consulting company that specializes in SNCR and SCR application, to inspect the Healy plant; gather additional site-specific data; and more fully assess the capital cost impact associated with a retrofit SCR system designed to meet the 0.07 lb/MMBtu preliminary BART NO_x emission limit. Fuel Tech conducted the evaluation and issued a findings report and cost evaluation on June 10, 2009. As indicated by Fuel Tech, their evaluation was not a detailed engineering study and cost analysis, but it did account for actual current systems setup and plant retrofit design limitations and requirements. The BART Guideline supports the use of site-specific design and other conditions that affect the cost of a particular BART analysis. GVEA's revised SCR cost evaluation using the Fuel Tech study data is reflected in this revised findings document.

Third, comments received from the NPS suggested that GVEA's specified SCR NO_x control efficiency and related emission limit were understated. As indicated in the RTC document, due to uncertainty with respect to continuous system operation in a harsh Alaska environment, with only limited time for catalyst cleaning and system maintenance; and consideration of other determinations for this type of control system, the proposed GVEA emission limit of 0.07 lb/MMBtu has been determined to be adequate for this Healy 1 retrofit option.

5.2 SO_2 Control Technologies

Table 5-2 presents the SO_2 control technologies being evaluated and the expected removal efficiencies and emission rates. The control efficiencies are relative to the current operation of Healy 1 (i.e., the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system). The projected emission rates reflect a 30-day rolling average, consistent with the BART program requirements for an electric generating unit (EGU).

Table 5-2: Control Effectiveness of the SO_2 Control Options for Healy 1

Control Technology	Control[(1)] Efficiency (%)	Projected Emission Rate (lb/MMBtu)
Current Operation (dry sorbent injection FGD system)	NA (50)	0.30
Increase sodium bicarbonate feed rate utilizing existing dry sorbent injection system	40 (up to 70)	0.18
Lime spray dryer (semi-dry FGD)	50 (75)	0.15
Wet limestone FGD	77 (88)	0.07

(1) Relative to the current controlled baseline emission rate of 0.30 lb/MMBtu. The value in parenthesis is the control efficiency relative to an uncontrolled baseline emission rate of 0.60 lb/MMBtu determined from analysis of Usibelli Mine coal, as indicated by GVEA on August 27. 2009.

Comments pertaining to the lime spray dryer (LSD) control system were received from the National Park Service (NPS) during the proposed BART 35-day notice period (May 12, 2009 - June 15, 2009). One such comment suggested that GVEA's specified SO_2 control efficiency and related emission limit for this system were understated. This is a similar comment made by the NPS in February 2009 (a response was provided by the Department at that time). As indicated in the RTC document, due to uncertainty with respect to system capability using the very low Usibelli Mine coal (down to 0.17% sulfur by weight); and consideration of other determinations for this type of control system, the proposed GVEA emission limit of 0.15 lb/MMBtu has been determined to be adequate for this Healy 1 retrofit option. This limit is equivalent to the BART rule EGU presumptive limit for SO_2.

6. COST-EFFECTIVENESS AND IMPACT ANALYSIS (Step 4)

GVEA evaluated the cost of implementing each of the technically feasible control technology. The total capital investment for each control technology when applied specifically to the Healy 1 site and the annual operating and maintenance costs were calculated. These cost calculations were based on the following:

- CUECost Workbook, Version 1.0.
- CH2M HILL's internal proprietary database.
- Budgetary quotes from equipment vendors.
- Quotes or cost estimation for previous design/build projects or in-house engineering estimates.
- Site-specific retrofit and cost evaluations for a selective catalytic reduction (SCR) system.

GVEA calculated the cost-effectiveness of each control technology from the cost of implementation and the amount of pollutant reduced. Cost-effectiveness is defined as the cost of control per ton of pollutant removed, and it is determined on an annualized basis. The annual reduction in pollutant emission rate (tons/year) for each retrofit control option is determined relative to a baseline anticipated annual emission rate. As explained by GVEA in their January 2009 final report submittal, the baseline anticipated annual emission rates for Healy 1 (NO_x and SO_2) are derived from the boiler heat input capacity of 340 MMBtu/hr and the average actual emission rates determined from 2008 CEMs data (i.e., (0.28 lb/MMBtu and 0.30 lb/MMBtu for NO_x and SO_2, respectively). The use of annual anticipated pollutant emission rates is consistent with 40 CFR 51, Appendix Y, Section IV.D, Step 4 for purposes of determining cost effectiveness. The current existing respective NO_x and SO_2 emissions control configurations of LNB/OFA and dry FGD for Healy Unit 1 are reflected in these baseline emission rates.

It is noted that the "baseline" emission rates used for cost effectiveness determination purposes, as described above, are not the same "baseline" emission rates used by GVEA in their CALPUFF visibility modeling assessment. For purposes of visibility modeling (see Section 7 of this report), the BART rule requires an affected source to use "peak" 24-hour emission rates as the basis for modeling their pre-control (i.e., existing or baseline) configuration. Peak 24-hour emission rates, which were used by GVEA in their visibility modeling analysis, are higher than the annual anticipated pollutant emission rates described above.

The cost analysis described above was presented in the April 27, 2009 proposed BART Findings Report. Comments pertaining to proposed BART were received from GVEA during the related 35-day notice period (May 12, 2009 - June 15, 2009). All comments from GVEA have been addressed in the RTC document. Three GVEA comments of note pertaining to the general approach used in the cost analysis are discussed below.

- GVEA commented that Section IV.D.4.k of the BART rule (40 CFR 51, Appendix Y) provides for the consideration of a unit's *remaining useful life* when amortizing control system costs. GVEA indicated the remaining useful lifetime of Healy 1 to be approximately 15 years from current (2009). As such, GVEA requested the Department approve a revised SCR cost analysis they submitted during the comment period that used an 8-year cost amortization period determined as follows: Alaska regional haze implementation plan (SIP) timeline would likely require BART retrofit controls (and emission limits) to be installed by

2016, resulting in an 8-year remaining useful life (and cost amortization period) for Healy 1 (i.e., 2009 + 15 = 2024; 2024 - 2016 = 8 years). As indicated in the RTC document, the Department agrees that the referenced BART rule citation supports GVEA's use of the 8-year amortization period in their cost analysis. It is nonetheless noted that the site-specific SCR cost evaluation performed by Fuel Tech (see Sections 5-1 and 6-1) has resulted in SCR being determined as cost ineffective, irrespective of the amortization period used in the cost analysis.

- GVEA provided the 8-year cost analysis described above for the SCR option only. As such, the Department requested Enviroplan to re-compute the GVEA cost analyses for all remaining NO_x and SO_2 retrofit options using an 8-year capital cost amortization period (O&M costs are not affected by amortization, and these costs as previously provided by GVEA remain unchanged unless otherwise noted herein). The costs presented in following Sections 6-1 and 6-2 are revised accordingly. The revisions do not escalate present (2009) costs to 2016 costs. Non-escalated current costs were applied herein to simplify the analysis since cost comparison metrics were not escalated by GVEA in a similar manner.
- The NPS commented that the GVEA BART cost analysis should have utilized the OAQPS Control Cost Manual as per the BART Guidelines. As indicated in the RTC document, while the BART Guideline (40 CFR 51, Appendix Y, Section IV.D.4.a.5) does recommend use of the Control Cost Manual for cost consistency purposes "where possible", the Guideline does not exclusively require use of this document. Since the EPA's CUECost tool has been developed for cost estimation of air pollution control systems installed on coal-fired utility emission units, Enviroplan believes CUECost, as reflected in the GVEA cost analyses, to be suitable for the BART cost analysis. CUECost has been applied by other BART affected source owners/operators (see, for example footnote 4).

One potential metric that can be used as a starting point in terms of deciding the acceptability of the cost effectiveness of a potential BART control is the BART rule itself. In its June 24, 2005 Regional Haze Final Rule Preamble, EPA estimated ranges of cost effectiveness, as shown below, that were used to establish presumptive NO_x and SO_2 emission limits for EGUs. It is noted that the Healy 1 unit does not fall in the category listed in 40 CFR 51, Appendix Y as a unit subject to the presumptive emission limits. Further, the costs presented below are not considered as ceiling values never to be exceeded, and they must be considered in combination with the findings of the other steps of the BART determination process. Nevertheless, these values are considered as a point of reference in this cost effectiveness evaluation process.

- $400 to $2000 per ton of SO_2 removed.
- $100 to $1500 per ton of NO_x removed.

6.1 NO_x Control Technologies

Table 6-1 below provides a summary of the annual operating costs, the total tons of NO_x removed, and the average annual cost effectiveness for each NO_x retrofit control system. The information presented in Table 6-1 is reflective of costing provided by GVEA (applicant), as revised by Enviroplan to reflect an 8-year capital cost amortization period in accordance with 40 CFR 51, Appendix Y, Section IV.D.4.k, as discussed in the previous section.

[4] State of Oregon, Department of Environmental Quality, "Agenda Item J, Action Item: 2008 Oregon Regional Haze Plan and new controls for PGE Boardman coal-fired power plant proposed rulemaking", Attachment B, Summary of Comments and DEQ Response, June 18-19, 2009 EQC Meeting.

Table 6-1: NO_x Cost Effectiveness Summary for Healy 1

Remaining Useful Life	Cost Item	Optimize Existing LNB w/OFA	SNCR	ROFA	ROFA/ Rotamix	SCR[(1)]
8 Years[(2)]	Total Installed Capital Cost	$20,000 ($1/kw)	$2,538,900 ($102/kw)	$4,572,000 ($183/kw)	$6,912,000 ($276/kw)	$21,860,887 ($874/kw)
	Capital[(3)] Recovery	$3,480	$441,794	$795,574	$1,202,757	$3,804,013
	Fixed and Variable O&M Costs	$0	$122,191	$138,852	$287,309	$1,125,172
	Total Annualized Cost	$3,480	$563,985	$934,426	$1,490,066	$4,929,185
	Tons NO_x [(4)] Removed	74	134	194	253	313
	Average Cost Effectiveness ($/ton)	$47	$4,208	$4,827	$5,886	$15,762
	Incremental Cost Effectiveness ($/ton)	$47	$9,409	$6,219	$9,328	$57,734

Notes:

(1) Based on the 0.28 lb/MMBtu scenario as presented in the June 15, 2009 letter to ADEC from Kristen DuBois of GVEA.
(2) Based 40 CFR 51, Appendix Y, Section IV.D.4.k (i.e., a 15-year remaining useful lifetime (from 2009) for Healy 1 specified by GVEA and an expected AK regional haze SIP emission limit and pollution control install applicability date of 2016).
(3) Based on a capital recovery factor of 0.17401 for 8 years at 8%.
(4) Relative to baseline emission rate of 0.28 lb/MMBtu.

The following is noted with respect to the results of Table 6-1. The April 27, 2009 proposed BART Findings Report recommended installation of an SCR system as BART NO_x control for Healy 1. This recommendation was based on a review of all related information submitted to the Department, largely from GVEA; and the requirements of the federal and state BART rule. Comments pertaining to proposed BART were received from GVEA during the related 35-day notice period (May 12, 2009 - June 15, 2009). Of note, GVEA disagreed with the SCR proposed BART finding and Enviroplan's cost analysis found in Section 6.1 of the April 2009 Findings Report (which was based on the Control Cost Manual). As such, GVEA decided to contract a SCR application consulting company to conduct an on-site evaluation and develop a refined cost estimate for a retrofit SCR system for Healy 1. The consultant, Fuel Tech, Inc., conducted the evaluation on May 27, 2009. Fuel Tech provided a project report to GVEA on June 10, 2009 (this was included with GVEA's June 15, 2009 proposed BART comments). Fuel Tech estimated the site-specific capital cost for the SCR retrofit project at $13,300,000. Related costs for project management, engineering, equipment relocation, demolition, new induced draft fan and motor, duct stiffening, and other onsite modifications; and relevant operation and maintenance (O&M) costs, were estimated by GVEA per Fuel Tech recommendations. Since the BART Guideline supports the use of site-specific design and other conditions that affect the cost of a particular BART analysis, GVEA revised their SCR cost evaluation using the Fuel Tech study data. As discussed in the RTC document, Enviroplan reviewed the information and generally agreed with the analysis; however, a minor revision was made to eliminate double-counting of certain O&M costs, which was acknowledged by GVEA on August 27, 2009. Also, current (2009) cost estimates were used instead of GVEA escalated 2016 cost estimates, as explained in the preceding section of this report.

The most effective NO_x retrofit control system, in terms of reduced emissions, that is considered to be technically feasible for Healy 1 includes combustion controls (LNB/OFA) with post-combustion SCR. This combination of controls should be capable of achieving the lowest controlled NO_x emission rate on a continuous basis. The effectiveness of the SCR system is dependent on several site-specific system variables, including the size of the SCR, catalyst layers, NH_3/NO_x stoichiometric ratio, NH_3 slip, and catalyst deactivation rate; however, GVEA has indicated an emission limit of 0.07 lb NO_x/MMBtu should be achievable for Unit 1. This retrofit option is relatively expensive and reflects the most costly option of all retrofit options considered (total annualized cost of almost $5 million).

