State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Tier II Operating Permit No. T2-2009.0105 Project 61426

Final

The Amalgamated Sugar Company LLC (TASCO)

Nampa Factory

Nampa, Idaho

Facility ID No. 027-00010

September 19, 2014

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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations for non-carcinogens
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FGD	flue gas desulfurization
HAP	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
LNB	coal-firing low NO_x burners
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
OFA	over-fired air
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration
RH SIP	Regional Haze State Implementation Plan
Rules	Rules for the Control of Air Pollution in Idaho
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/hr	tons per hour
T/yr	tons per year
T2	Tier II operating permit
TAP	toxic air pollutant
TASCO	The Amalgamated Sugar Company LLC
ULNB	ultra-low NO_x burner
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
Δdv	change in delta deciviews

FACILITY INFORMATION

Facility Description

The Amalgamated Sugar Company LLC (TASCO) – Nampa Factory is a beet sugar manufacturing plant.

Permitting Action, Scope, and Chronology

This permit is a Tier II operating permit (T2) for an existing facility. This T2 revises emission standards established for best available retrofit technologies (BART) and revises the initial BART determinations, approves a BART Alternative, and revises associated monitoring, recordkeeping, and reporting requirements.

This permit is not effective until a revised Regional Haze State Implementation Plan (RH SIP) is approved by the U.S. Environmental Protection Agency (EPA) which incorporates BART requirements from this permit. Upon the effective date of a revised RH SIP, this permit supersedes Tier II Operating Permit No. T2-2009.0105 issued on September 7, 2010.

A chronology of events related to the revised and initial BART permitting actions is provided in Table 1 and Table 2, respectively. Refer to the current Tier I permit statement of basis for a history of other permitting actions related to this facility.

Table 1 CHRONOLOGY OF REVISED BART

Date	Description
T2-2009.0105 Project 61426 and 60867	
October 12, 2010	TASCO filed a contested case petition seeking review of permit T2-2009.0105.
November 9, 2010	DEQ met with TASCO to discuss possible revisions to BART and BART Alternative determinations.
December 13, 2010	DEQ met with TASCO to discuss preliminary modeling results for revised BART and BART Alternative.
January 2 – February 25, 2011	DEQ received modeling input information to refine BART and BART Alternative modeling results.
January 11, 2011	EPA proposed approval and promulgation of the regional haze SIP.
March 17, 2011	DEQ met with TASCO to discuss refined modeling results for revised BART and BART Alternative.
April 12 – 14, 2011	DEQ and TASCO confirmed items necessary to complete an application to revise permit T2-2009.0105 and Idaho's Regional Haze State Implementation Plan (RH SIP).
May 4, 2011	DEQ received an application to revise permit T2-2009.0105 and the RH SIP.
May 20, 2011	DEQ received supplemental information, including evaluation of over-fired air feasibility and SCR cost.
June 1, 2011	DEQ determined that the application was complete.
June 3 – 6, 2011	DEQ sent copies of the complete application to the EPA, FLM, and affected states for review.
June 22, 2011	EPA partially approved the RH SIP.
June 28, 2011	DEQ met with FLM to discuss the application.
June 29 – July 20, 2011	DEQ performed additional modeling and requested additional information from TASCO to respond to FLM comments.
August 5, 2011	DEQ received supplemental information, including boiler design information.
August 22 – August 26, 2011	DEQ made available the draft permit and statement of basis for peer review.
August 22, 2011	TASCO filed a petition for review of the RH SIP BART approval.
August 26 – September 16, 2011	DEQ made available the draft permit and statement of basis for facility review.
September 7, 2011	DEQ received modeling input information to confirm Riley Boiler natural gas-fired modeling scenario.
September 15 – 20, 2011	DEQ received comments from TASCO concerning the draft permit and statement of basis, and baseline CO emission rate information on the boilers in their existing configurations.
September 28 – 29, 2011	DEQ provided an updated draft permit and met with TASCO to discuss comments.
October 19, 2011	DEQ provided an updated draft permit and supporting documents to FLM and TASCO.
October 21, 2011	DEQ met with FLM to provide modeling results and respond to questions and comments concerning the application.
October 31, 2011	DEQ notified EPA, FLM, affected states, and interested parties of the public comment period on the proposed action.
October 31 – November 30, 2011	DEQ provided a public comment period on the proposed action.
December 23, 2011	DEQ issued the final permit and statement of basis, and a response to public comments. (Final approval of BART and BART Alternative pending revision of the regional haze SIP.)
September 19, 2014	DEQ issued a typographical correction to T2-2009.0105.

Table 2 CHRONOLOGY OF INITIAL BART

Date	Description
T2-2009.0105	
July 31, 2006	DEQ notified TASCO that each of the Nampa, Twin Falls, and Mini-Cassia facilities had a boiler considered to be BART-eligible.
December 14, 2006	DEQ notified TASCO that each facility had a boiler considered to be subject to BART based upon preliminary modeling analyses.
August 31, 2006 – March 2008	DEQ received several communications from TASCO which provided revised emission data and supporting documentation.
August 31, 2006 – July 21, 2009	DEQ received several communications from TASCO which included concerns regarding BART technical analyses. DEQ responded to concerns and provided supporting information, and informed TASCO that the option was available to submit alternate analyses.
February 23, 2007	DEQ provided revised modeling analyses to TASCO, which indicated that the Nampa facility was subject to BART and that the Twin Falls and Mini-Cassia facilities were not subject to BART
June 17, 2007	DEQ notified TASCO that the Riley Boiler was a BART-eligible source and subject to BART.
July 19, 2007	DEQ notified TASCO that the Riley Boiler was determined to be subject-to-BART and provided the subject-to-BART determination.
July 24, 2007	DEQ sent copies of BART exemption modeling to the EPA and FLM for review.
November 20, 2007	DEQ received a BART determination analysis report from TASCO for the Riley Boiler. DEQ sent a letter to TASCO requesting review of additional control technologies and requesting information supporting the claim of financial hardship and the technically infeasibility of certain control technologies.
December 24, 2007	DEQ received a letter from TASCO including a claim of financial hardship.
September 16, 2008	DEQ provided TASCO the results of modeling analyses for BART alternative control strategies, and requested that TASCO provide DEQ with any BART alternatives for consideration which could achieve greater improvements.
February 9, 2009	DEQ received a revised BART determination analysis report from TASCO which included additional feasible control technologies.
March 11 – May 13, 2009	DEQ requested and received guidance from EPA concerning evaluation of the claim of financial hardship.
June 17, 2009	DEQ sent a letter to TASCO requesting financial information in order to evaluate the claim of financial hardship.
July 1, 2009	DEQ met with TASCO to discuss BART alternatives and extended the deadline for providing supporting financial information.
July 3, 2009	DEQ sent a letter to TASCO addressing questions concerning the subject-to-BART modeling analyses.
July 17, 2009	DEQ notified TASCO of the control technology selection and provided the BART determination analyses.
July 21, 2009	DEQ received financial information from TASCO with a claim of confidentiality.
August 18, 2009	DEQ made available the draft permit and statement of basis for peer and Boise Regional Office review.
August 21, 2009	DEQ made available the draft permit and statement of basis to TASCO for facility review.
August 25, 2009	DEQ received a communication from TASCO requesting that facility review of the draft permit and statement of basis be postponed until the claim of financial hardship had been evaluated.
August 28, 2009	DEQ sent an email to TASCO approving the postponement of the facility review period for the draft permit and statement of basis.
September 10, 2009	DEQ was informed by TASCO that financial information could be released to EPA concerning the claim of confidentiality.
October 9, 2009	DEQ met with EPA and TASCO to discuss the claim of financial hardship.
November 5, 2009	DEQ met with EPA and TASCO to review the financial information submitted and to request additional information.
November 18, 2009	DEQ received supplemental BART determination information from TASCO.
February 22 – March 14, 2010	DEQ was provided a financial analysis and supporting information from EPA Region X which indicated that BART was affordable based upon the financial information provided.
March 17, 2010	DEQ notified TASCO that it had been determined that BART was affordable and provided the financial analysis and supporting information.
March 26, 2010	DEQ made available a revised draft permit and statement of basis for facility review.
April 1, 2010	DEQ sent a letter to TASCO responding to concerns identified in the BART determination letter dated November 18, 2009, and addressing financial hardship, modeling, and emissions reduction crediting concerns.
April 6, 2010	DEQ received comments from TASCO concerning the draft permit and statement of basis. Specific comments relevant to the selected BART control options were addressed.
April 19 – May 19, 2010	DEQ provided a public comment period on the proposed Tier II operating permit and BART determination.
May 19, 2010	DEQ received comments from TASCO concerning the draft permit and statement of basis.
September 7, 2010	DEQ issued Tier II Operating Permit No. T2-2009.0105.