The least expensive NO_x retrofit control system that is considered technically feasible for Healy 1 is the optimization of the current LNB/OFA system. This control option is expected to achieve an average control efficiency improvement of approximately 18% versus the current existing configuration at a relatively inexpensive annualized cost (8-year amortization) of approximately $3,480. However, while optimization is considered as a potential retrofit option in their analysis, GVEA has expressed their uncertainty whether optimization of the existing LNB+OFA system can actually achieve the NO_x reduction assumed by GVEA for this option.

In terms of assessing the cost effectiveness and economic viability of the SCR option, the April 2009 Findings Report referenced a compilation of SCR retrofit cost analyses for BART eligible boilers prepared in January 2009 by the NPS[5]. The NPS study results estimated SCR retrofit capital investment costs in the range of $80/kW to $270/kW. The site-specific SCR cost ($/kW) shown in Table 6-1 is more than three times greater than the upper bound of this cost range.

6.1.1 Cost of Compliance

The average annual cost effectiveness for NO_x control on Healy 1, based on 8-year amortization of capital costs, ranges from $47/ton for the optimization of the current LNB+OFA system to over $15,700 for existing combustion controls plus SCR on Healy 1; with a related total capital investment ranging from $1/kW (optimization) to about $870/kW for SCR.

With the exception of optimization, the annual cost effectiveness of each retrofit option exceeds EPA's presumptive EGU level for BART ($1500/ton), as presented earlier in this Section 6. While the presumptive cost is exceeded by at least a factor of two, as already indicated herein, the presumptive costing information is not a ceiling value; instead, it is a guideline value that must be considered in combination with the findings of the other BART analyses (steps).

6.1.2 Energy Impact

Evaluation of the energy factor indicates that there is no significant energy penalty associated with the optimization of the current LNB and OFA system. However, operation of an SCR system has certain collateral environmental consequences. In order to maintain low NO_x emissions some excess ammonia will pass through the SCR. Ammonia slip will increase with lower NO_x emission limits, and will also tend to increase as the catalyst becomes deactivated. The application of an SCR system would also consume power and reduce efficiency, thereby decreasing energy available to consumers. The additional electrical demand will consume

[5] Email forwarded Don Shepherd, NPS, to various recipients, entitled "SCR Capabilities and Costs", dated January 9, 2009.

almost 0.5 percent of the total generating capacity of Healy Unit 1. These energy impacts are included in the operational costs as part of the economic impact analysis.

6.1.3 Non-Air Quality Environmental Impacts

Evaluation of the non-air quality environmental impacts indicates that there are no non-air quality related impacts associated with the optimization of the current LNB and OFA system. However, SCR requires some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored there will be risk management requirements associated with ammonia storage. Also, production of ammonia primarily uses a finite resource (natural gas), so use of ammonia could have long term consequences on fossil fuel supplies. In addition, SCR may cause enough ammonia accumulation in ash to make the ash not usable for cement and other beneficial uses. Currently, the plant sells much of its ash for such beneficial uses. If the ash is contaminated by ammonia, there will be associated environmental impacts in the form of additional land use requirements. Since both SNCR and Mobotec Rotamix® also rely on the use of a urea or ammonia reagent, use of these systems may similarly result in excess ammonia emissions (slip); ammonia storage and management issues; and possible non-salability of ash and the need to landfill the ash in a regulated solid waste facility.

6.2 SO_2 Control Technologies

Table 6-2 below provides a summary of the expected annual operating costs, the total tons of SO_2 removed, and the average annual cost effectiveness for each SO_2 retrofit control system. The information presented in Table 6-2 is reflective of costing provided by GVEA, as revised by Enviroplan to reflect an 8-year capital cost amortization period in accordance with 40 CFR 51, Appendix Y, Section IV.D.4.k, as discussed in Section 6 above.

Table 6-2: SO_2 Cost Effectiveness Summary for Healy 1

Remaining Useful Life	Cost Item	Optimization of Dry Sorbent Injection System	Semi-Dry FGD (Lime Spray Dryer)	Wet Limestone FGD
8 Years(1)	Total Installed Capital Cost	$2,000,000 ($80/kw)	$8,357,143 ($334/kw)	$15,042,857 ($602/kw)
	Capital Recovery(2)	$348,020	$1,454,227	$2,617,608
	Fixed and Variable O&M Costs	$405,782(3)	$631,511	$901,654
	Total Annualized Cost	$753,802	$2,085,738	$3,519,262
	Tons SO_2 Removed(4)	179	223	343
	Average Cost Effectiveness(5) ($/ton)	$4,218	$9,337	$10,275
	Incremental Cost Effectiveness ($/ton)	$4,218	$29,813	$12,033

Notes:

(1) Based 40 CFR 51, Appendix Y, Section IV.D.4.k (i.e., a 15-year remaining useful lifetime (from 2009) for Healy 1 specified by GVEA and an expected AK regional haze SIP emission limit and pollution control install applicability date of 2016).

(2) Based on a capital recovery factor of 0.17401 for 8 years at 8%.

(3) Fixed and variable O&M costs based on Enviroplan's estimates of the additional reagent and other related costs required to achieve 70% control (relative to the existing 50% control baseline), using a coal having an uncontrolled SO_2 emission rate of 0.60 lb/MMBtu.

(4) Relative to baseline emission rate of 0.30 lb/MMBtu.

(5) Annual and incremental costs for the dry sorbent injection optimization control scenario (70% control) were calculated relative to the existing (baseline) dry sorbent control scenario (50% control). Average costs for other options calculated relative to the existing controlled baseline.

The following is noted with respect to Table 6-1. The April 27, 2009 proposed BART Findings Report included optimizing the existing dry FGD system (i.e., increasing the sodium bicarbonate sorbent feed rate) as a SO_2 retrofit option for Healy 1. Section 6.2 of the April 2009 report discussed the cost analysis for that option, which was revised by GVEA on March 18, 2009. In summary, the optimization scenario reflects increasing sorbent injection from 370 lb/hr (current baseline) to a sorbent usage rate that equates to a continuous 70 percent SO_2 reduction relative to an uncontrolled emission rate (i.e., additional 40 percent reduction relative to the current baseline rate). GVEA estimated the optimized sorbent feed rate to be between 700 lb/hr to 1400 lb/hr; and the related sorbent cost to be $0.5 to $1.0 million ($750,000 average was assumed for BART economic evaluation purposes). Comments on this analysis were received from the Sierra Club during the related 35-day notice period (May 12, 2009 - June 15, 2009). As detailed in the RTC document, the Sierra Club noted a potential inaccuracy in the sorbent increase estimate based on relevant information specified in a Department of Energy document[6]. In response to this comment, Enviroplan requested clarifying information (through the Department) from GVEA on August 17, 2009; received the requested information on August 27, 2009; and revised both the Sierra Club/GVEA additional sorbent usage estimate and the related retrofit option costs. The details of such are contained in the RTC document, and the results are reflected in Table 6-2.

6.2.1 Cost of Compliance

The annual average cost effectiveness for SO_2 control on Healy 1, based on 8-year amortization of capital costs, is $4,218/ton for the optimized existing FGD option and greater than $9,000/ton for both the wet FGD system and lime spray dryer options. EPA estimated that for a majority of BART eligible units greater than 200 MW, cost of control systems used to meet the presumptive SO_2 emission limits is $400 to $2,000 per ton of SO_2 removed (see 70 FR 39133). Therefore, for two of the options the average effectiveness of SO_2 removal at Healy 1 is more than quadruple the upper bound cost effectiveness calculated by EPA for SO_2 control on large EGUs. For existing FGD optimization the presumptive cost, which is a guideline value and not a ceiling value, is exceeded by at least a factor of two. The wet limestone FGD system control option is expected to achieve an average control efficiency of approximately 77% from current controlled baseline at an annualized cost of over $3.5 million; the lime spray dryer control option is expected to achieve 50% from current baseline at an annualized cost of almost $2.1 million; and optimizing the existing FGD system is expected to achieve 40% from baseline at an annualized cost of about $750,000.

6.2.2 Energy Impact

Evaluation of the energy factor indicates that the installation of a new wet limestone FGD system would require additional power. Auxiliary power is required for material handling, reactant preparation, pumps, mixers, and to overcome significant pressure drops through the reaction vessels. Based on the economic analysis performed, the auxiliary power requirement for wet FGD control system is approximately 0.94% of the gross energy output of the generating unit. Healy 1 has a gross rating of 25 MW; therefore, auxiliary power requirements for FGD control system would be approximately 240 kilowatts (kW). Energy impacts associated with each control technology were included in the BART economic impact evaluation as an auxiliary power cost.

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[6] U.S. Department of Energy, "*Integrated Dry NO_x/SO_2 Emissions Control System Sodium-Based Dry Sorbent Injection Test Report*", DOE Contract Number DE-FC22-91 PC90550, Final Report April 1997.

6.2.3 Non-Air Quality Environmental Impacts

Evaluation of the non-air quality environmental impacts indicates that the installation of a new wet limestone FGD system will also result in the storage of new chemicals onsite and a new waste stream for the facility. The exit flue gas stack temperature with both of these technologies will be less than the current operation, thus flue gas buoyancy will be decreased. In addition, saturated flue gas would significantly increase the probability of creating fog during the summer and ice fog during the winter, in the area surrounding the plant.

6.3 Economic Impacts – Rate Payer Analysis

The April 27, 2009 proposed BART Findings Report, Section 6.3, included an analysis of the potential costs to GVEA residential rate payers for the SCR (NO_x) and increased sorbent injection (SO_2) BART control scenarios for Healy 1. Comments pertaining to proposed BART were received from GVEA and the NPS during the related 35-day notice period (May 12, 2009 - June 15, 2009). Of note, the NPS disagreed with the analysis and suggested it was not supported by the BART rule; and GVEA disagreed with the resultant percent increase in costs to rate payers should SCR and FGD optimization be required for installation. As detailed in the RTC document, and as reflected below, 40 CFR 51, Appendix Y, Section IV.E.3 supports the rate payer cost consideration. As such, this report has revised the rate payer cost analysis to reflect the capital cost revisions pertaining to the existing FGD optimization option (see discussion in Section 6.2 above). Further, the prior rate payer cost analysis which considered SCR for NOx control has been replaced with the SNCR option (see conclusions section later in this document). The RTC document provides further detail on these changes; however, the revised results are reflected in Tables 6-3-3 and 6-3-4 below.

The above notwithstanding, during February 2009 conversations with the Department, GVEA requested that rate payer cost considerations be included as part of the cost of compliance with the BART rule. Rate payer cost analysis information was not provided, nor considered, by GVEA in their July 2008 and January 2009 BART analysis submittals. However, 40 CFR 51, Appendix Y, Section IV.D, Step 4, does allow for unusual circumstances that exist for a source that might lead to unreasonable cost-effectiveness estimates. Further, 40 CFR 51, Appendix Y, Section IV.E provides for summarization of costs of compliance using cost-effective measures relevant to the source. As such, the Department agreed to such considerations and GVEA provided rate payer cost data and analyses on March 18, 24 and 30, 2009.

The BART rule provides that the energy impacts analysis may consider whether a particular control alternative would result in a significant economic disruption within the area or region of the affected source. As such, the unique geographic and economic characteristics affecting the business community within Alaska, including power producers, justify that the potential control costs consider the economic impact on each customer, expressed in units of cost per kilowatt-hour. Below is a list of attributes that describe the communities served by GVEA.

- The community is not connected to a nationwide or outside electric grid or connected to other utilities;
- The community does not have access to large scale alternative power generation options (continuous hydro-power, geothermal energy, and wind energy);

- The stationary source is owned by a small publicly owned non-profit association and electricity rates would be adjusted to account for any increased facility costs; and
- The stationary source is located in a remote area, which is not accessible year round for economical supply of fuel and reagent.

The GVEA rate payer base is small relative to typical electric utilities within the continental United States. GVEA residential customers paid $0.17705/kWh in the year 2008. As established by the Department of Energy, the "Representative Average Unit Cost" of electricity for a residential user is $0.0973/kWh. So, a residential customer of GVEA pays 180 percent of the national average. Given this relatively high cost to GVEA residential rate payers, the costs of BART control systems have been evaluated by GVEA on a per rate payer basis. The following presents a summary of Enviroplan's April 27, 2009 findings associated with our review of GVEA's rate payer analysis that was based on the SCR (NO_x) and increased FGD sorbent injection (SO_2) BART control options:

- GVEA rate payer analysis submitted on March 18, 2009:
  - The rate payer analysis reflected combined costs for NOx and SO_2 control systems, and it did not include individual control system cost analyses
  - Rate payer analyses were presented for both GVEA (i.e., entire plant) and Healy Unit 1, based on budget and electric output projections for 2009
  - Rate payer analysis based on non-fuel expenses only (did not include fuel costs)
  - Results showed an incremental rate payer increase due to BART controls of:
    - 3.3% when compared to annual average rate payer costs for entire plant
    - 36% when compared to annual average rate payer cost for Healy Unit 1 alone
  - GVEA specified a 25% increase in energy charge to rate payers since 2002
  - GVEA specified the 25% increase does not include rising fuel costs which are passed directly to their customers
  - GVEA expects in 2010 another 5.6% increase in energy charge, for a total increase since 2002 of 30.6%
  - GVEA notes the national average rate payer cost as of November 2008 to be 9.73 cents/kW-hr (average Alaska cost for November 2008 was 14.28 cents/kW-hr), while GVEA's rate payer cost for November 2008 was 19.502 cents/kW-hr
  - GVEA qualitatively indicates the rate payer costs to be proportionally higher than for utilities with a large rate base (GVEA residential rate base is 36,860 customers)
- Supplemental GVEA rate payer analysis information submitted on March 29, 2009:
  - Rate payer analysis provided for individual NOx and SO_2 control systems, with findings of:
    - 1.86% rate payer increase for SO_2 control system (increased sorbent injection)
    - 1.41% rate payer increase for NO_x control system (SCR)
  - GVEA provided 2008 annual average residential customer energy charge of 17.705 cents/kW-hr
- Enviroplan reviewed GVEA increased rate payer estimates and determined different percent increases to the rate payers as follows:
  - 0.70% rate payer increase for SO_2 control system
  - 0.43% rate payer increase for NO_x control system

- Differences between Enviroplan and GVEA findings due to:
  - Enviroplan revised (reduced) GVEA's March 2009 control system capital cost information
  - Enviroplan used 2008 annual average residential rate payer cost, as provided by GVEA (17.705 cents/kW-hr) as the basis for determining incremental increases to rate payers, rather than using the 2009 nonfuel costs as used by GVEA
  - Enviroplan only considered incremental rate payer cost increases relative to operating GVEA (i.e., the entire plant), and, no consideration is given to incremental cost increases relative to only operating Healy Unit 1

Tables 6-3-1 and 6-3-2 present GVEA's rate payer cost analysis results from the April 27, 2009 findings report.