TECHNICAL ANALYSES

Overview of Changes

Table 3 provides summary descriptions of the emission sources and control equipment relevant to the revised BART determinations and the BART Alternative. A summary of the revisions to the initial BART Tier II operating permit and supporting analyses follows, and updated documentation of the complete revised BART determinations and of the approved BART Alternative incorporating the revisions discussed below is provided in Appendix A.

Table 3 BART AND BART ALTERNATIVE EMISSION POINT SOURCES

Source Description		Control Equipment Descriptions	
Riley Boiler (S-B3)		Baghouse (A-B3)	
		Manufacturer:	Envirotech Corp.
Installation Date:	1969	Control efficiency:	≥99.0% for PM (BART for PM)
Rated steam capacity:	250,000 lb steam/hr		
Maximum capacity:	350 MMBTU/hr		
Maximum operation:	8,760 hr/yr	Coal-Firing LNB	
Fuel types:	coal, natural gas	Control efficiency:	≥60.7% for NO_x (BART for NO_x)
B&W Boiler #1 (S-B1)		Coal-Firing LNB	
Installation Date:	1942	Control efficiency:	≥55% for NO_x (BART Alternative for SO_2)
Rated steam capacity:	105,000 lb steam/hr		
Maximum capacity:	126 MMBTU/hr		
Maximum operation:	8,760 hr/yr		
Fuel types:	coal, natural gas		
B&W Boiler #2 (S-B2)		Coal-Firing LNB	
Installation Date:	1942	Control efficiency:	≥55% for NO_x (BART Alternative for SO_2)
Rated steam capacity:	105,000 lb steam/hr		
Maximum capacity:	126 MMBTU/hr		
Maximum operation:	8,760 hr/yr		
Fuel types:	coal, natural gas		
Pulp Dryers (S-D1, S-D2, and S-D3)		Permanent shutdown	(BART Alternative for SO_2)

BART for the control of NO_x

- Following the initial BART determination, it was determined that SCR is not technically feasible for retrofit on the Riley Boiler. Selective catalytic reduction (SCR) is a post-combustion control device that reduces thermal and fuel NO_x emissions with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen.
- Following the initial BART determination, it was determined that incorporating over-fired air as part of a coal-fired low NO_x burner system (LNB) is not technically feasible for retrofit on the Riley Boiler. Low NO_x burners with over-fired air (LNB with OFA) utilize fuel and air mixing optimization and/or staged combustion techniques to reduce thermal NO_x formation.
- Following the initial BART determination, a coal-fired low NO_x burner system (LNB) has been determined to be BART for the control of NO_x emissions from the Riley Boiler. Low NO_x burners (without over-fired air) utilize fuel and air mixing optimization and/or staged combustion techniques to reduce thermal NO_x formation.
- Although considered initially as a BART alternative to the control of NO_x emissions, the shutdown of three coal-fired pulp dryers has instead been included as part of the BART Alternative to the control of SO_2 emissions.

BART Alternative to the control of SO_2

- The shutdown of three coal-fired pulp dryers and the retrofit of coal-fired low NO_x burner systems (LNB) on two B&W Boilers have been proposed as part of a BART Alternative to the control of SO_2 emissions from the Riley Boiler. The Pulp Dryer shutdowns will eliminate NO_x, PM, and SO_2 emissions from the pulp dryers, while LNB will reduce NO_x emissions from the boilers. These controls are predicted to result in greater visibility improvement to Class I areas within 300 km of the facility than the BART determination for SO_2 (Spray Dry FGD), which remains unchanged from the initial BART determination.

  For spray dry flue gas desulfurization (Spray Dry FGD), the flue gas is introduced into a tower and contacts an atomized spray of lime slurry, which absorbs and neutralizes SO_2. (The permittee has documented concerns regarding the affordability and environmental impacts of Spray Dry FGD;[1] however, for the purposes of this BART determination, Spray Dry FGD was considered feasible. Additional information regarding these concerns is provided in Section 1.5.2 of Appendix A.)

Natural Gas-Fired Operation

- The Riley Boiler was designed to combust coal and/or natural gas fuels. Discussion has been provided supporting why BART control equipment and emission limits were applied exclusively to the coal-fired operating scenario.

Terminology

BART Terminology

- In this document the *initial BART* is defined to mean the initial BART determinations for PM, SO_2, and NO_x that were determined under Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010.
- In this document the *revised BART* is defined to mean the BART determination for NO_x, which is being revised by this permitting action. (The BART for PM and SO_2 have not been revised and remain the same as what was determined under Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010.)

BART Alternative Terminology

- In this document the *"BART Alternative"* scenario is defined to mean the combination of BART for PM (Riley Boiler with the existing baghouse), revised BART for NO_x (Riley Boiler with low NO_x burners), and the BART Alternative to the control of SO_2 (B&W Boilers #1 and #2 with low NO_x burners and the three Pulp Dryers shut down).
- In this document the *"BART"* scenario is defined to mean the combination of BART for PM (Riley Boiler with the existing baghouse), revised BART for NO_x (Riley Boiler with low NO_x burners), and BART for SO_2 (Riley Boiler with Spray Dry FGD), with the addition of the sources affected by the "BART Alternative" scenario: B&W Boilers #1 and #2 and three Pulp Dryers in full operation.
- In this document the *"Alternative Benchmark"* scenario is defined to mean the Riley Boiler with the existing baghouse, B&W Boilers #1 and #2, and the three Pulp Dryers. This scenario allows comparison of both the "BART" and "BART Alternative" scenarios against the same benchmark that includes all of the affected sources.

BART Determinations

Background

In accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.668.02.c, Best Available Retrofit Technology (BART) means an emission 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 an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any

[1] Section 1.5.2 of Attachment #2 to "BART Alternative Submittal & Tier II Application", TASCO, May 4, 2011.

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. (These considerations were included in Step 4 of the BART determinations.)

The BART analyses and determinations followed the five-step process provided in Guidelines for BART Determinations Under the Regional Haze Rule (Appendix Y to Part 51):

1) Identify all retrofit control technologies
2) Eliminate technically infeasible options
3) Evaluate control effectiveness of the remaining control technologies
4) Evaluate the impacts of each remaining control technology (including energy, non-air quality environmental, and cost impacts; and the remaining useful life of the source)
5) Select BART and determine the degree of visibility improvement

SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated in the BART analyses and determinations.

Based on CALPUFF air dispersion modeling results, the Riley Boiler was determined to contribute to visibility impairment at three Class I areas, including the Eagle Cap Wilderness (Oregon), Hells Canyon National Recreation Area (Oregon/Idaho border), and Strawberry Mountain Wilderness (Oregon), primarily during the winter time. A single emission source which is responsible for a one-half (0.5) deciview change or more in any mandatory Class I Federal Area "contributes" to visibility impairment as defined in IDAPA 58.01.01.668.02.b.