Table 6-3-1: GVEA Estimated Operating Expenses for the SCR NOx Control Option

2009 Non-Fuel Cost ($)	Post Control Non-Fuel Cost ($)	2009 Anticipated Total Sales (kWh)	2009 Non-Fuel Cost per kWh ($/kWh)	Post Control Non-Fuel Cost pe kWh ($/kWh)	Percent Increase (%)
89,299,216	90,562,467	1,380,383,090	0.06469	0.06561	1.41

Notes:
2009 non-fuel cost per kWh ($/kWh): $89,299,216 / 1,380,383,090 kWh = $0.06469/kWh
Post controls non-fuel cost per kWh ($/kWh): $90,562,467 / 1,380,383,090 kWh = $0.06561/kWh

Table 6-3-2: GVEA Estimated Operating Expenses for the FGD Optimization SO_2 Control Option

2009 Non-Fuel Cost ($)	Post Control Non-Fuel Cost ($)	2009 Anticipated Total Sales (kWh)	2009 Non-Fuel Cost per kWh ($/kWh)	Post Control Non-Fuel Cost pe kWh ($/kWh)	Percent Increase (%)
89,299,216	90,955,806	1,380,383,090	0.06469	0.06589	1.86

Notes:
2009 non-fuel cost per kWh ($/kWh): $89,299,216 / 1,380,383,090 kWh = $0.06469/kWh
Post controls non-fuel cost per kWh ($/kWh): $90,955,806 / 1,380,383,090 kWh = $0.06589/kWh

As discussed in the RTC document, Enviroplan has revised the April 27, 2009 GVEA rate payer cost estimates presented in the preceding tables. The revision is based, in part, on the control system cost revisions discussed in Section 6. Further, the GVEA analyses shown above do not include fuel costs. Enviroplan understands that fuel costs are highly variable; however, this is a direct cost born by each ratepayer and its exclusion could result in a bias (overstatement) in the percent increase computed in this analysis. As such, Enviroplan utilized the actual 2008 annual average ratepayer cost provided by GVEA as the baseline for determining percent ratepayer increases due to the BART control systems. Tables 6-3-3 and 6-3-4 present Enviroplan's estimated rate payer cost increases for SNCR (in place of SCR that was considered in the April 27, 2009 report) and increased sorbent injection.

Table 6-3-3: Enviroplan Estimate of Healy Plant Ratepayer Expense Due to Implementation of the SNCR NOx Control Option

Parameter	Cost
Annualized Total Cost [1]	$563,985
Cost Associated w/SNCR ($/kWh) [2]	$0.00041
Avg Ratepayer Cost for 2008 ($/kWh) [3]	$0.17705
Percent Increase due to SNCR	0.23%
@500kW-hr/month	$0.21/month and $2.46/year
@1,000kW-hr/month	$0.41/month and $4.92/year

Table Notes:
1. Reflects depreciation over 8 years at an 8 percent interest rate (i.e., 0.17410 capital recovery factor).
2. Reflects control cost relative to total plant sales (i.e,. total annualized control system cost/2009 anticipated total sales (kWh)).
3. Provided by GVEA.

Table 6-3-4: Enviroplan Estimate of Healy Plant Ratepayer Expense Due to Implementation of FGD Optimization SO_2 Control Option

Parameter	Cost
Annualized Total Cost [1]	$639,442
Cost Associated w/FGD Optimization ($/kWh) [2]	$0.00046
Avg Ratepayer Cost for 2008 ($/kWh) [3]	$0.17705
Increase due to Injection System	0.26%
@500kW-hr/month	$0.23/month and $2.76/year
@1,000kW-hr/month	$0.46/month and $5.52/year

Table Notes:
1. Reflects depreciation over 15 years at an 8 percent interest rate (i.e., 0.11683 capital recovery factor).
2. Reflects control cost relative to total plant sales (i.e,. total annualized control system cost/2009 anticipated total sales (kWh)).
3. Provided by GVEA.

While the rate payer cost analysis presented above is determined in reference to the BART rule, the Department has considered similar rate payer cost impacts for major source (PSD sources) control technology evaluations (i.e., BACT). For the two tables shown immediately above, the similar approach to determining rate payer costs as found in the Technical Analysis Report (TAR) to Permit AQ0215CPT02 was applied.

Based on the information tabulated in Tables 6-3-3 and 6-3-4, use of the GVEA 2008 ratepayer cost, which includes fuel and non-fuel charges, results in a potential ratepayer increase of 0.23% and 0.26% for the SO_2 and NO_x control systems, respectively. When considering these BART controls for GVEA, the total incremental increase above the 2008 average rate payer cost is estimated to be 0.49 percent. For a family that uses 500 kWh/month, this would equate to a combined cost increase of about $5.20/year; and about $10.40/year for a family that uses 1,000 kWh/month.

Enviroplan acknowledges the incremental costs associated with the individual installations of these control options; however, we do not believe these costs to be prohibitive in terms of the assessing the viability of either emissions reduction system. It is noted that the increase in the cost to a residential rate payer is presented on a per control option basis (i.e., does not reflect the total combined costs of both the NO_x and SO_2 control system options). The BART rule requirements are specific in that the BART emission limitations (and possible retrofit control technologies) are to be determined on a per visibility impairing pollutant (VIP) basis, and not on a combined VIP basis.

7. VISIBILITY IMPACTS EVALUATION (Step 5)

Pursuant to 40 CFR 51, Appendix Y and 18 AAC 50.260, the BART determination must include an evaluation of the impacts associated with the installation of various control options regarding potential visibility benefits in Class I areas. As provided by 18 AAC 50.260(h)(3)(A), GVEA opted to conduct their visibility modeling analysis in accordance with the modeling protocol developed by the Western Regional Air Partners (WRAP) - Regional Modeling Center (RMC).

The visibility modeling analysis conducted by GVEA and their consultant, CH2M Hill, is intended to comply with 40 CFR 51, Appendix Y, Section IV.D - Step 5, "*How should I determine visibility impacts in the BART determination?.*" GVEA conducted the analysis to support their control analysis and proposed BART determinations. Since GVEA currently uses a high efficiency baghouse for particulate control, which is considered BART for this pollutant/emission unit, no specific visibility modeling analyses are required for particulates pursuant to 40 CFR 51, Appendix Y, Section IV.D - Step 1.9. For the feasible NO_x and SO_2 retrofit control technology options presented in Section 4, GVEA estimated the visibility impacts according to the following sequence:

- Model pre-control (i.e., existing baseline) emissions
- Model individual post-control emissions scenarios
- Determine degree of visibility improvement
- Factor visibility modeling results into BART "five-step" evaluation, including a visibility cost effectiveness metric expressed as cost of control option per deciview improvement ($/dV)

The following sections provide the findings associated with the methods used by GVEA to evaluate the visibility impacts at the DNPP Class I area and the potential visibility improvements associated with the retrofit technologies evaluated by GVEA.

7.1 CALPUFF Modeling Approach

GVEA used the CALPUFF modeling system to estimate their visibility impacts. Their approach is described in Section 4 of the GVEA January 2009 BART control analysis report. However, Enviroplan also relied on the following information, as needed, as part of the review:

- July 2008 BART analysis report and companion CALPUFF modeling files prepared by CH2M Hill, and submitted by GVEA on July 28, 2008;
- October 16, 2008 letter from Enviroplan to the Department requesting clarification and additional information pertaining to the July 2008 submittal (which the Department forwarded to GVEA and CH2M Hill on October 16, 2008);
- November 11, 2008 submittal by GVEA of CH2M Hill responses to the October 16, 2008 Enviroplan letter, along with the revised CALPUFF modeling files submitted on behalf of GVEA by CH2M Hill;
- December 4, 2008 letter from Enviroplan to the Department requesting further clarification and additional information pertaining to the November 11, 2008 submittal (which the Department forwarded to GVEA and CH2M Hill on December 4, 2008);

- December 11, 2008: Teleconference between the Department Enviroplan, CH2M Hill, GVEA, to discuss the December 4, 2008 Enviroplan letter and a draft response provided by GVEA on December 10, 2008;
- Final revised January 2009 BART analysis report prepared by CH2M Hill; and a companion "GVEA Healy BART Response to 12/04/08 Comments from Enviroplan" document, submitted by GVEA on January 2, 2009. No further changes were made to the November, 2008 CALPUFF modeling files.
- Teleconferences between the Department, GVEA, CH2M Hill and Enviroplan on February 25 and 27, 2009 and March 2, 2009; and related BART study information submitted on March 18, 2009 with additional clarifying information submitted on March 24 and 30, 2009. No further changes were made to the November, 2008 CALPUFF modeling files.

In addition to the above, the Department received comment on the April 27, 2009 proposed BART Findings Report during the related 35-day public notice period (May 12, 2009 - June 15, 2009). Of note, the NPS disagreed with several aspects of the visibility modeling analysis. While all comments from the NPS (and all other commenter's) have been addressed in the RTC document, the following clarifications are provided in relation to the visibility modeling and the NPS comments:

- The GVEA visibility modeling analysis did not include a GEP stack height analysis to assess the potential for aerodynamic building downwash of affected source stacks and plumes. This approach is consistent with the WRAP modeling protocol which was followed by GVEA to conduct their visibility impact analysis.
- The GVEA visibility modeling analysis did not include a receptor-by-receptor impact evaluation at DNPP for pre- and post-control options. The BART Guideline does not require such an analysis. Instead, pursuant to the Guideline, ranked delta-deciview visibility impacts were determined by GVEA using CALPOST for the pre- and post-control scenarios. While the BART Guideline requires a comparison of the 98th percent days for the pre- and post-control scenarios, GVEA conducted the required comparative assessment using maximum delta-deciview values (pre- versus post-control) since only one year of meteorological data was used in the analysis. This is approach is consistent with Department BART modeling requirements.
- GVEA modeled the Healy 1 total PM_{10} emissions without speciation, with total PM_{10} assumed equal to $PM_{2.5}$. The Department has acknowledged the use of unspeciated PM_{10} emissions data in the BART visibility modeling[7]; therefore, GVEA's use of total PM_{10} (as $PM_{2.5}$) as input to the CALPUFF modeling is consistent with the WRAP protocol, as adopted by the Department, and the WRAP CALPUFF modeling input files.

In addition to the above, comments were received by GVEA during the 35-day notice period that results in a change to the Healy 1 baseline NOx emission rate from 0.25 to 0.28 lb/MMBtu (see related discussion in Section 5.1). This baseline emission rate reflects a 30-day rolling emission rate used for the cost analysis, and it does not affect the peak 24-hour NOx emission rate used in the visibility impact modeling.

[7]*Summary of WRAP RMC BART Modeling for Alaska, Draft #7, dated April 6, 2007.*

Finally, GVEA submitted a request for an informal review on February 24, 2010 pertaining to specific BART determination findings, including the correction to certain findings as necessary (e.g., see Section 2 herein). The Department's decisions relating to GVEA's review request are incorporated into this final BART determination as necessary.

The following discussion presents findings related to the GVEA CALPUFF visibility modeling analysis.