As part of the initial and revised BART determinations, modeling analyses were conducted to evaluate visibility impacts at seven Class I areas within a 300 km radius around the Riley Boiler. In addition to the three areas listed above, the analyses included Craters of the Moon National Monument, Jarbidge Wilderness, Sawtooth Wilderness, and Selway-Bitterroot Wilderness.

Table 4 BART DETERMINATIONS [a]

Pollutant[b]	Step 1 Technologies Identified	Step 2 Technically Feasible (Yes/No)	Step 3 Control Level (lb/hr)	 Control Ranking	Step 5 Modeled Impairment Contribution[c] (Days>0.5 Δdv)	Step 6 Most Effective (Yes/No)
PM	Wet ESP	Yes	12.4	1	--[d]	No[d]
	Dry ESP	Yes	12.4	1	--[d]	No[d]
	Enhanced Baghouse	Yes	12.4	1	--[d]	No[d]
	Existing Baghouse	Yes	12.4	1	--[d]	Yes
SO_2	Wet FGD	Yes	26	1	43	No[f]
	Spray Dry FGD	Yes	104	2	51	Yes
	Dry Trona FGD	Yes	183	3	58	No
	Dry Lime FGD	Yes	235	4	66	No
	Low Sulfur Coal	Yes	444	5	90	No
	Base Case[e]	Yes	522	6	127	No
NO_x	SNCR	No[g]	--	--	--	--
	SCR	No[h]	--	--	--	--
	ULNB	No[i]	--	--	--	--
	LNB/OFA	No[j]	--	--	--	--
	LNB	Yes	147	1	60	Yes
	Base Case[e]	Yes	374	2	127	No

(a) This table summarizes each BART determination. The BART determination for NO_x has been revised as described in this section.
(b) SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.
(c) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.
(d) Because the cost of the enhanced baghouse, dry ESP, and wet ESP options were determined to outweigh the improvement, BART was selected based on costs of compliance and the pollution control equipment in use (existing baghouse). Specific modeling of each PM control scenario was not analyzed.
(e) The "Base Case" represents continuous coal-fired operation of the Riley Boiler (without controls).
(f) Wet FGD was not determined to be effective due to non-air quality environmental impacts of compliance related to wastewater treatment.
(g) SNCR was not considered feasible due to concerns that the flue gas would not have adequate residence time to achieve reliable control.
(h) SCR was not considered feasible upstream of the baghouse due to insufficient space necessary to accommodate the control device, in addition to concerns regarding catalyst fouling and erosion. SCR was not considered feasible downstream of the baghouse due to exhaust gas cooling below the effective operating temperature range of the control device.
(i) ULNB was not considered feasible due to concerns that the boiler firebox would not be large enough to accommodate the full burner/flame management system required.
(j) It was determined that insufficient vertical distance is available between the top burner elevation and the furnace nose arch, which is necessary to provide adequate fuel combustion residence time and to accommodate the OFA burner/flame management system.

Revisions

The initial BART determinations made under T2-2009.0105 issued September 19, 2010 have been revised based on engineering design information specific to the Riley Boiler retrofit project. A summary of the revised BART determinations is provided below, followed by a discussion of the specific changes. Additionally, although not considered a change in the initial BART determinations, analyses has been provided for each Riley Boiler fuel operating scenario supporting that BART requirements were considered applicable only when firing coal in the Riley Boiler.

Infeasibility of SCR

As provided in Table 4, based on the results of an engineering design review of the Riley Boiler, it has been determined that selective catalytic reduction (SCR) is not technically feasible for retrofit on the Riley Boiler.[2] SCR was not considered feasible upstream of the baghouse due to insufficient space necessary to accommodate the control device, in addition to concerns regarding catalyst fouling and erosion. SCR was not considered feasible downstream of the baghouse due to exhaust gas cooling below the effective operating temperature range of the control device.

Infeasibility of OFA

As provided in Table 4, based on the results of an engineering design review of the Riley Boiler, it has been determined that over-fired air (OFA) is not technically feasible for retrofit on the Riley Boiler.[3] It was determined that insufficient vertical distance is available between the top burner elevation and the furnace nose arch, which is necessary to provide adequate fuel combustion residence time and to accommodate the OFA burner/flame management system.

As provided in Table 5, LNB is expected to result in the reduction or elimination of 37 days of visibility impairment at Eagle Cap Wilderness - the Class I area showing the greatest impact from the Riley Boiler - over the baseline case of no NO_x controls.

Table 5 NO_X BART VISIBILITY IMPROVEMENT

Eagle Cap Wilderness, OR	Delta-deciview impacts greater than contribution threshold (Δdv>0.5)							
	2003		2004		2005		2003-2005	
	8th highest(a)	Total days(b)	8th highest(a)	Total days(b)	8th highest(a)	Total days(b)	22nd highest(c)	Total days(d)
Base Riley Boiler Scenario (wzl10471)	0.721	15	1.086	41	1.109	41	1.086	97
NOx Control Scenario 1 – LNB (wzl10496)	0.467	7	0.766	25	0.823	28	0.760	60

(a) The 8th highest delta-deciview impact for the calendar year.
(b) Total number of days in the 1-year period that exceeded 0.5 delta deciviews.
(c) The 22nd highest delta-deciview impact for the 3-year period.
(d) Total number of days in the 3-year period that exceeded 0.5 delta deciviews.

Modeling of the revised BART was completed using the same protocol as described in Appendix B (this protocol was also used in the BART modeling analyses for Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010).

BART Alternative

Revisions

Shutdown of the pulp dryers, in combination with installation and operation of LNB on the B&W Boilers, has been proposed as the BART Alternative to the control of SO_2 emissions from the Riley Boiler.

The "BART Alternative" scenario is expected to achieve greater reasonable progress than the "BART" scenario because this scenario results in greater emissions reductions and in greater visibility improvements, as described below.

Although this alternative primarily reduces NO_x emissions, with some reduction in PM and SO_2 emissions also resulting from the pulp dryer shutdowns, the "BART Alternative" scenario is expected to result in greater emission reductions in regional haze pollutants (PM, SO2, and NOx) than the "BART" scenario, and the visibility

2 "New Information on Use of Selective Catalytic Reduction as Riley Boiler BART," TASCO, May 20, 2011; and "Response to July 18, 2011 E-mail Questions," August 5, 2011.

3 "Feasibility Study to Determine Best Suited Combustion Technology to meet BART, TASCO Purchase Order #65276, Nampa Sugar Mill – RPI Contract #100477," Riley Power Inc., May 19, 2011.

improvement at all Class I areas was predicted to be greater for the "BART Alternative" scenario – with the reduction or elimination of 41 additional days expected when compared to the "BART" scenario. A description of the "BART" and "BART Alternative" scenarios that were evaluated is provided in the Overview of Changes section.

The BART alternative in Tier II Operating Permit No. T2-2009.0105 issued September 19, 2010 (which involved shutdown of three pulp dryers in lieu of installing a SCR control technology for the control of NO_x emissions), is no longer under consideration as initially proposed. Shutdown of this equipment has instead been incorporated as part of the new BART Alternative to the control of SO_2 emissions as described above, in lieu of installing Spray Dry FGD on the Riley Boiler.

Emission Reductions

For evaluation of the "BART Alternative" scenario emission reductions, the "BART Alternative" scenario was compared to the "BART" scenario. The "Alternative Benchmark" scenario is included for reference to represent baseline (existing) operating conditions. As provided in the tables below, the "BART Alternative" scenario is expected to result in greater emission reductions in regional haze pollutants (PM, SO_2, and NO_x) than the "BART" scenario. Refer to Appendix A for additional information regarding the emission reduction estimates.