BART-Eligible Source Emission Rates and Stack Parameters

Section 4.0 of the final GVEA BART study report presents the emissions inventory data used in the visibility modeling analysis. The following summarizes the information used in the CALPUFF input files, and any findings relating to review of this information:

- Review of the CALPUFF input files provided by GVEA (November 2008) indicates that the stack parameters and emission rates shown in the final report Table 4-3 and 4-4 have been used in the CALPUFF visibility modeling.
- The NO_x, SO_2 and PM_{10} emission rates used in the CALPUFF modeling for Auxiliary Boiler #1 are consistent with the emission rates used by WRAP. However, as discussed in both Section 2 and Appendix B herein, the Department determined the boiler's modeled NO_x and SO_2 emission rates were inadvertently understated by three orders of magnitude. Enviroplan re-evaluated the visibility impacts attributable to the boiler using the corrected emission rates (see Appendix B).
- The PM_{10} emission rate used in the modeling analysis for Unit 1 is based on a 2004 stack test. It is noted that a review of the WRAP-RMC CALPUFF input files for Unit 1 indicated that no particulate matter emission rate was used by WRAP for this unit. This notwithstanding, GVEA/CH2M Hill has correctly used the stated PM_{10} emission rate in their July 2008 visibility modeling, and their resubmitted November 11, 2008 visibility modeling.
- Auxiliary Boiler #1 stack exit parameters used in the CALPUFF modeling are consistent with the same parameters used in the WRAP modeling. The modeled stack parameters used by GVEA for Unit 1 reflect more accurate information based on a reevaluation of the physical characteristics of the stack, as indicated by GVEA in their November 11, 2008 response.
- For each BART eligible source, all PM_{10} emitted has been assumed as $PM_{2.5}$, which is consistent with the WRAP modeling.
- Stack parameters for each control scenario have been provided by GVEA that reflect the anticipated changes associated with installation of each control technology alternative being evaluated.
- The NO_x and SO_2 emission rates used in the CALPUFF modeling for Unit 1 are based on continuous emissions monitoring (CEM) data recorded by GVEA for the period May 1, 2007 through April 30, 2008. 40 CFR 51, Appendix Y recommends that the pre-control emissions (i.e., existing configuration) be modeled using "*the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled*". Calendar year 2002 is the meteorological period modeled by WRAP. CH2M Hill clarified on 11/11/08 that GVEA did not have readily available emissions information for 2002 due to a recent CEMs system upgrade; therefore, the most recent one-year period (5/1/07 - 4/20/08) was used as a

surrogate data period. Section 4.3.3 of the GVEA final report indicates the CEM data represents a realistic depiction of anticipated annual emissions for the unit. Due to the lack of 2002 actual emissions information, the current CEM data is - an acceptable surrogate data set for this analysis.

- GVEA modeled their current (existing) control configuration using two emission rate scenarios. GVEA used the "peak 24-hour" NO_x and SO_2 emission rates for their "baseline" scenario. GVEA also developed a "null" scenario wherein they used an "anticipated 24-hour" emission rate for the "controlled" pollutant (e.g., SO_2 when evaluating the existing dry FGD system), and the "peak" emission rate for the "other" pollutant (e.g., NO_x when evaluating the existing dry FGD system). The "anticipated" emission rates reflect the 24-hour emission rates averaged over a full-year of boiler operation. The 24-hour average NO_x and SO_2 emission rates for the respective "baseline" and "anticipated" configurations, expressed as hourly emission rates, are summarized below:

Scenario*	NO_x (lb/hr)	SO_2 (lb/hr)
Baseline ("peak" 24hour average emission rates)	151.0	182.2
Null ("anticipated" 24hour average emission rates)	85.0	102.0

*Both scenarios reflect existing controls, i.e., low NOx burners/over-fire air and dry sodium bicarbonate flue gas desulfurization (FGD) system

Enviroplan initially believed that GVEA used the "anticipated" emission rates to determine modeled emission rates for the other retrofit control scenarios. However, GVEA clarified during the February 25 and 27, 2009 teleconferences that the modeled "null" option was presented for informational purposes only, and that it was not used as the basis for establishing modeled emission rates for each retrofit control option. GVEA indicated that the emission rates used for each retrofit control option were based on vendor information and professional engineering judgment; and they did not multiply the retrofit control efficiencies presented in their report (e.g., Table 3-2) by the "null" 24-hour emission rates. Finally, GVEA clarified that the control efficiencies were used only for control cost determination purposes (in conjunction with "null" emission rates). This is acceptable for control cost purposes only, since 40 CFR 51, Appendix Y, Section IV.D., Step 4, suggests that a realistic depiction of anticipated annual emissions be used for cost estimation purposes.

Based on the above, Enviroplan has determined that the NO_x and SO_2 emission rates used in the visibility modeling analysis for each retrofit scenario are correct; and the modeling results for the "null" configuration have been ignored. Likewise, the visibility modeling summary results presented in Tables 4-7 and 5-1 of the GVEA 2009 study report are correct. Findings associated with our review of these results tables are presented at the end of this section.

CALMET Modeling Procedures

The CALMET modeling methods and input file have been compared for consistency with the recommendations of the WRAP protocol. GVEA's CALMET modeling approach is summarized below:

- CALMET version 6.211, level 060411;

- CALMET modeling performed for one year (2002) as recommended in the protocol, using scripts and inputs to recreate the CALMET output for the study;
- 15-km resolution 2002 MM5 data taken from the WRAP website (http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calmm5/ak/2002/); and
- GVEA summarized the following information in their final report, which has been compared to the WRAP protocol and it was found to be consistent:
  - CALMET input parameters and options used by GVEA, as summarized in final report Table 4-1;
  - the meteorological surface stations, as specified in Table 4-2; and
  - the vertical layer resolution, and modeling domain extent and resolution, as specified in Section 4.2.1,

The data described by GVEA in their final study report and used in the CALMET input files are consistent with the WRAP protocol.

<u>CALPUFF Modeling Procedures</u>

The CALPUFF modeling methods and the related model input options selected for use in this study have been reviewed for consistency with the WRAP protocol and related BART guidance documents. Applied modeling procedures and any findings are summarized as follows:

- CALPUFF version 6.112, level 060412;
- CALPUFF modeling performed for one year (2002), consistent with WRAP modeling;
- EPA CASTNET hourly ozone data from Denali, using 40 ppb default for missing hours;
- A background ammonia concentration of 0.1 ppb (Note that this is consistent with the WRAP protocol which GVEA is using pursuant to 18 AAC 50.260(h)(3)(A), even though the U.S. Fish and Wildlife Service (FWS) has requested BART sources developing their own modeling protocols to assume a background concentration of 0.5 ppb);
- Regulatory default model options when such options are specified;
- National Park Service discrete receptor locations and elevations for DNPP (http://www2.nature.nps.gov/air/maps/Receptors/index.cfm);
- Aerodynamic building downwash not used in the modeling analysis; and
- CALPUFF computational domain consistent with the CALMET meteorological domain (NX=275, NY=325).

The data described by GVEA in their final study report and used in the CALPUFF input files are consistent with the WRAP protocol.

<u>CALPOST Modeling Procedures</u>

The CALPUFF post-processing methods of CALPOST and the related model input options selected for this study have been reviewed for consistency with the WRAP protocol and related

BART guidance documents. Applied modeling procedures and any findings are summarized as follows:

- CALPOST version 6.131, level 060410;
- Particle growth curve f(RH) for hygroscopic species based on EPA (2003) f(RH) tabulation;
- CALPOST default extinction efficiencies for PM fine (PMF), PM coarse (PMC), ammonium sulfate, ammonium nitrate, organic carbon (OC), and elemental carbon (EC);
- Calculation of background extinction and change to extinction using the recommended CALPOST Method 6 (MVISBK=6);
- Monthly relative humidity adjustment factors specific to the DNPP Class I area as taken from Table A-3 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003); and
- Annual average natural background aerosol concentrations as taken from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003).

The data described by GVEA in their final study report and used in the CALPOST input files are consistent with the WRAP protocol.

7.2 Visibility Modeling Results

As supported in EPA's BART rules and guidelines, when conducting visible impact modeling using only one year of meteorological data, source impacts should reflect the maximum change to the daily Haze Index (HI) as compared to a natural background, expressed in units of delta-deciviews (ΔdV). In their July 2008 report, GVEA utilized 98th percentile delta-deciview visibility predictions; however, pursuant to the BART rules, this is permissible only when modeling multiple years of meteorology (e.g., 3-years). The final January 2009 report correctly presented modeling results as maximum values (Tables 4-7 and 5-1 of the final report). Additionally, the BART rules and 18 AAC 50.260 have established 0.5 daily deciviews (dV) as the metric against which predicted visibility impacts should be compared for purposes of establishing whether a source causes or contributes to impairment of visibility.

Table 4-7 of GVEA's final report presents a summary of the highest delta-deciview visibility predictions from the one year (2002) of modeling at the DNPP Class I area for each NO_x and SO_2 emissions control scenario. Table 4-7 also presents the number of days predicted to exceed the significance level of 0.5 dV for each scenario, along with related visible cost effectiveness values (e.g., $/deciview improvement). Table 5-1 of the final report presents the change (i.e., improvement) in model prediction results when comparing "baseline" visibility predictions to the alternate control scenarios.

7.3 Visibility Monitoring Program

In addition to performing the required retrofit scenario visibility impact analysis as part of the overall BART control determination analysis, GVEA indicated in the January 2009 final report that they previously conducted a visibility monitoring program (VMP). GVEA provided in Section 1.0 of their final report a summary of the VMP, which is abbreviated below.

GVEA received a PSD permit in 1994 to expand the Healy power plant and construct the Healy Clean Coal Project (HCCP), a 50-megawatt (MW) coal-fired unit, adjacent to the existing 25 MW Unit 1. Based on a 1993 Memorandum of Agreement (MOA), Condition 26 of the permit required GVEA to develop a VMP and operate visibility monitoring equipment for the period prior to the initial startup of the HCCP through the completion of 1 full year of commercial operation of HCCP. The VMP, which was public noticed and approved by EPA, ADEC and the National Park Service (NPS), had the objective of collecting sufficient visual and measurement data to:

1. Provide reasonable assurance that NO_x, SO_2, and particle emissions from the HCCP and Healy Unit 1 sources were not adversely impairing visibility within the DNPP Class I area; and

2. Evaluate any trained NPS observer's reports of visibility impairment for their potential attribution to NO_x, SO_2, and particle emissions from operations of HCCP and Unit 1.

Under the VMP, photographic and air quality instrumentation was established at three monitoring stations, i.e., Garner Hill site overlooking the plant; the DNPP visitor's center, and the Bison Gulch ambient air monitoring station at the Park boundary. Continuous time-lapse video of Healy was taken at Garner Hill and Nenana Valley north of the DNPP Visitor Access Center. Measurements of meteorological data, SO_2 concentrations, and nephalometer readings of light scattering by sulfate particles were taken at Bison Gulch for use in estimating the contribution of the SO_2 emissions from the Healy Power Plant (Healy 1 and HCCP) to light scattering by particles within DNPP.

The VMP commenced in late December 1997, just prior to HCCP beginning its first year of the demonstration period. During the VMP time period, Healy 1 was operating with the current NO_x control configuration and the current baghouse, but the current FGD SO_2 reduction system, which was installed during 1999, was not operating. Therefore, the VMP occurred when both units were operating and Healy 1 was emitting more SO_2 than under the current configuration (with the FGD system). GVEA notes that HCCP had not been fully optimized during the VMP, resulting in emissions above normal operating conditions.

By condition of the permit, the duration of the VMP was only to occur for 2 years (1 year of demonstration operation and 1 year of commercial operation). Quarterly reports were submitted to ADEC, EPA and the NPS during the program. In 2000, the ADEC, EPA and NPS agreed the VMP could be temporarily shut down as HCCP never reached full commercial operation. HCCP has not operated since that time. GVEA indicated the results of the program demonstrated that no visibility impairment was observed by trained NPS observers while Healy 1 was operating at full load; and that actual visibility impairment at DNPP from Healy was not detectable while both units (Healy 1 and HCCP) operated. Further, GVEA indicates there were occasions during the VMP when a slight plume was visible and recorded by video, but no correlation was reached between this slight plume and any visibility issues within DNPP.

Coincident with the VMP, a three year study was conducted in which particles that cause or contribute to regional haze were measured and analyzed to determine if Healy was *contributing to regional haze. The study was funded by GVEA, managed by the NPS, and conducted by Air Resource Specialists, Inc. and the University of Alaska–Fairbanks. Results of this study are summarized in a report entitled "Final Report on the Results from the Poker Flat, Denali National Park and Preserve, and Trapper Creek CASTNET Protocol Sites, July 1998 through June 2001." Per GVEA, the report concluded that there was no specific indication that operations from the Healy Power Plant contributed to regional haze.*

GVEA concluded that the Unit 1 existing control configuration for all pollutants is BART. This conclusion is based in part on GVEA's assertion that no visibility impairment at DNPP, attributable to Healy, has been observed by trained NPS observers based on the previous visibility studies described above. GVEA further asserted during the February 27, 2009 teleconference with the Department that no visibility impairment has occurred at DNPP. This assertion was repeated in GVEA's comments to the Department on the April 27, 2009 proposed BART Findings Report. A response to this further assertion is provided later in this section, with a similar discussion provided by the Department in the RTC document.

In considering the relevance of the prior VMP in making a preliminary determination of BART for Healy 1 (and Auxiliary Boiler #1), several VMP related documents were provided by both ADEC and GVEA for consideration as part of this review/findings report. However, ADEC noted that they could *not* find evidence as to whether the VMP documents had ever been approved, or even fully reviewed by ADEC, EPA or the NPS. GVEA in their January 2009 submittal concurred, indicating that they knew of no formal correspondence from ADEC, EPA or the NPS regarding the acceptability of the visibility monitoring program and studies.