An increase in carbon monoxide (CO) emissions is expected to result from the operation of LNB on the Riley Boiler and the B&W Boilers. The permittee has indicated that a net decrease in CO emissions is expected to result from this project, and that the project is not expected to result in a major modification as defined in 40 CFR 52.21(b)(2). The permittee has committed to providing further documentation to address PSD applicability (or non-applicability) at a later date with a separate submittal and/or permit to construct application (if applicable). CO is not considered a visibility-impairing pollutant, and CO emissions are not expected to affect evaluation of the BART determinations and the BART Alternative.

Table 6 "BART" EMISSION REDUCTIONS

Pollutant[a]	Emission Source	"BART" Emissions lb/hr[b]	"Alternative Benchmark" Emissions lb/hr[c]	Net Emission Reductions lb/hr
PM	Riley Boiler	5.9	12.4	6.5
	B&W Boilers #1 & #2	56.9	56.9	0.0
	North, South, & Center Pulp Dryers	92.7	92.7	0.0
SO_2	Riley Boiler	104.0	522.3	418.3
	B&W Boilers #1 & #2	435.0	435.0	0.0
	North, South, & Center Pulp Dryers	17.9	17.9	0.0
NO_x	Riley Boiler	147.0	373.8	226.8
	B&W Boilers #1 & #2	227.0	227.0	0.0
	North, South, & Center Pulp Dryers	191.2	191.2	0.0
Total		***1,277.6***	***1,929.2***	***651.6***

(a) SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.

(b) "BART" scenario includes the Riley Boiler with BART for the control of PM (with the existing baghouse), with BART for the control of NO_x (LNB), and with BART for the control of SO_2 (Spray Dry FGD); full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. This control scenario represents BART as described in the BART Determinations section.

(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009.

Table 7 "BART ALTERNATIVE" EMISSION REDUCTIONS

Pollutant[a]	Emission Source	"BART Alternative" Emissions lb/hr[b]	"Alternative Benchmark" Emissions lb/hr[c]	Net Emission Reductions lb/hr
PM	Riley Boiler	12.4	12.4	0.0
	B&W Boilers #1 & #2	56.9	56.9	0.0
	North, South, & Center Pulp Dryers	0.0	92.7	92.7
SO_2	Riley Boiler	522.3	522.3	0.0
	B&W Boilers #1 & #2	435.0	435.0	0.0
	North, South, & Center Pulp Dryers	0.0	17.9	17.9
NO_x	Riley Boiler	147.0	373.8	226.8
	B&W Boilers #1 & #2	103.0	227.0	124.0
	North, South, & Center Pulp Dryers	0.0	191.2	191.2
Total		***1,276.6***	***1,929.2***	***652.6***

(a) SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.
(b) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.
(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009.

Visibility Improvements

The *"BART Alternative"* scenario was determined to achieve greater improvement in visibility impairment in Class I areas than the "BART" scenario. Refer to Appendix B for additional information regarding these modeling scenarios.

Based on CALPUFF modeling, the highest modeled visibility impacts were predicted to occur in the Eagle Cap Wilderness Area. The combination of BART for PM, BART for NO_x, and the BART Alternative to SO_2 was predicted to result in a minimum reduction or elimination of 23 days of visibility impairment and an improvement in the 22nd highest visibility impact of 0.101 Δdv at the Eagle Cap Wilderness, when compared to the revised BART (as summarized in Table 8).

Table 8 "BART ALTERNATIVE" VISIBILITY IMPROVEMENT – EAGLE CAP [a]

Control Scenario		22nd Highest Impact (Δdv)	Impairment Contribution (Days >0.5 Δdv)[b]
"BART"[d]	Riley Boiler w/ Baghouse *("Alternative Benchmark")*[c] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	2.201	195
	Riley Boiler w/ Baghouse, Spray Dry FGD, LNB [f] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	1.512	149
	Net Visibility Improvement	*0.689*	*46*
"BART Alternative"[e]	Riley Boiler w/ Baghouse *("Alternative Benchmark")*[c] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	2.201	195
	Riley Boiler w/ Baghouse, LNB [f] B&W Boilers #1 & #2 w/ LNB [f] North, South, Center Pulp Dryers – shutdown	1.411	126
	Net Visibility Improvement	*0.790*	*69*
	Difference in Improvement	***0.101***	***23***

(a) This table compares the modeled visibility impacts for the combined BART determinations and the "BART Alternative" to the "Alternative Benchmark" operating scenario. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.
(b) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.
(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009.
(d) "BART" includes the Riley Boiler with BART for the control of PM, NO_x, and SO_2 (with the existing baghouse, LNB, and Spray Dry FGD), full operation of the B&W Boilers (without LNB), and full operation of the three coal-firing pulp dryers.
(e) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO_2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.
(f) The NOx control efficiency of the Riley Boiler LNBs = 60.7%, and for the B&W Boilers LNBs = 55%.

Similar modeled visibility improvements for the "BART Alternative" scenario were predicted across all of the Class I areas evaluated (as summarized in Table 9). On the balance, visibility improvement at all Class I areas was predicted to be greater for the "BART Alternative" scenario – with the reduction or elimination of 41 additional days expected when compared to the "BART" scenario. The single exception was one additional day of visibility impairment and 22nd highest visibility impact of -0.017 Δdv at the Selway-Bitterroot Wilderness. The modeling results also support that the distribution of emissions with respect to the Class I areas evaluated is not substantially different than under the "BART" scenario.

Table 9 "BART ALTERNATIVE" VISIBILITY IMPROVEMENT [a]

Class I Area[a]	"BART"[b]		"BART Alternative"[c]		Difference in Improvements[d]	
	22nd Highest	Days >0.5 Δdv	22nd Highest	Days >0.5 Δdv	22nd Highest	Days >0.5 Δdv
Eagle Cap Wilderness, OR	1.512	149	1.411	126	*0.101*	*23*
Craters of the Moon National Monument, ID	0.267	4	0.245	3	*0.022*	*1*
Hells Canyon National Recreation Area, ID	1.092	87	1.059	80	*0.033*	*7*
Jarbidge Wilderness, NV	0.256	5	0.234	5	*0.022*	*0*
Sawtooth Wilderness, ID	0.319	6	0.307	6	*0.012*	*0*
Selway-Bitterroot Wilderness, ID	0.281	3	0.298	4	*-0.017*	*-1*
Strawberry Mountain Wilderness, OR	1.076	62	0.917	51	*0.159*	*11*
Total Number of Days		*316*		*275*		*41*

(a) This table compares the modeled visibility impacts for the combined BART determinations and the "BART Alternative" to the "Alternative Benchmark" operating scenario. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated. The Class I areas evaluated were the seven areas within a 300 km radius from the Riley Boiler. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.

(b) "BART" includes the Riley Boiler with BART for the control of PM, NOx, and SO2 (with the existing baghouse, LNB, and Spray Dry FGD), full operation of the B&W Boilers (without LNB), and full operation of the three coal-firing pulp dryers.

(c) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.

(d) Values reported in this column represent the relative difference or improvement of the "BART Alternative" over the "BART" control scenario.

Natural Gas-Fired Operation

The Riley Boiler was designed to combust coal and/or natural gas fuels. While the initial BART determinations were applicable only to coal combustion, supporting discussion was not provided which addressed emissions from natural gas combustion in the Statement of Basis for initial Tier II Operating Permit No. T2-2009.0105. Discussion and supporting information are provided below which support the requirement to operate Riley Boiler BART control equipment only when firing coal in the Riley Boiler. Modeling of fuel operating scenarios was completed using the same protocol as described in Appendix B (this protocol was also used in the BART modeling analyses for Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010).

Comparing the fuel operating scenarios in the table below, coal combustion resulted in higher estimated emissions of visibility-impairing pollutants than natural gas combustion, even when taking into account the emissions reductions resulting from BART control equipment.

Table 10 VISIBILITY-IMPAIRING EMISSIONS BY FUEL

Fuel / Control Scenario	PM lb/hr[a]	SO_2 lb/hr[a]	NO_x lb/hr[a]
Coal-Fired Riley Boiler	12.4	522	374
Coal-Fired Riley Boiler with BART	12.4	104	147
Natural Gas-Fired Riley Boiler	7.7	0.2	99

Comparing the fuel operating scenarios in the tables below, coal combustion also resulted in higher predicted visibility impacts than natural gas combustion, even when taking into account the emissions reductions resulting from BART control equipment.

Table 11 VISIBILITY IMPACTS BY FUEL – EAGLE CAP [(a)]

Fuel / Control Scenario	22nd Highest Impact (Δdv)	Impairment Contribution (Days >0.5 Δdv)[(b)]
Coal-Fired Riley Boiler w/ Baghouse	1.086	97
Coal-Fired Riley Boiler w/ Baghouse, Spray Dry FGD, LNB	0.343	5
Natural Gas-Fired Riley Boiler	0.166	0

(a) This table summarizes modeled visibility impacts for the Riley Boiler with the existing baghouse and coal-fired, the Riley Boiler with BART controls and coal-fired, and for the Riley Boiler natural gas-fired (without controls) operating scenarios; detailed technical information can be found in Appendix A and Appendix B. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.

(b) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.

Table 12 VISIBILITY IMPACTS FOR NATURAL GAS [(a)]

Class I Area[(a)]	Natural Gas	
	22nd Highest	Days >0.5 Δdv
Eagle Cap Wilderness, OR	0.166	0
Craters of the Moon National Monument, ID	0.028	0
Hells Canyon National Recreation Area, ID	0.106	0
Jarbidge Wilderness, NV	0.029	0
Sawtooth Wilderness, ID	0.034	0
Selway-Bitterroot Wilderness, ID	0.028	0
Strawberry Mountain Wilderness, OR	0.099	0
Total Number of Days		***0***

(a) This table summarizes modeled visibility impacts for the natural gas-firing operating scenario for the Riley Boiler; detailed technical information can be found in Appendix A and Appendix B. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated. The Class I areas evaluated were the seven areas within a 300 km radius from the Riley Boiler. SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.

As provided, the emissions and modeled visibility impacts when firing 100% natural gas were predicted to be significantly lower than when firing coal in the Riley Boiler, even when accounting for the use of BART controls. It was therefore considered reasonable to determine the "base case" or "no control" options as BART for the control of PM, SO_2, and NO_x emissions when combusting 100% natural gas. As an operational requirement and for compliance monitoring purposes, monitoring of average daily feed or firing rate and hours of operation per day for each fuel has been required in lieu of complying with explicit BART emission rate limits. (Refer to discussion provided for Permit Condition 3.9 in the Permit Conditions Review section for information concerning these requirements.)

As a result, operation of the Riley Boiler on 100% natural gas after the BART compliance date remains a voluntary "compliance option" in lieu of installing BART and BART Alternative control equipment. Operation of BART and BART Alternative control devices is also not required (if installed) when the Riley Boiler is fired exclusively on natural gas, unless required in another permit for other (non-BART) reasons.

REGULATORY REVIEW

Attainment Designation (40 CFR 81.313)

The facility is located in Canyon County, which is designated as attainment or unclassifiable for PM_{10}, $PM_{2.5}$, CO, NO_2, SO_x, and Ozone. Reference 40 CFR 81.313.

Tier II Operating Permit (IDAPA 58.01.01.401)

An application was submitted requesting a BART Tier II operating permit revision. Therefore this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.400-410.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The operation of BART control equipment is not expected to change Title V applicability or classification of the facility. The facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because it emits or has the potential to emit regulated air pollutants in amounts greater than or equal to major facility thresholds listed in IDAPA 58.01.01.008.10. The applicable requirements contained in this Tier II operating permit will be incorporated into the Tier I operating permit during renewal.

Because the Nampa Factory contains a fossil-fuel fired boiler of more than 250 MMBtu/hr heat input, it has been classified as a designated facility as defined in IDAPA 58.01.01.006.30 and 40 CFR 52.21(b)(1)(i)(a).

PTC, PSD, and NSPS Applicability (IDAPA 58.01.01.201, 40 CFR 52.21, and 40 CFR 60)

An application was submitted requesting a BART Tier II operating permit revision. Therefore the procedures of IDAPA 58.01.01.200-228 were not applicable to this permitting action.

The facility is classified as an existing major stationary source, because the estimated emissions of criteria pollutants and HAP have the potential to exceed major stationary source thresholds. Because the Nampa Factory has a fossil-fuel boiler of more than 250 MMBtu/hr heat input, the boiler house (which includes the Riley Boiler) is a designated facility as defined in IDAPA 58.01.01.006.30 and in 40 CFR 52.21(b)(1)(i)(a), and fugitive emissions are required to be included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

PSD, NSPS, and PTC regulatory applicability potentially resulting from the installation and operation of BART and the BART Alternative have not been evaluated or addressed as part of this permitting action. The permittee has requested that regulatory applicability be addressed prior to the installation and operation due date of July 22, 2016 and in a separate permit to construct permitting action, if applicable. The permittee is encouraged to address any applicable requirements as soon as practicable to allow adequate time for DEQ review and permit processing (if applicable) before July 22, 2016.

Ambient air impact analyses of BART and the BART Alternative has not been required or evaluated for compliance with ambient air quality standards. Although an increase in carbon monoxide (CO) emissions is expected to result from the operation of LNB on the Riley Boiler and the B&W Boilers, the permittee has indicated that a net emission decrease in CO is expected to result from the permanent shutdown of the South Pulp Dryer when combined with the emission increases from the LNBs. The permittee has also indicated that an emission increase of any toxic air pollutant (TAP) is not expected to result from this project. As a result, preconstruction compliance with NAAQS or TAP standards is not expected to be applicable to this project.

NESHAP and MACT Applicability (40 CFR Parts 61 and 63)

The installation and operation of BART and BART Alternative control equipment is not expected to alter the applicability of any affected source regulated by National Emission Standards for Hazardous Air Pollutants (NESHAP) Parts 61 or 63.

CAM Applicability (40 CFR 64)

The installation and operation of BART and BART Alternative control equipment is not expected to alter the applicability of any emissions unit regulated by Compliance Assurance Monitoring (CAM) Part 64.

BART Applicability (40 CFR 51.308 and IDAPA 58.01.01.668)

The Riley Boiler was previously determined to be a BART-eligible source and subject-to-BART (refer to the Statement of Basis for T2-2009.0105 for a discussion of BART eligibility and the subject-to-BART determination). Refer to the BART Determinations section and Appendix A for additional discussion concerning BART and the BART Alternative. Following issuance of this revised Tier II operating permit, EPA approval is required before the revised BART determinations and the BART Alternative are effective in accordance with the requirements of 40 CFR 51, Subpart P.

- The Riley Boiler is a BART-eligible source because it was an existing stationary facility (fossil-fuel fired boiler with heat input of 350 MMBtu/hr, more than 250 MMBtu/hr) that was not in operation prior to August 7, 1962 and was in existence on August 7, 1977 (installed in 1969), having the potential to emit 250 tons per year of air pollutants (PM, SO_2, NO_x, and CO) as defined in 40 CFR 51.301.
- The Riley Boiler was determined to be subject-to-BART and to contribute to visibility impairment at the Eagle Cap Wilderness, Hells Canyon National Recreation Area, and Strawberry Mountain Wilderness mandatory Class I Federal Areas based on CALPUFF modeling, with the 98th percentile highest delta-deciview impact greater than 0.5 over the years 2003-2005.
- DEQ will submit the proposed revisions to BART and the BART Alternative to EPA pursuant to Section §51.308(e) for approval as a revision to the RH SIP following issuance of this permit.