Enviroplan therefore conducted a limited review of the VMP related materials and correspondence as part of the BART review. Based on this limited review, Enviroplan notes the following:

- The monitoring program would have occurred at a time of greater potential for plant emissions, given the operation of HCCP and no FGD system in place on Unit 1.
- The above notwithstanding, correspondence from ADEC to GVEA on 12/14/99 expressed concern over whether both boilers were operating during the year at typical, full operating rates representative of normal maximum emission rates. It is known that HCCP did not reach full operational status. However, it is unclear whether Unit 1 was at full capacity during the VMP, although Section 1 of GVEA's final report (summarized above) indicates this to be the case.
- It is acknowledged that the NPS did not identify any visibility events during the 2-year monitoring period which would have required further investigation by GVEA. It is also acknowledged that the EPA/NPS/ADEC approved on May 1, 2000 the shutdown of the visibility monitors. However, it is unclear whether lack of correspondence from the NPS during the monitoring program is indicative of agency concurrence with GVEA that no instances of visible plume events occurred that would have required further investigation.
- A very limited review of quarterly video monitoring program results has been conducted by Enviroplan. The quarterly data capture rates are generally high. While relatively few events ("anomalies") are identified in the reports, events are nonetheless identified. For instance, the initial report submitted for the 1st quarter 1998 identifies several events wherein the plant's plume may have entered the Class I area. The same report also indicates the NPS

observers did not report any events. It is unclear whether the lack of reporting by the NPS observer means there was no visible impact at DNPP from Healy during any of these events.

Based on the above, Enviroplan recognizes the general findings of GVEA's VMP and the actual monitored visibility impacts from Healy at the DNPP Class I area. However, Enviroplan has concluded that these results, even if accurately summarized by GVEA in their final report, cannot be considered in terms of the BART control determination for Healy Unit 1 for the following reasons:

- The MOA did not address possible future requirements. A BART Determinations is a case by case evaluation of retrofit technology. Existing emissions reduction technology factors into this evaluation by reducing the number of additional retrofit technologies available and by reducing the cost effectiveness of adding those retrofit technologies. The Department and its contractor included these factors in its evaluation of the available technologies
- In a February 10, 2009 teleconference between the National Park Service (NPS) and the Department, the NPS noted that the VMP conducted by GVEA was a plume blight monitoring study (i.e., monitoring study focusing on the potential impact of a plume of specified emissions for specific transport and dispersion conditions), the results of which cannot be used to satisfy the requirements of the BART program which pertains to visibility impairment due to regional haze.
- There is a lack of formal agency acknowledgement and approval of the results and findings of the VMP.
- It is not clear whether the NPS agreed with the findings in the quarterly monitoring summary reports, and the conclusion by GVEA that no reporting by the NPS equates to no visible impacts by Healy at DNPP during an "anomalous" event.
- The BART rule does not exempt a source from considering impacts associated with visibility modeling if a source has conducted visibility monitoring.
- The BART rule does not indicate that all feasible retrofit technologies can be dismissed if a source has conducted visibility monitoring which suggests no or limited visible impacts at the nearest Class I area.
- The VMP has limited application and is not completely relevant to the BART rule. Specifically, an air dispersion model (CALPUFF in this case) is a tool used to assess potential air quality impacts associated with emissions from a source (or sources). Typically, air modeling is conducted over a large geographic area to ensure air quality compliance. While an ambient monitoring program provides actual measurement and impact information, such data is limited to the specific location or area where the monitoring equipment is sited. As such, while air dispersion models tend to be conservative predictors of air quality versus similarly measured data, the BART rule requires a visibility assessment at the entire Class I area and not simply at select locations at or near the area (i.e., the three VMP locations).

In addition to the above, during a February 27, 2009 teleconference with the Department, GVEA noted that use of a dispersion model, i.e., CALPUFF, is "theoretical" in its application. GVEA requested that greater consideration of real data, e.g., their VMP, be given by the Department when determining BART since no visibility impairment has been monitored at DNPP. In response to this request, Enviroplan has conducted an evaluation of potential impairment at DNPP and its relation to the current Alaska BART/SIP effort for reducing visibility impacts.

This evaluation is based primarily on visibility monitoring data collected at the DNPP IMPROVE monitor site, plus other available information provided by the Department relating to regional haze studies at DNPP. As summary of our review and findings follows below.

The federal Regional Haze Rule requires that states develop plans that include reasonable progress goals for improving visibility in Class I areas to natural conditions by 2064. Natural visibility conditions are intended to represent the long-term visibility in Class I areas without man-made impairment. Specifically, a state is required to set progress goals for Class I areas that: 1) provide for an improvement in visibility for the 20% most impaired (i.e., worst visibility) days and 2) ensure no degradation in visibility for the 20% least impaired (i.e., best visibility) days. Based on the U.S. EPA default approach for estimating natural visibility conditions, the 20% best visibility and 20% worst visibility days at the Denali National Park and Preserve have been estimated to be 2.30 and 7.42 deciviews (dv), respectively (U.S. EPA, "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA-454/B-03-005, September 2003).

The 2000-2004 average, or baseline, visibility for Denali for the 20% worst days is 9.9 dv, based on data collected at the Denali IMPROVE monitor site. This baseline value, which is higher than the natural visibility deciview value of 7.42, indicates that a rate of progress of 0.04 dv per year is needed for the Class I area to meet natural conditions by 2064. The 2000-2004 baseline, as well as more recent IMPROVE data at Denali, clearly indicate that there is visibility impairment at the Class I area (i.e., the area is not currently at natural conditions).

An inspection of the IMPROVE particulate matter chemical speciation data indicates the year-round presence of sulfates and nitrates, which are primarily derived from combustion sources. The acidic sulfate aerosols that comprise Arctic Haze are known to have a substantial impact on visibility at Denali primarily during November-May and are believed to originate mainly from industrial emissions in northern Europe and Asia. Local (i.e., Alaskan) industrial sources of sulfates and nitrates also exist, which may impact visibility within the Denali Class I area year-round.

Further technical evidence suggests that emissions from the GVEA Healy Power Plant potentially contribute to visibility impairment within the Denali Class I area. An analysis of air trajectories using the National Oceanic and Atmospheric Administration Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model indicates that Denali is impacted to some degree by atmospheric transport from the northeast, which suggests that emissions from the GVEA Healy Power Plant potentially contribute to visibility impairment within the Class I area (Hafner, W.D., N.N. Solorzano, and D.A. Jaffe, "Analysis of Rainfall and Fine Aerosol Data Using Clustered trajectory Analysis for National Park Sites in the Western U.S.," *Atmospheric Environment* (2007)). Furthermore, the CALPUFF modeling that was conducted by CH2M Hill in support of the GVEA Healy Power Plant BART Analysis (Final Report submitted January 2, 2009) clearly indicates that emissions from the GVEA plant are expected to impact Denali. The CALPUFF Model simulates the influences of complex terrain on plume transport over local and regional scales. This modeling utilized one full year (2002) of 15-km resolution MM5 data, surface meteorological data from five sites, local terrain and land use data, and emissions and stack parameter data for the 25-MW boiler (Healy Unit #1). CALPUFF modeling results indicated that, under plant baseline (i.e., existing (pre-BART) control) operating conditions, the Denali Class I area was significantly impacted by the boiler emissions 136 days during the year, as defined by a deciview value of 0.5 or greater, and had a maximum delta-deciview value (i.e., above the natural background) of 3.359 dv.

In summary, based on a review of IMPROVE and other relevant data, Enviroplan has determined that DNPP is not without visibility impairment, and it is likely that GVEA is a contributor to this impairment. With respect to GVEA's statement regarding the "theoretical" nature of a dispersion model, it is emphasized that CALPUFF is the regulatory dispersion model recommended by EPA for application in the BART determination process (40 CFR 51, Appendix Y). The CALPUFF model has been utilized by WRAP - RMC in their visibility modeling analysis. The BART rule does not provide an exemption from visibility impact modeling if ambient monitoring data are available. Based on these regulatory provisions, as well as the IMPROVE and other data evaluations discussed above, it is determined that the GVEA visibility monitoring program does not otherwise replace the CALPUFF visibility modeling results considered in this BART determination process for GVEA.

7.4 Visibility Impacts Evaluation Conclusions

A detailed review of the GVEA BART-eligible source visibility modeling analysis has been conducted for the Healy power plant Unit 1 and Auxiliary Boiler #1. A limited review of materials pertaining to the 2-year visibility monitoring program performed by GVEA at the DNPP Class I area also has been conducted. Enviroplan presents the following conclusions pertaining to GVEA's visibility impacts determination:

- The CALPUFF visibility modeling analyses are in conformance with the protocol used by WRAP – RMC ("Draft Final Modeling Protocol CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States", August 15, 2006), and WRAP's, "Summary of WRAP RMC BART Modeling for Alaska" (Draft#7, April 6, 2007).
- The CALPUFF visibility modeling analyses are generally in conformance with the Federal and State BART guidelines. While GVEA did consider two modeling scenarios for the current configuration, their use of peak 24-hour emission rates to reflect a "baseline" plant configuration is consistent with the BART rule. No consideration is given to their modeled "null" scenario.
- Maximum predicted visibility impacts for Auxiliary Boiler #1 (0.067 dV) are well below the 0.5 deciview significant visibility impairment metric. Consistent with the individual source attribution approach in Appendix Y, no additional controls are required for this unit.
- Each NO_x emissions control option considered for Unit 1 results in a greater than significant visibility improvement (i.e., greater than 0.5 dV) when compared against the maximum predicted daily visibility impact "baseline" scenario, with the low NO_x burner/OFA plus SCR system showing the greatest visibility improvement (3.359 ΔdV versus 2.573 ΔdV, or a 0.786 dV reduction).
- For the SO_2 emissions control options considered for Unit 1, the retrofit scenario of increased sorbent feed rate to the existing FGD results in only a 0.25 dV improvement versus the impacts associated with the baseline scenario (i.e., ½ of the significance level), and the visibility impacts associated with a lime spray dryer FGD system and wet limestone FGD system are worse than the current baseline configuration due to reduced plume height from a relatively

colder, wetter plume. Coincidentally, the number of days exceeding the significance level (0.5 dV) increases for each of these control options versus the current baseline configuration.

- On February 12, 2009 and during the proposed BART comment period, the NPS commented on the predicted worsening of modeled visibility impacts attributable to the lime spray dryer FGD system and wet limestone FGD system. The NPS questioned the use of CALPUFF and GVEA's receptor grid. The bases for these comments are unclear. The Department, EPA and the federal land managers (which included the NPS) discussed the basic modeling approach several years ago so that these types of issues could be resolved *before* WRAP and industry conducted their assessments. GVEA followed the 2006 WRAP modeling protocol, which the Department discussed with the NPS during the protocol development phase. The Department also had subsequent modeling conversations with the NPS (and industry) regarding source-specific assessments, without the NPS ever challenging the modeling platform (other than which version of CALPUFF should be used and which of the numerous "switches" in CALPUFF should be selected). The NPS likewise did not challenge the use of CALPUFF when the Department adopted the WRAP protocol by reference in its BART regulations. Therefore, the Department deems this comment as extremely delinquent, especially considering that a model change at this point of the process would mean further substantive delays to the development of the state's visibility SIP. In regards to the receptor grid comment, WRAP and GVEA used an NPS-generated receptor grid which they obtained through an NPS their web-site. The Department sees no merit in changing modeling approaches, as it is too late in the SIP development process to make such a substantive change. Visibility-related cost effectiveness information is provided for each NO_x emissions control scenario in terms of both deciviews and days above 0.5 dV reduced. This information is summarized below:

Table 7-1: Visibility Improvement and Annual Costs for NO_x Control Options*

BART Controls	Highest dV Reduction (ΔdV)	Reduction in Avg. No. of Days Above 0.5 dV (Days)	Annualized Cost ($/Year)	Cost per dV Reduction ($/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV ($/Day Reduced)
Optimizing Existing LNB w/ OFA	0.560	43	$3,480	$6,214	$81
Replace OFA w/ ROFA®	0.671	56	$934,426	$1,392,587	$16,686
Replace OFA w/ ROFA® and Rotamix®	0.736	67	$1,490,066	$2,024,546	$22,240
LNB/OFA/SNCR	0.620	51	$563,985	$909,653	$11,059
LNB/OFA/SCR	0.786	71	$4,929,185	$6,271,228	$69,425

*Reflects 8-year capital cost amortization period.

Aside from the current baseline configuration, the most cost effective additional control is optimization of the existing configuration (low NO_x burners/OFA). The most costly control expressed in dV and days above 0.5 dV is the addition of an SCR system. Similar cost effectiveness information is presented for the SO_2 control scenarios; however, costing information for the lime spray dryer FGD system and wet limestone FGD systems expressed in terms of visibility metrics are not meaningful since the visibility impacts worsen under these control scenarios.

Table 7-2: Visibility Improvement and Annual Costs for SOx Control Options(1)

BART Controls	Highest dV Reduction (ΔdV)	Reduction in Avg. No. of Days Above 0.5 dV (Days)	Annualized Cost ($/Year)	Cost per dV Reduction ($/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV ($/Day Reduced)
Increase Dry Sodium Bicarbonate FGD System (increase feed rate)	0.250	39	$753,802	$3,015,208	$19,328
Install Lime Spray Dryer FGD System	-0.870	20	$2,085,738	-$2,397,400(2)	$104,287
Install Wet FGD System	-1.160	18	$3,519,262	-$3,033,847(2)	$195,515

(1) Reflects 8-year capital cost amortization period.
(2) Reflects an increase in visibility impact versus existing baseline impacts.