40 CFR 51.308(e) and IDAPA 58.01.01.668 .... BART Regional Haze Requirements

Section §51.308(e) describes the Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment. DEQ must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. The purpose of IDAPA 58.01.01.668 is to implement the BART requirements in 40 CFR 51.308(e).

In accordance with §51.308(e)(1), to address the requirements for BART, DEQ must submit an implementation plan containing the plan elements and include documentation for all required analyses.

Best Available Retrofit Technology (BART) means an emission 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 an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs 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.

In accordance with §51.308(e)(1)(ii)(A) and IDAPA 58.01.01.668.02.c, the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART. In this analysis, DEQ must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use 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. These considerations were included in Step 4 of the BART determinations (refer to Appendix A for discussion of the BART determinations).

In accordance with §51.308(e)(1)(iv) and IDAPA 58.01.01.668.04, each source subject to BART is required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the RH SIP. Permit Condition 3.3 includes this requirement.

In accordance with §51.308(e)(1)(v) and IDAPA 58.01.01.668.05, each source subject to BART is required to maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained. Permit Condition 3.8 includes the requirement of this section.

In accordance with §51.308(e)(2) and IDAPA 58.01.01.668.06, DEQ may approve a BART alternative rather than to require sources subject to BART to install, operate, and maintain BART. The alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such alternative measures, DEQ must submit an implementation plan containing the plan elements and include documentation for all required analyses. Installation and operation of Coal-Firing LNB in the B&W Boilers and shutdown of three coal-fired pulp dryers was proposed by the permittee as a BART Alternative to the control of SO_2 emissions. The resultant emissions reduction and visibility impacts were compared with those that would result from BART for SO_2. Documentation of BART and BART Alternative analyses, including an analysis of BART and the BART Alternative, the associated emission reductions, comparison of the BART Alternative to BART, and a determination that the BART Alternative achieves greater reasonable progress than would be achieved through the installation and operation of BART was included in Section 1.3.4 of Appendix A and in Appendix B. Permit Condition 3.5 includes federally enforceable emission limitations for the BART Alternative. Permit Conditions 3.7, 3.10, and 4.1 include requirements for the installation, operation, and maintenance of Coal-Firing LNB in the B&W Boilers and for shutdown of the coal-fired pulp dryer (BART Alternative to the control of SO_2 emissions).

The permittee proposing a BART alternative must demonstrate that this BART alternative will achieve greater reasonable progress than would be achieved through the installation and operation of BART. Because both the expected visibility improvement and the emissions reductions in visibility-impairing pollutants were greater in the case of the BART Alternative, it is expected that the BART Alternative will achieve greater reasonable progress than would be achieved through the installation and operation of BART for SO_2. Refer to the BART Alternative section for additional information.

The permittee proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation. No revision of the requirement for annual performance testing, which relies upon the use of EPA reference methods for evaluating compliance with BART and BART Alternative emission limits, has been proposed.

Permit Conditions Review

This section describes the permit conditions for this permit. With the exception of permit T2-2009.0105, which will be superseded by this permit upon approval of a revised RH SIP, the requirements of this Tier II operating permit do not contravene any permit conditions in any applicable permits to construct and Tier I and Tier II operating permits (T1-050020, T2-050021, P-030062). The permittee must continue to comply with all applicable permits.

Where substantive changes have been made to permit conditions, the permit conditions that were revised have been cited (in parenthesis) from Tier II Operating Permit No. T2-2009.0105 issued September 19, 2010; the permit has been included in Appendix C for reference. Each instance of the BART compliance date in the permit has also been replaced with July 22, 2016, which is five years from the effective date of the initial approved RH SIP[4] as determined in accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv).

<u>Permit Conditions 1.1, 1.2, 3.1, and 3.2 (Permit Conditions 1.1, 1.2, 3.1, and 3.2 of T2-2009.0105)</u>

These permit conditions explain the purpose of this permitting action and describe the emission sources and control equipment regulated. Information reflects the revised BART determinations, the BART Alternative, and the design, equipment, and operational information presented in the revised BART analyses.

Permit Condition 1.1 requires that this permit is not effective until a revised Regional Haze State Implementation Plan incorporating the revised BART and BART Alternative requirements has been approved by EPA. Tier II Operating Permit No. T2-2009.0105 remains effective until approval has been granted by EPA. Upon approval this permit supersedes Tier II Operating Permit No. T2-2009.0105.

Permit Conditions 1.2 and 3.2 have been revised to include revised BART control equipment information for the Riley Boiler LNB and the B&W Boilers LNB.

Permit Condition 3.1 has been revised to include a description of each of the boilers involved in BART and the BART Alternative.

[4] Approval and Promulgation of Implementation Plans, State of Idaho, Regional Haze State Implementation Plan and Interstate Transport Plan, 76 FR Final 36329-36339, Final, June 22, 2011.

Permit Condition 2.1 (Permit Condition 2.1 of T2-2009.0105)

This permit condition clarifies that compliance with all applicable local, state, and federal rules and regulations is required, in accordance with IDAPA 58.01.01.406.

Permit Condition 2.2 (Permit Condition 2.2 of T2-2009.0105)

This permit condition incorporates applicable federal requirements into the permit by reference. The intent is that the federal requirement shall govern any conflict with a permit condition referencing a federal requirement.

Permit Condition 2.3 (Permit Condition 2.3 of T2-2009.0105)

This permit condition provides contact information for submittal of required performance test reports, reports, applications, submittals, and other communications to DEQ.

Permit Condition 2.4

This permit condition provides approved test methods to be used when performance testing is required, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.157.

The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing in accordance with the performance testing general provision (General Provision 6).

Permit Condition 3.3 (Permit Condition 3.3 of T2-2009.0105)

This permit condition incorporates the BART and BART Alternative compliance deadlines in accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv). Coal may be combusted in the Riley Boiler on and after the compliance deadline only if BART and the BART Alternative are installed and operating.

The permittee has requested the option to use BART Alternative control strategies to achieve the BART and BART Alternative emission limits (Permit Conditions 3.4 and 3.5), and has requested the addition of clarifying language which documents that the conditions of this permit may be revised in accordance with IDAPA 58.01.01.404. DEQ has included language in Permit Condition 3.3 inclusive of either using the approved BART and the BART Alternative, or some other DEQ-and-EPA-approved BART alternative(s). Additional BART alternative(s) will be considered and relevant BART determinations revised if adequate time is allowed to meet applicable permitting and SIP deadlines.

This permit condition has been revised to allow for operation using natural gas-only in lieu of installation and operation of BART and BART Alternative control equipment (refer to the Riley Boiler fuel operating scenarios in the BART Determinations section for additional discussion).

As provided in the Natural Gas-Fired Operation section, operation of the Riley Boiler on 100% natural gas after the BART compliance date remains a voluntary "compliance option" in lieu of installing BART and BART Alternative control equipment. Operation of BART and BART Alternative control devices is also not required (if installed) when the Riley Boiler is fired exclusively on natural gas.

Compliance with the deadline (or alternatively, compliance with firing only natural gas in the Riley Boiler as specified in Permit Condition 3.9) is ensured by complying with notification requirements (Permit Condition 3.16).

(Refer to discussion provided concerning Riley Boiler fuel operating scenarios in the BART Determinations section and discussion provided for Permit Conditions 3.6, 3.7, and 3.9 for additional information.)