Overall, the results of the modeling demonstrate that no controls are required for Auxiliary Boiler #1. Also, the lime spray dryer FGD system and wet limestone FGD system SO_2 retrofit options for Unit 1 show a worsening of visible impacts as predicted at DNPP, and Enviroplan agrees with GVEA that these options are not considered viable as SO_2 BART for Unit 1. Enviroplan also finds that the high cost effectiveness associated with an insignificant prediction of visibility improvement from increased sorbent injection at the existing FGD system, when combined with the findings associated with other steps in the BART analysis process, i.e., increased potential for visible impacts (brown plume), results in the sorbent injection increase option not being viable as SO_2 BART for Unit 1.

8. PROPOSED BART FOR HEALY 1

The proposed BART for Healy 1 presented in the April 27, 2009 BART Findings Report included installation of a SCR control system for additional NO_x control; the existing dry FGD sodium carbonate injection system for continued SO_2 control; and the existing fabric filter (baghouse) for filterable particulate (and SO_2) control. Comments pertaining to proposed BART were received during the related 35-day notice period (May 12, 2009 - June 15, 2009); and, as indicated in this document, all comments have been addressed in the RTC document. As discussed in this report, several of the comments have resulted in changes to the Healy 1 NO_x and SO_2 retrofit option cost analyses and emission rates.

In addition to the above, comments were received from GVEA and the NPS pertaining to the relevance of other BART determinations and their costs, which should be considered when determining BART for Healy 1. The RTC document provides a detailed response to these comments, including tabular summaries of other BART determinations for similar EGUs to Healy 1. The tabular summaries were derived from August 2009 NPS survey data[8] for western U.S. primarily coal-fired EGUs. The Department has considered the NPS survey data in deciding a final BART determination for Healy 1. Appendix A to this Findings Report includes the NO_x and SO_2 statistical data summaries derived from the NPS survey data. This information is reflected in the decisions discussed below.

The following sections discuss the BART control recommended for Healy 1.

8.1 NO_x Control at Healy Unit 1

Table 8-1 presents a comparison matrix of the GVEA-evaluated NO_x control options as they relate to the BART 5-step control review process. The cost effectiveness information is based on an 8-year remaining useful lifetime of Healy 1 as referenced from the projected SIP required retrofit control implementation date of calendar year 2016 (i.e., end date of calendar year 2024). As discussed in Section 6 of this document, the BART rule does support the use of the 8-year lifetime period for the amortization of capital control costs.

[8] NPS BART Evaluation, http://www.wrapair.org/forums/ssjf/bart.html .

Table 8-1: Comparison Matrix of the GVEA-Evaluated NO_x Control Options as they Relate to the BART 5-Step Evaluation Process

Control Option	BART Analysis Steps				
	Identify All Control Options (Step 1)	**Eliminate Technically Infeasible Options (Step 2)**	**Evaluation of Control Effectiveness[2] (Step 3)**	**Cost-Effectiveness and Impacts Analysis[3] (Step 4)**	**Visibility Impact Evaluation[4] (Step 5)**
Existing LNB w/OFA[1]	Option Identified	Option Accepted	0% (0.28 lb/MMBtu)	N/A	N/A
Optimize Existing LNB w/OFA	Option Identified	Option Accepted	18% (0.23 lb/MMBtu; 74 add'l tons NO_x removed)	\$47/ton NO_x (annual) \$47/ton NO_x (incremental) \$6,214/deciview	0.560 deciview improvement; 43 day improvement
LNB w/OFA, plus new SNCR system	Option Identified	Option Accepted	32% (0.19 lb/MMBtu; 134 add'l tons NO_x removed)	\$4,208/ton NO_x (annual) \$9,409/ton NO_x (incremental) \$909,653/deciview	0.620 deciview improvement; 51 day improvement
Replace OFA w/ROFA®	Option Identified	Option Accepted	46% (0.15 lb/MMBtu; 194 add'l tons NO_x removed)	\$4,827/ton NO_x (annual) \$6,219/ton NO_x (incremental) \$1,392,587/deciview	0.671 deciview improvement; 56 day improvement
Replace OFA w/ROFA® & Rotamix®	Option Identified	Option Accepted	61% (0.11 lb/MMBtu; 253 add'l tons NO_x removed)	\$5,886/ton NO_x (annual) \$9,328/ton NO_x (incremental) \$2,024,546/deciview	0.736 deciview improvement; 67 day improvement
LNB w/OFA, plus new SCR system	Option Identified	Option Accepted	75% (0.07 lb/MMBtu; 313 add'l tons NO_x x removed)	\$15,762/ton NO_x (annual) \$57,734/ton NO_x (incremental) \$6,271,228/deciview	0.786 deciview improvement; 71 day improvement

Notes:
(1) The existing controlled NO_x baseline emission rate is 0.28 lb/MMBtu (30-day average). No effectiveness, capital or operating costs, or visibility improvements are applicable to this existing control scenario.
(2) Percent control (%) is relative to the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system. The NO_x emission limit corresponding to the option; and the additional amount of NO_x removed (tons/year) for this control scenario versus existing baseline is also shown.
(3) Cost-effectiveness estimates based on 8-year Healy 1 remaining useful lifetime.
(4) Visibility impacts for each option are relative to existing baseline conditions.

GVEA has proposed the existing low NO_x burner and over fire air NO_x emissions control system as BART for Healy 1. In our April 27, 2009 proposed BART Findings Report, Enviroplan recommended the addition of SCR to the existing LNB/OFA system; however, the site-specific cost evaluation and revised cost analysis discussed herein have resulted in the installation of SCR being deemed cost prohibitive.

The above notwithstanding, Enviroplan recommends the final BART determination for Healy Unit 1 to be a NO_x emission limit consistent with a new SNCR system. It is emphasized that the recommendation is not the installation of SNCR; rather, it is the NO_x emission limit that would be achieved should GVEA opt to install an SNCR system on Healy 1 to comply with this limit.

This final BART determination is proposed by Enviroplan for the Unit 1 BART-eligible source pursuant to 18 AAC 50.260(l).

As indicated in 40 CFR 51, Appendix Y, the underlying goal of the BART rule, and the regional haze program, relates to the Clean Air Act's national goal of eliminating man-made visibility impairment from all Class I areas. Based on these regulatory programs; 18 ACC 50.260; and all of the information presented herein in response to these programs, Enviroplan believes the NO_x emission limit equivalent to the SNCR control retrofit option for Healy 1 represents the best combination of factors (steps evaluated) under the BART rule and regional haze program for the purpose of improving visibility impairment at DNPP Class I area. The basis for this determination is as follows:

1. Healy 1 Power Plant is located in very close proximity (about 8 km) to the DNPP Class I area, with the potential for substantive visible impacts at the Class I area (as predicted with CALPUFF).
2. The Healy 1 unit already utilizes the best system of particulate pollutant control (high efficiency baghouse), and the existing configuration for SO_2 control (FGD system) is considered as BART (see below). However, various alternative retrofit NO_x controls are potentially applicable to Healy 1 for substantive additional reduction in unit NO_x emissions.
3. When compared to the existing baseline configuration for Healy 1, visibility modeling of each retrofit option, including optimizing the existing LNB/OFA system, shows predicted significant visibility improvement (greater than 0.5 deciviews) at DNPP; with a coincident predicted reduction of about 1.5 months (or more) in total days exceeding 0.5 deciviews.
4. When compared to the full range of EGUs, as well as the subset of EGUs whose capacities are relatively comparably with Healy 1 (25 MW), the cost effectiveness of each retrofit system except the optimization option is greater than the NPS survey's maximum dollars per ton of pollutant removed metric (i.e., about \$3800/ton as shown in Appendix A). The SNCR option is about 11 percent above this cost, while the most expensive option, SCR, is approximately 15 times this cost.
5. Except for the SCR option, when expressed in dollars per deciview improved (\$/dv) each retrofit option is cost effective in comparison to the NPS survey's mean and median cost values (Appendix A) for other EGUs, including those EGUs relatively comparable in capacity (<110 MW) to Healy 1.
6. Comparison of each option's cost metrics suggests optimization of the existing LNB/OFA system to be the most cost effective retrofit option; however, GVEA has expressed doubt about the ability of this option to achieve the NOx reduction and emission limit expressed in Table 8-1.
7. The SNCR (and Rotamix®) option can employ a urea-based reagent to minimize deleterious environmental impacts associated with ammonia-based reagent handling/storage systems.
8. GVEA has indicated in their January 2009 report that the ROFA® (and optimization) option <u>may</u> result in increased carbon monoxide (CO) and level of ignition (unburnt carbon) emissions.
9. The visibility impact modeling done for Healy 1 indicates that the existing LNB/OFA system results in 136 days per year when the visibility impacts attributable to Healy 1 exceed 0.5 deciviews at DNPP. The NO_x emission limit equivalent to the SNCR control option reduces

the number of days with modeled impacts over 0.5 deciviews to 85. The NO_x emission limit for this option significantly reduces the predicted number of days with modeled impacts over 0.5 deciviews by an additional 51 days per year.

10. The NO_x emission limit equivalent to the SNCR control option will reduce the highest delta deciview impacts from 3.359 ΔdV to 2.739 ΔdV, which is a reduction in visible impacts in excess of the significance metric, 0.5 dV.
11. The NO_x emission limit equivalent to the SNCR option is expected to reduce NO_x emissions by 32% from existing baseline emissions, which equates to 134 tons of additional NO_x emissions removed from the Healy 1 exhaust gas stream.
12. Although the cost effectiveness for the SNCR option is greater than the presumptive $1500/ton cost effectiveness value cited in the preamble to the EPA's BART Guideline (70 FR 39135), the $1500 effectiveness value is not a ceiling value, and it must be considered with all other BART review aspects and control cost effectiveness metrics as presented herein.
13. The incremental ratepayer increase for the addition of the SNCR option is $0.00041/kWh, an average increase of about 0.23 percent. For a family that uses 500 kWh/month, the addition of SNCR would cost $0.21/month and $2.46/year.

Based on the multiple reasons indicated above, the Department has determined the NO_x BART emission limit for Healy 1 to be the equivalent of the existing LNB/OFA system with a new SNCR system; however, the Department has set the NOx emission limit at 0.20 lb/MMBtu rather than 0.19 lb/MMBtu. This determination is based on consideration of all elements of the BART 5-step evaluation process, including the general cost acceptability ($/ton and $/dV); the proximity of Healy 1 to DNPP; the additional reduction in NO_x emissions; and related predicted visibility improvement at DNPP necessary for the Department to meet the reasonable progress compliance goals by 2064.

8.2 SO_2 Control at Healy Unit 1

Table 8-2 presents a comparison matrix of the GVEA-evaluated SO_2 control options as they relate to the BART 5-step control review process. The cost effectiveness information is based on an 8-year remaining useful lifetime of Healy 1 as referenced from the projected SIP required retrofit control implementation date of calendar year 2016 (i.e., end date of calendar year 2024). As discussed in Section 6 of this document, the BART rule does support the use of the 8-year lifetime period for the amortization of capital control costs.

Table 8-2: Comparison Matrix of the GVEA-Evaluated SO_2 Control Options as they Relate to the BART 5-Step Evaluation Process

Control Option	BART Analysis Steps				
	Identify All Control Options (Step 1)	Eliminate Technically Infeasible Options (Step 2)	Evaluation of Control Effectiveness[2] (Step 3)	Cost-Effectiveness and Impacts Analysis[3] (Step 4)	Visibility Impact Evaluation[4] (Step 5)
Existing Dry[1] FGD System (Sodium Bicarbonate Sorbent)	Option Identified	Option Accepted	0% (0.30 lb/MMBtu)	N/A	N/A
Optimize Existing FGD System by Increasing Sorbent Injection	Option Identified	Option Accepted	40% (0.18 lb/MMBtu; 179 add'l tons SO_2 removed)	\$4,218/ton SO_2 (annual) \$4,218/ton SO_2 (incremental) \$3,015,208/deciview	0.250 deciview improvement; 39 day improvement
Install Lime Spray Dryer Semi-Dry FGD System	Option Identified	Option Accepted	50% (0.15 lb/MMBtu; 223 add'l tons SO_2 removed)	\$9,337/ton SO_2 (annual) \$29,813/ton SO_2 (incremental) -\$2,397,400/deciview	-0.870 deciview improvement; 20 day improvement
Install Wet Limestone FGD System	Option Identified	Option Accepted	77% (0.07 lb/MMBtu; 343 add'l tons SO_2 removed)	\$10,275/ton SO_2 (annual) \$12,033/ton SO_2 (incremental) -\$3,033,847/deciview	-1.160 deciview improvement; 18 day improvement

Notes:

(1) The existing controlled SO_2 baseline emission rate is 0.30 lb/MMBtu (30-day average). No effectiveness, capital or operating costs, or visibility improvements are applicable to this existing control scenario.

(2) Percent control (%) is relative to the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system. The SO_2 emission limit corresponding to the option; and the additional amount of SO_2 removed (tons/year) for this control scenario versus existing baseline is also shown.

(3) Cost-effectiveness estimates based on 8-year Healy 1 remaining useful lifetime. Negative values (\$/dV) for lime spray dryer and wet FGD reflects a worsening (i.e., increase) in maximum predicted visibility impacts compared to baseline.

(4) Visibility impacts for each option are relative to existing baseline conditions.

Review of NPS survey data (i.e., Appendix A) for all EGUs indicates respective median and mean SO_2 cost effectiveness values of \$1379/ton and \$1721/ton; and about \$14.5 million/dv and \$10.5 million/dv. While the Department has considered similar data for relatively comparable small EGUs (<100 MW), the general paucity of small affected units does not make such information meaningful for comparison Healy 1 (i.e., there are only four EGUs in the NPS survey data with capacities less than 100 MW, with median and mean cost effectiveness values of about \$5000/ton).

The Department has determined the following with respect to final SO_2 BART for Healy 1.

1. Due to the high cost effectiveness values (\$/ton) presented in Table 8-2, the installation of a wet limestone FGD on Healy 1 is not considered economically feasible. In addition, a new lime spray dryer FGD system also presents excessively high cost per ton values, including the incremental cost.

2. In addition to the relatively high costs associated with the wet FGD and lime spray dryer FGD options, both the wet and dry retrofits are predicted to increase visibility impairment at DNPP due to a cooler, reduced plume.
3. The increased sorbent injection option shows an insignificant predicted improvement in visibility at DNPP. The cost for this option is within the dollar per deciview ($/dv) metric for all EGUs as cited above; but it is about 2.5 to 3 times greater than the median and mean values ($/ton) indicated above. Further, a disparity exists when comparing the almost same NO_x and SO_2 cost effectiveness values. The final recommended NO_x BART option (emission limit equivalent to SNCR) has a cost effectiveness of $4,208/ton, with a coincident significant predicted visibility improvement of 0.620 dv; however, a similar SO_2 cost effectiveness for the optimized FGD option ($4,218/ton) results in only a 0.25 dv predicted improvement in visibility. The Department believes this cost disparity supports the NO_x control; but does not support the optimization SO_2 control option.
4. The increased sorbent injection option will result in the increased potential for visibility impairing brown plume.

Based on the multiple reasons indicated above, the Department has determined that final SO_2 BART for Healy 1 is the current FGD configuration and no additional controls are recommended for the Healy 1 boiler to reduce SO_2 emissions. The emission limit equivalent to the existing FGD system will be set by the Department as the BART emission limit for SO_2.

8.3 Particulate Control at Healy Unit 1

A baghouse is considered the state-of-the-art filterable particulate emissions control technology for utility boiler applications. Therefore, the existing high-efficiency reverse gas baghouse installed on Healy Unit 1 is considered BART. The particulate emission limit for Healy 1 (see Section 9) is reflective of filterable particulate matter (see related discussion, Section 3.3).

9. GVEA BART CONTROL ANALYSIS REPORT FINDINGS AND CONCLUSIONS

The objective of this review has been to document Enviroplan's findings regarding GVEA's BART control analysis. Enviroplan initially conducted a review of the July 2008 BART control analysis to determine compliance with 18 AAC 50.260(e) through (h). The July 2008 report was revised and resubmitted by GVEA in January 2009; GVEA provided additional relevant supplemental information on March 18, 24 and 30, 2009; and Enviroplan prepared a findings report containing a proposed preliminary BART determination for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j). The April 27, 2009 findings report concluded that the GVEA BART control analysis complied with 18 AAC 50.260(e) through (h); and it proposed BART for Healy 1 as the existing dry sorbent injection system (SO_2); the addition of a SCR system (NO_x); and the existing reverse gas baghouse system (PM_{10}). For Auxiliary Boiler #1, the existing configuration (i.e., no air pollution control systems) was determined as BART.

The Department noticed the April 27, 2009 Findings Report and proposed BART determination for the Healy plant. The notice period occurred from May 12, 2009 through June 15, 2009. Comments received were addressed in a RTC document. This report provides the recommended final BART determination for the Healy plant pursuant to 18 AAC 50.260(l), taking into account as necessary the comments and additional information received during the comment period. There is no change in the final BART determination for Auxiliary Boiler #1 (i.e., no controls; current TV permit emission limitations including equivalent limitations in units of lb/MMBtu), and the final BART determination for Healy 1 was presented in Section 8.

9.1 BART Emission Limits

The final BART emission limits recommended for Healy Unit 1 in accordance with 18 AAC 50.260(l) are summarized in Table 9-1 below. As discussed herein, the BART emission limits are based on an 8-year remaining useful life for Healy 1 (from calendar year 2016) which is provided for at Section IV.D.4.K of 40 CFR 51, Appendix Y. The BART emission limits are compared to current permitted pollutant emission limits which remain in effect.

Table 9-1: Final BART Emission Limits Recommended for the GVEA Healy Power Plant

	Particulate		**SO_2**		**NOx**	
	Current [1]	BART [2]	Current [1]	BART [2]	Current [1]	BART [2]
Healy Unit 1	0.05 gr/dscf 36.7 lb/hr (hourly average at full load) 161 ton/yr	0.015 lb/MMBtu (based on compliance source testing)	258 lb/hr (24-hour average, calendar day) 367 lb/hr (3-hour average) 472 ton/yr	0.30 lb/MMBtu (30-day rolling average) [3]	429 ton/yr	0.20 lb/MMBtu (30-day rolling average)
Auxiliary Boiler #1	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average 1 ton per calendar year	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average	0.3% S in oil, annual average 0.5% S in oil, 3-hour average	0.53 lb/MMBtu (30-day rolling average)	20 lb NOx/1000 gal distillate fuel, annual average 20% load factor, annual average	0.15 lb/MMBtu (30-day rolling average).

1. Taken from Permit No. 173TVP01, Table 2.
2. BART emission limits for Unit 1 are in addition to the current (existing) emission limits. The BART emission limit for particulate reflects filterable PM_{10}.

The recommended BART emission limits of Table 9-1 are reflective of the vendor/test-based limits provided by GVEA. This notwithstanding, as indicated in the April 27, 2009 findings report, GVEA requested on March 18, 2009 that their BART emission limits be revised to account for potential operating variability. GVEA conducted an analysis of 2003-2008 (5 years) 30-day rolling NO_x and SO_2 emissions from Healy Unit 1. GVEA applied three standard deviations to the mean, and requested that their BART emission limits reflect the resultant rates at three standard deviations. Given the long-term nature of the NO_x and SO_2 emissions averaging period (30-days); and the fact that the emission limits provided by GVEA are mean values which inherently account for variability, Enviroplan believes that the Table 9-1 BART emission limits will adequately account for any short-term upset or malfunction conditions. Therefore, no change has been made to the GVEA emission limits.

The existing (current) emission limits shown in Table 9-1 were established pursuant to regulatory requirements other than the BART rule. For example, the SO_2 limits of 258 lb/hr (24-hour average) and 367 lb/hr (3-hour average) were established to protect the short-term SO_2 air quality standards. Part 71 Permit AQ0173TVP01 provides the basis for each of the existing emission limits. While the existing short-term emission limits for PM_{10} and SO_2 are larger than the 24-hour average emission rates used by GVEA in the visibility impact modeling (i.e., 6.29 and 182.2 lb/hr, respectively), BART emission limits are prescribed on a mass per heat input basis and a 30-day rolling basis for SO_2 and NOx per 40 CFR 51, Appendix Y, Section V. Therefore, the proposed preliminary BART emission limits presented in Table 9-1 are not intended to replace the existing pollutant emission limits.

9.2 Compliance Demonstration

Consistent with 18 AAC 50.260(l) and 40 CFR 71.6(a)(3), monitoring, record-keeping, and reporting (MR&R) conditions needed to demonstrate compliance with the BART emission limits must be established. The following summarizes the recommended MR&R requirements relating to the BART emission limits of Table 9-1. As appropriate, these conditions are consistent with requirements already contained in the Part 71 operating permit for the Healy Power Plant.

<u>Healy Unit 1:</u>

1. The Permittee shall limit NOx, SO_2 and PM_{10} emissions from EU ID 1 in accordance with the BART limits indicated in Table 9-1.

    1.1 The Permittee shall demonstrate compliance with the NO_X, SO_2 and PM_{10} emission limits for EU ID 1 as follows:

    a. Use continuous emission monitors to determine emissions of NO_X and SO_2 from EU ID 1.

    i. Monitor, record and report in accordance with Conditions 1.2 and 1.3.

    b. Use source test results to determine emissions of PM_{10} from EU ID 1.

    i. Monitor, record and report in accordance with Condition 1.4.

    1.2 In accordance with Condition 1.1a and the Part 71 operating permit for this stationary source, the Permittee shall install and operate a continuous emission monitoring system on the EU ID 1 boiler exhaust duct to measure and record the sulfur dioxide and oxides of nitrogen emissions discharged to the atmosphere.

    a. Monitor, record , and report in accordance with Condition 1.3.

    b. Submit a Quality Assurance Plan to the Department for the continuous emission monitoring system in accordance with the Part 71 operating permit for this stationary source.

    c. Comply with the applicable Performance Specification set out in Title 40 Code of Federal Regulations Part 60, Appendix B, in accordance with the Part 71 operating permit for this stationary source.

    1.3 In accordance with Condition 1.2a and the Part 71 operating permit for this stationary source, the Permittee shall monitor, record and report the following information:

    a. Measure and record the 60-minute average emission rate of NO_x. Record for each operating date the average daily NO_x emission rate (in lb/MMBtu). Determine compliance with the NOx emission limit of Table 9-1 by calculating the arithmetic average of all hourly emission rates from EU ID 1 for NOx for the 30 successive boiler operating days, except for data obtained during startup, shutdown and malfunction or emergency conditions. Record all instances of startup, shutdown and malfunction or emergency conditions occurring during each 30-day rolling averaging period.

b. Measure and record the 60-minute average emission rate of SO_2. Record for each operating date the average daily SO_2 emission rate (in lb/MMBtu). Determine compliance with the SO_2 emission limit of Table 9-1 by calculating the arithmetic average of all hourly emission rates from EU ID 1 for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown and malfunction or emergency conditions. Record all instances of startup, shutdown and malfunction or emergency conditions occurring during each 30-day rolling averaging period.

c. Measure and record the 60-minute average stack gas concentration of oxygen or carbon dioxide.

d. Measure and record the 60-minute average coal feed rate to EU ID 1.

e. Report for each operating day, the average daily NOx and SO2 emission rates (lb/MMBtu); the 30-day rolling average NOx and SO2 emission rates (lb/MMBtu); and the amount of coal combusted (tons).

f. Submit an initial compliance status report within six months of the final BART emission limit compliance date established by the Department.

g. Submit a report in accordance with the *Excess Emissions and Permit Deviations* condition of the Part 71 operating permit whenever the 30-day rolling average NOx or SO_2 emission rate (lb/MMBtu) exceeds the respective allowable rate in Table 9-1.

1.4 In accordance with Condition 1.1b and the Part 71 operating permit for this stationary source, the Permittee shall demonstrate compliance with the PM_{10} emission limit in Table 9-1 as follows:

a. Conduct source tests for particulate matter (PM_{10}) as follows:

i. Conduct the tests and report the results in accordance with the *General Source Testing and Monitoring Requirements* section of the Part 71 operating permit for source emissions testing of $PM_{10.}$ For tests required under Condition 1.4a.ii, submit a test plan at least 60 days before the deadline for the next test under Condition 1.4a.ii;

ii. Conduct an initial test on EU ID 1 within six months of the final BART emission limit compliance date established by the Department;

iii. Conduct additional tests on EU ID 1 within 8760 operating hours of the previous test;

iv. During each test, measure and record baghouse minimum and maximum one-minute pressure drops. Submit the records with the source test report.

b. Comply with the monitoring, recordkeeping and reporting requirements of the Permittee's Compliance Assurance Monitoring (CAM) Plan for particulate emissions from EU ID1 for the monitoring of baghouse pressure differential.

Auxiliary Boiler #1:

2. The Permittee shall limit NOx, SO_2 and PM_{10} emissions for Auxiliary Boiler #1 in accordance with the BART limits indicated in Table 9-1.

2.1 The Permittee shall demonstrate compliance with the NO_X, SO_2 and PM_{10} emission limits for Auxiliary Boiler #1 as follows:

a. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **Visible Emissions Monitoring, Recordkeeping and Reporting** requirements.

b. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **PM Monitoring, Recordkeeping and Reporting** requirements.

c. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **Sulfur Compound Emissions Standards Requirements.**

d. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the requirements for **BACT, Owner Requested Limits, and Other Title I Permit Requirements**, as applicable to EU ID 3.