Permit Conditions 3.4 and 3.5 (Permit Condition 3.4 of T2-2009.0105)

These permit conditions establish revised emission limits for BART and the BART Alternative in accordance with IDAPA 58.01.01.668 and 40 CFR 51.308(e).

The BART PM emission limit was based upon the use of the existing baghouse on Riley Boiler to control PM emissions. The BART and the BART Alternative NO_x emission limits were based upon the use of coal-fired low NO_x burner systems on the Riley Boiler and B&W Boilers to control NO_x emissions.

This permit condition has been revised to reflect the approved changes to the BART and BART Alternative control equipment, and to separate BART emission limits from the BART Alternative emission limits for clarification and for compliance purposes.

Compliance with these emission limits when firing coal is ensured by complying with performance testing (Permit Conditions 3.11 and 3.13) and associated monitoring, recordkeeping, and reporting requirements (Permit Conditions 3.14 and 3.15). Alternatively, compliance with these emission limits is ensured by firing the boiler with natural gas.

Permit Conditions 3.6 and 3.7 (Permit Conditions 3.6, 3.7, and 3.8 of T2-2009.0105)

These permit conditions incorporate requirements to operate the approved BART and BART Alternative control equipment (as described in Permit Condition 3.2) in accordance with §51.308(e)(1)(iv) and IDAPA 58.01.01.668.04.

Permit Conditions 3.6 and 3.7 have been revised to allow for operation using natural gas only in lieu of installation and operation of BART and BART Alternative control equipment. Permit Condition 3.7 has been revised to require the use of LNB on the B&W Boilers, as approved in the BART Alternative. Because over-fired air is no longer part of BART, and because Spray Dry FGD is no longer part of the BART Alternative, the requirements to install and operate these control technologies have been removed.

Compliance with these requirements is ensured by complying with operating (Permit Conditions 3.6 through 3.9), monitoring and recordkeeping (Permit Condition 3.10), performance testing requirements (Permit Conditions 3.11, 3.13 through 3.15), and reporting requirements (Permit Condition 3.16).

(Refer to discussion provided for Permit Condition 3.3 and 3.9 for additional information.)

Permit Condition 3.8 (Permit Conditions 3.9 and 3.10 of T2-2009.0105)

Permit Condition 3.8 requires that the permittee maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05.

For the low NO_x burners, compliance with this requirement is ensured by complying with O&M monitoring and recordkeeping requirements (Permit Condition 3.10). For the existing baghouse, the permittee has requested ensuring compliance with this requirement by complying with existing baghouse pressure drop monitoring and recordkeeping requirements in Permit Condition 3.9 of Tier II Operating Permit No. T2-050021. As a result, this condition has been removed from the permit and the citation for Permit Condition 3.9 of T2-050021 will be updated during permit renewal to include IDAPA 58.01.01.668.05 and 40 CFR 51.308(e)(1)(v). It should also be noted that the baghouse pressure drop monitoring frequency has been reduced from daily to weekly. With consideration given to the relevant permitting and compliance histories of the boilers, it was considered reasonable to maintain the frequency of monitoring that was previously established. The baghouse O&M manual has been included for review and for reference in Appendix D. (Although outside the scope of this permitting action, BART and other monitoring requirements may need to be revisited during renewal of the Title V permit for the purposes of CAM).

Permit Condition 3.9 of T2-050021:

The permittee shall install, operate, calibrate, and maintain measuring device(s) to continuously monitor the pressure drop across each of the baghouses. The pressure drop shall be recorded once per week while the boilers are in operation. In the event the measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with Facility-wide Condition 2.16.

Permit Condition 3.9

This permit condition limits the Riley Boiler to the combustion of only natural gas in the event that BART and the BART Alternative control equipment have not been installed by the BART compliance deadline.

The permittee has requested ensuring compliance with this requirement by complying with existing fuel monitoring and recordkeeping requirements in Permit Condition 3.8 of Tier II Operating Permit No. T2-050021.

Permit Condition 3.8 of T2-050021:

3.8 The permittee shall monitor and record the following information listed in Permit Conditions 3.8.1-3.8.8 for each boiler. The records shall be maintained in accordance with Facility-wide Condition 2.16.

3.8.1 The average daily coal feed rate in tons per hour.

3.8.2 The coal feed rate for each consecutive 12-month period in tons per year.

3.8.3 The daily hours of operation with coal.

3.8.4 The heat input rate expressed in millions of British thermal units per hour by correlating the coal feed rate with the coal high-heating value.

3.8.5 The average daily gas-firing rate in millions of standard cubic feet per hour.

3.8.6 The natural gas-firing rate for each consecutive 12-month period in millions of standard cubic feet per year.

3.8.7 The daily hours of operation with natural gas.

3.8.8 The fuel type whenever the fuel type is changed. Fuel type in this section means natural gas only, coal only, or the combination of natural gas and coal.

(Refer to discussion provided for Permit Conditions 3.3, 3.6, and 3.7 for additional information.)

<u>Permit Condition 3.10 (Permit Condition 3.13 of T2-2009.0105)</u>

This permit condition requires the development and documentation of operation and maintenance procedures for the operation and maintenance of BART control equipment to ensure compliance with the BART emission limits (Permit Conditions 3.4 and 3.5), maintenance of BART equipment (Permit Condition 3.8), control equipment maintenance and operation (General Provision 2), and manufacturer's specifications.

This permit condition has been revised to reflect the approved changes to the BART and BART Alternative control equipment. Because the installation of Spray Dry FGD and over-fired air are no longer part of the BART and the BART Alternative, the requirements to monitor associated indicators (slurry flow rate, adiabatic approach temperature, over-fired airflow) were no longer applicable and have been removed.

<u>Permit Conditions 3.11 and 3.13 (Permit Conditions 3.14 and 3.15 of T2-2009.0105)</u>

Permit Conditions 3.11 and 3.13 require annual performance testing to determine PM and NO_x emissions from the Riley Boiler, and to determine NO_x emissions from the B&W Boilers to demonstrate compliance with BART and BART Alternative emission limits (Permit Conditions 3.4 and 3.5) in accordance with IDAPA 58.01.01.405.

These permit conditions have been revised to reflect the approved changes to the BART and BART Alternative control equipment. Because the SO_2 emissions limit is no longer included as part of the approved BART and BART Alternative emission limits, the requirements to monitor associated indicators (slurry flow rate, adiabatic approach temperature, over-fired airflow) were no longer applicable and have been removed. Six-month deadlines in which to complete required performance testing were requested to accommodate the seasonal operating schedule of the facility, and to allow for testing during the beet campaign (generally the period of maximum boiler operating loads).

Compliance with these requirements is ensured by complying with test monitoring, recordkeeping, and reporting requirements (Permit Conditions 3.14 and 3.15) and General Provision 6.

To assure compliance with the coal sulfur content used as the baseline for the BART SO_2 determination, the permittee has requested to comply with existing fuel sulfur content requirements in Permit Condition 2.14 and 2.15 of Tier I Operating Permit No. T1-050020. (See additional discussion provided in the Response to Public Comments document for this permit.)

Permit Conditions 2.14 and 2.15 of T1-050020:

2.14 The permittee shall not sell, distribute, use or make available for use, any coal containing greater than 1% sulfur by weight.

2.15 The permittee shall monitor and record the sulfur content of each shipment of coal received by using the following:

- *Obtaining a sulfur analysis certificate from the vendor for each shipment of coal received.*
- *Analyzing, or having analyzed by a contract laboratory, a composite of representative samples taken by the permittee from each shipment of coal received. One composite sample shall be analyzed for every 1,000 tons of coal received. Coal samples shall be collected in accordance with ASTM D2243, and analyzed for sulfur content and British thermal unit rating using ASTM method D3177-75 or D4239-85.*

Permit Condition 3.12 (Permit Condition 3.5 of T2-2009.0105)

Permit Condition 3.12 requires initial performance test(s) to determine CO emissions following installation of boiler LNBs, to verify whether the project has resulted in a PSD major modification as defined in 40 CFR 52.21.