Appendix A: NOx and SO2 Statistical Data Summaries of Western U.S. EGU BART Determinations As Derived from the NPS August 2009 Survey Data

Table A1: All EGUs Summarized by the NPS Regardless of Unit Capacity or Type					
NOx Summary Statistics for	**BART at**	**46**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	330	367	790	25	16,875
Presumptive BART limit (lb/mmBtu)	0.23	0.25	0.45	0.10	
Reductions (tpy)	1,607	2,794	12,297	0	125,711
Capital Cost	$9,350,000	$13,776,426	$136,800,000	$0	$606,162,750
Capital Cost ($/kW)	$25	$48	$415	$0	
Total Annual Cost	$1,144,944	$2,423,510	$15,682,702	$0	$106,634,441
Cost-Effectiveness ($/ton)	$785	$1,215	$3,778	$0	
Proposed BART Limit	0.24	0.24	0.43	0.07	
Units	lb/mmBtu	Lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.322	0.413	2.668	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$6,211,484	**$8,964,942**	$34,726,950	$1,141,933	
Visibility Improvement (dv at Summed Class I)	0.627	1.021	5.300	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$2,515,268	$4,845,809	$15,329,818	$600,126	

Table A2: All EGUs Between 0 – 110 MW Capacity					
NOx Summary Statistics for	**BART at**	**10**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	98	92	113	55	917
Presumptive BART limit (lb/mmBtu)	0.39	0.39	0.39	0.39	
Reductions (tpy)	357	565	1,443	91	5,653
Capital Cost	$1,946,000	$3,481,270	$7,884,900	$790,000	$34,812,700
Capital Cost ($/kW)	$25	$35	$72	$13	
Total Annual Cost	$490,969	$673,959	$1,498,001	$75,000	$6,739,590
Cost-Effectiveness ($/ton)	$1,089	$1,440	$3,040	$413	
Proposed BART Limit	0.20	0.23	0.39	0.12	
Units	Lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.104	0.229	0.630	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$4,829,753	**$6,229,417**	$15,000,000	$2,012,168	
Visibility Improvement (dv at Summed Class I)	0.019	0.019	0.023	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,233,957	$5,233,957	$7,159,091	$3,308,824	

Table A3: All EGUs Up to 100 MW Capacity					
NOx Summary Statistics for	**BART at**	**5**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	83	72	85	55	361
Presumptive BART limit (lb/mmBtu)	0.39	0.39	0.39	0.39	
Reductions (tpy)	165	178	254	91	889
Capital Cost	$1,820,000	$1,587,600	$2,156,000	$790,000	$7,938,000
Capital Cost ($/kW)	$25	$22	$33	$13	
Total Annual Cost	$276,611	$285,930	$574,613	$75,000	$1,429,649
Cost-Effectiveness ($/ton)	$2,415	$1,776	$3,040	$413	
Proposed BART Limit	0.19	0.25	0.39	0.12	
Units	Lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.024	0.032	0.063	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$10,260,946	**$9,872,122**	$15,000,000	$6,250,000	
Visibility Improvement (dv at Summed Class I)	0.019	0.019	0.023	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,233,957	$5,233,957	$7,159,091	$3,308,824	

Table A4: All EGUs Summarized by the NPS Regardless of Unit Capacity or Type					
SO2 Summary Statistics	**BART at**	**32**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	408	377	690	60	12,063
Presumptive BART limit (lb/mmBtu)	0.15	0.15	0.15	0.15	
Reductions (tpy)	5,657	11,668	64,465	233	361,703
Capital Cost	$41,083,000	$64,838,994	$247,300,000	$1,600,000	$1,815,491,833
Capital Cost ($/kW)	$173	$249	$737	$3	
Total Annual Cost	$8,315,432	$10,459,005	$36,600,000	$366,000	$313,770,152
Cost-Effectiveness ($/ton)	$1,379	$1,721	$7,309	$49	
Proposed BART Limit	0.15	0.19	0.60	0.09	
Units	lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.772	0.751	1.745	0.124	
Cost-Effectiveness ($/98th % dv at Max Class I)	$14,533,679	**$19,264,719**	$49,919,355	$3,600,000	
Visibility Improvement (dv at Summed Class I)	1.954	2.949	10.590	0.000	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,944,587	$5,768,730	$8,008,511	$3,456,091	

Table A5: All EGUs Up to 100 MW Capacity					
SO2 Summary Statistics	**BART at**	**4**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	75	74	85	60	295
Presumptive BART limit (lb/mmBtu)	0.15	0.15	0.15	0.15	
Reductions (tpy)	1,201	1,380	2,238	880	5,519
Capital Cost	$38,000,000	$33,289,333	$46,360,000	$15,508,000	$99,868,000
Capital Cost ($/kW)	$447	$424	$618	$207	
Total Annual Cost	$6,190,000	$4,871,333	$6,556,000	$1,868,000	$14,614,000
Cost-Effectiveness ($/ton)	$5,300	$5,125	$7,309	$2,765	
Proposed BART Limit	0.35	0.36	0.60	0.15	
Units	lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.187	0.187	0.250	0.124	
Cost-Effectiveness ($/98th % dv at Max Class I)	$38,071,677	**$38,071,677**	$49,919,355	$26,224,000	
Visibility Improvement (dv at Summed Class I)	0.000	0.000	0.000	0.000	
Cost-Effectiveness ($/98th % dv at Summed Class I)	#NUM!	#DIV/0!	$0	$0	

Appendix B: Calpuff Visibility Modeling of GVEA Auxiliary Boiler #1 Using Corrected NOx and SO2 Emissions Data

March 26, 2010
Project No. 209928.01

To: Tom Turner, ADEC, DAQ
Alan Schuler, P.E., ADEC, DAQ

From: Michael Hirtler, Enviroplan Consulting
Ganesh Srinivasan, Enviroplan Consulting

Re: NTP: 18-3001-17-8F
Calpuff Visibility Modeling of GVEA Auxiliary Boiler #1

In accordance with the Department's March 17, 2010 email request on the above referenced project, Enviroplan Consulting conducted a visibility impact modeling assessment of the GVEA Healy Power Plant Auxiliary #1 Boiler. The purpose of this analysis is to determine whether the existing Auxiliary Boiler #1, as a BART eligible unit, exceeds the 0.5 deciview visibility significance metric when the unit is modeled with correct NO_x/SO_2 emission rates.

GVEA submitted an Informal Review Request to the Department on February 24, 2010. Among other issues raised in the Request, GVEA disclosed that Auxiliary #1 Boiler NO_x and SO_2 emission rates, as indicated in the GVEA BART Final Determination Report (February 5, 2010), were each understated by a factor of 1000. These emission rates are consistent with those used by WRAP-RMC in their BART visibility modeling screening analysis; and GVEA used these understated emissions in their BART visibility impact analysis for this boiler. As such, the Department requested Enviroplan to re-model Auxiliary #1 Boiler with the corrected boiler NO_x and SO_2 emission rates. The following provides relevant detail pertaining to our visibility impact analysis of Auxiliary #1 Boiler:

- Enviroplan utilized Calpuff version 6.112 (level 060412) and Calpost version 6.131 (level 060410). These are the model versions used by WRAP-RMC and GVEA in their respective modeling evaluations. For purposes of project expediency and consistency, the Department obtained the executable files for each of these programs from GVEA's consultant, CH2M Hill. CH2M Hill also provided the 2002 hourly ozone data recorded at the Denali National Park (DNP) Castnet monitor, which was used by WRAP-RMC in their analysis (i.e., http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calpuff_inps/ak/).
- The Department provided the 2002 Calmet meteorological data file to Enviroplan on external hard-drive. This file was used by GVEA in their modeling evaluation; and Enviroplan used this meteorological data in this analysis.
- Enviroplan used the Calpuff input file for the Auxiliary Boiler #1 baseline scenario, as previously provided to the Department by GVEA (i.e., "healy02.inp"). Enviroplan revised the Auxiliary Boiler #1 NO_x and SO_2 emission rates consistent with those rates specified in the Department's March 16, 2010 Informal Review document (see table below). The particulate emission rate for Auxiliary #1 Boiler in this revised modeling analysis remains unchanged at 0.8 lb/hour (i.e., unchanged from the GVEA/WRAP-RMC modeling).

Auxiliary #1 Boiler Modeled Scenario	SO_2 Modeled Emission Rate (lb/hr)	NOx Modeled Emission Rate (lb/hr)
GVEA Calpuff Analysis*	0.0056	0.0016
Enviroplan Revised Calpuff Analysis	5.6	1.6

*Generally consistent with the WRAP-RMC Calpuff input file for Auxiliary #1 Boiler, except WRAP used pollutant emission rates expressed in units of grams/second (g/s). Converting the above lb/hour emission rates to equivalent g/s results in relatively low numbers that were reflected in the WRAP Calpuff input file as zero NO_x/SO_2 emission rates for this unit.

- Aside from the emission rate revisions indicated above, Enviroplan used all Calpuff model option settings established by GVEA (based on GVEA's use of the WRAP visibility modeling protocol).
- Enviroplan used the Calpost input file for the Auxiliary #1 Boiler baseline scenario, as previously provided to the Department by GVEA (i.e., "caldena.inp"). Except for the Input Group 1 parameter, **NDRECP**, Enviroplan did not alter any model option setting or input parameter established by GVEA (based on GVEA's use of the WRAP visibility modeling protocol). The revision to **NDRECP** is discussed in more detail below.
- The DNP modeling receptor grid used by GVEA (and WRAP) in their modeling analysis was developed by the National Park Service. While GVEA correctly predicted Calpuff pollutant concentrations at all 1367 receptors, they inadvertently omitted the first 776 receptors of the full 1367 receptor listing from their Calpost analysis. As such, Enviroplan corrected GVEA's Calpost **NDRECP** option to include all 1367 receptors in the revised Auxiliary #1 Boiler visibility modeling. The revised results presented above reflect all 1367 DNP receptors.

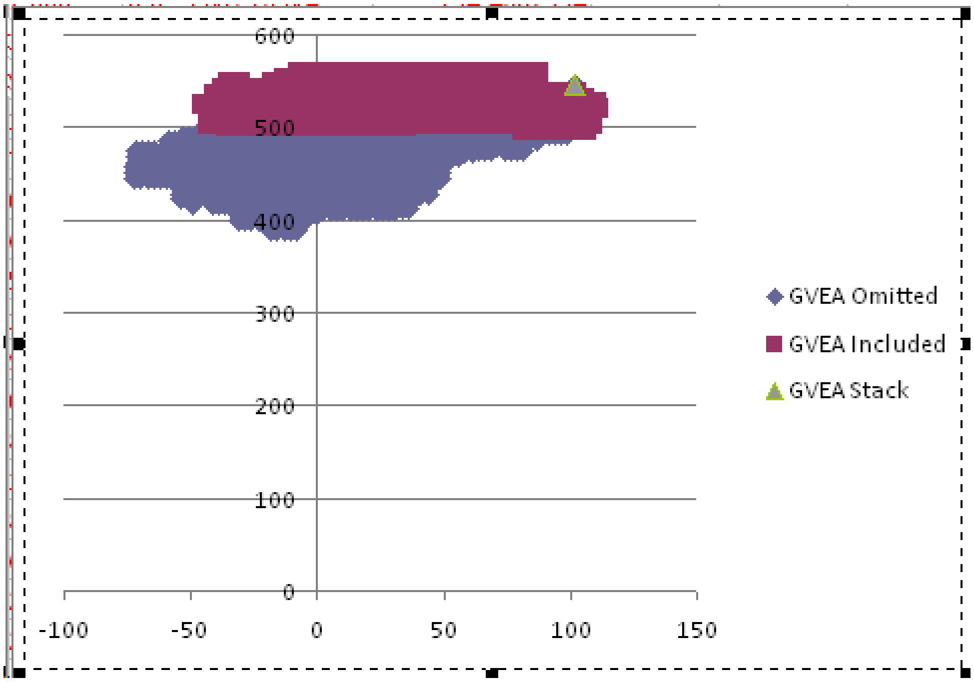
Based on the information described above, Enviroplan determined the revised maximum visibility impact (daily delta deciview, dv) attributable to Auxiliary #1 Boiler. The following presents a comparative summary of the Auxiliary #1 Boiler visibility prediction results:

Auxiliary #1 Boiler Modeled Scenario	Maximum Predicted Visibility Change (Daily Delta-Deciview) (dv)	Significant Change in Visibility* (dv)
GVEA Calpuff Analysis	0.067	0.5
Enviroplan Revised Calpuff Analysis	0.158	0.5

*18 AAC 50.260(q)(4)

The maximum modeled visibility impact associated with Auxiliary #1 Boiler using corrected maximum NO_x and SO_2 emission rates continues to show this emission unit is not predicted to cause or contribute to visibility impairment at DNP.

It is noted that the Auxiliary #1 Boiler revised maximum visibility impact presented above occurred at a location included in GVEA's visibility modeling analysis. Therefore, the revised maximum impact is attributable solely to the corrected unit NO_x and SO_2 emission rates. The 776 previously omitted receptors are relatively distant from the Healy Power Station, and the 591 receptors initially modeled by GVEA are located in relatively close proximity to the plant and remain the dominant receptors in this analysis. The figure below shows the locations of these groups of receptors relative to the Healy Power Station.



While this analysis has focused on GVEA's Auxiliary #1 Boiler, GVEA's omission of the 776 receptors may affect their prior visibility modeling for Healy Unit 1. GVEA omitted the same 776 receptors from the Healy Unit 1 Calpost input files. As such, Enviroplan conducted revised Calpuff/Calpost modeling of Healy Unit 1. The analysis was limited to the GVEA Healy 1 baseline configuration (i.e., maximum daily NO_x, SO_2 and PM emission rates) scenario. Enviroplan corrected GVEA's Calpost **NDRECP** option to include all 1367 receptors; and no other changes were made to GVEA modeling files.

GVEA previously predicted the maximum visibility impact of Healy 1 (591 receptors) to be 3.359 dv. (see GVEA's January 2009 BART determination report; and Sections 7.4 and 8.1 of the GVEA BART Final Determination Report). For the full 1367 DNP receptor grid, Enviroplan determined the maximum visibility impairment attributable to Healy 1 to be unchanged at 3.359 dv.