An increase in carbon monoxide (CO) emissions is expected to result from the operation of LNB on the Riley Boiler and the B&W Boilers. The permittee has indicated that a net decrease in CO emissions is expected to result from this project, and that the project is not expected to result in a major modification as defined in 40 CFR 52.21(b)(2). The permittee has committed to providing further documentation to address PSD applicability (or non-applicability) at a later date with a separate submittal and/or permit to construct application (if applicable). Six-month deadlines in which to complete required performance testing were requested to accommodate the seasonal operating schedule of the facility, and to allow for testing during the beet campaign (generally the period of maximum boiler operating loads).

Because CO emissions and regulatory applicability will be determined at a later date, CO emission limits (initially included for PSD avoidance purposes) were removed. Permit Condition 3.12 was included to ensure that emissions data necessary to make this applicability determination will be available within 180 days of startup of the LNBs. The CO emissions from the B&W Boilers and the Riley Boiler remain limited by a combined emissions limit of 159.0 T/yr as required by Permit Condition 3.1 of Tier I Operating Permit No. T1-050020.

For baseline emissions, the permittee has provided performance test data for the Riley Boiler when fired by coal and for the B&W Boilers when fired by coal[5] which may be used (in absence of more suitable data) to determine regulatory applicability.

Permit Condition 3.14 and Permit Condition 3.15 (Permit Conditions 3.16 and 3.17 of T2-2009.0105)

These permit conditions specify testing conditions and require monitoring, recordkeeping, and reporting to ensure compliance with initial and periodic performance testing requirements (Permit Conditions 3.11 through 3.13) and in accordance with IDAPA 58.01.01.157 and General Provision 6.

This permit condition has been revised to reflect the approved changes to the BART and BART Alternative control equipment. Because the BART and BART Alternative control equipment no longer include Spray Dry FGD and over-fired air, the requirements to monitor associated indicators (slurry flow rate, adiabatic approach temperature, over-fired airflow) were no longer applicable and have been removed.

The option to request alternate testing frequencies and to utilize a DEQ-approved calculation methods to measure coal feed rate was included at the request of the permittee.

Permit Condition 3.16 (Permit Condition 3.20 of T2-2009.0105)

This permit condition requires DEQ notification of the method used to disable coal-firing on the Riley Boiler if coal-firing LNBs have not been installed by the BART compliance deadline to ensure compliance with Permit Condition 3.9, and requires notification of the anticipated date of initial startup in accordance with General Provision 5 to ensure compliance with Permit Condition 3.7. Contact information was also included.

Permit Condition 4.1 (Permit Condition 4.1 of T2-2009.0105)

This permit condition requires permanent shutdown of the three pulp dryers to comply with the BART Alternative to the control of SO_2 emissions, in accordance with IDAPA 58.01.01.668.06.

Removed Permit Conditions (Permit Conditions 3.11, 3.12, 3.18, 3.19, 4.2, and 5 of T2-2009.0105)

Permit Conditions 3.11 and 3.12 required monitoring of Spray Dry FGD adiabatic approach temperature to ensure compliance with the BART SO_2 emission limit, and monitoring of primary and over-fired air flow rates to ensure compliance with the BART NO_x emission limit. Because a BART Alternative to the control of SO_2 emissions has been approved in lieu of installation and operation of Spray Dry FGD, and because over-fired air is no longer included as part of the BART determination for the control of NO_x emissions, these monitoring indicator requirements were no longer applicable and have been removed.

Permit Condition 3.18 was established to require submittal of information and preconstruction compliance demonstrations necessary to demonstrate compliance with the requirements of IDAPA 58.01.01.200-228. Although an increase in carbon monoxide (CO) emissions is expected to result from the operation of LNB on the

[5] "Attachment A – Net CO Emissions Reductions & Calculations & October 2009 Boiler CO Emissions Test Report," TASCO, September 15, 2011.

Riley Boiler and the B&W Boilers, the permittee has indicated that a net emission decrease in CO is expected to result from the permanent shutdown of the South Pulp Dryer when combined with the emission increases from the LNBs. The permittee has also indicated that an emission increase of any toxic air pollutant (TAP) is not expected to result from this project. As a result, preconstruction compliance with NAAQS or TAP standards is not expected to be applicable to this project. This requirement was no longer considered necessary and was removed.

Permit Condition 3.19 was established to require submittal of information necessary to address applicable CAM requirements in accordance with 40 CFR 64. The installation and operation of BART and BART Alternative control equipment is not expected to alter the applicability of any emissions unit regulated by Compliance Assurance Monitoring (CAM) Part 64. Because CAM requirements will be determined at the time of Tier I operating permit renewal, this requirement has been removed. Because intervals for monitoring, monitor calibration, and performance testing have been required elsewhere in the permit in accordance with IDAPA 58.01.01.668.06.c (Permit Conditions 3.10, 3.11, 3.13, and 3.14), reference to this citation has also been removed.

Permit Condition 4.2 was established to ensure compliance with Permit Condition 4.1, permanent shutdown of the three pulp dryers. The permittee has demonstrated compliance with this requirement, and has provided documentation that shutdown of the rotary drum dryer system, including the North, Center, and South Pulp Dryers, was completed as of December 22, 2006.[6] As a result, this requirement was no longer considered necessary and was removed.

Permit Condition 5 was a restatement of the emission limits in the permit (Permit Conditions 3.4 and 3.5). This permit condition was determined to be duplicative in nature and has been removed.

PUBLIC COMMENT

A public comment period was made available to the public in accordance with IDAPA 58.01.01.404.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A Response to Public Comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

[6] "Notification of Steam Dryer Project Completion", TASCO, January 31, 2007.

APPENDIX A – BART DETERMINATIONS AND BART ALTERNATIVE

Department of Environmental Quality

Amalgamated Sugar Company (TASCO)
Best Available Retrofit Technology Determinations

Revised December 23, 2011

Amalgamated Sugar Company (TASCO)
Best Available Retrofit Technology Determinations

1.1 BART Background

The 1977 Clean Air Act (CAA) Amendments created Part C of the Act entitled Prevention of Significant Deterioration of Air Quality and includes Sections 160-169. The intent of the Prevention of Significant Deterioration (PSD) provisions is to maintain good air quality in areas that attain the national air quality standards and provide special protections for National Parks Wilderness Areas. Part C is divided into two subparts. Subpart 1 established the initial classification of Class I and Class II areas. Class I areas include: Section 162(a)

> *(1) International Parks,*
>
> *(2) National wilderness areas which exceed 5,000 acres in size,*
>
> *(3) National memorial parks which exceed 5,000 acres in size, and*
>
> *(4) National parks which exceed six thousand acres in size and which are in existence on the date of the enactment of the Clean Air Act Amendments of 1977 shall be Class I areas and may not be redesignated. . .*
>
> *(b) All areas in such State designated . . . as attainment or unclassifiable which are not established as class I under subsection (a) shall be class II areas . . .*

The Class I areas that met this criteria and were in existence on or before 1977 became known as "mandatory class I federal areas." Although states could designate other areas as Class I areas after 1977, PSD and other portions of the Regional Haze Rule focus on those Class I areas in existence on or before 1977.

Based on the classification of an area, the amount of allowable degradation which is from new or modified air pollution sources is determined. In National Parks and other Class I areas smaller amounts of degradation known as "increment" are allowed. The PSD program under Part C, Subpart 1 primarily focuses on emission from 1977 forward and will be further discussed in the chapters on Reasonable Progress and Long Term Strategies.

Visibility is called out much stronger in Part C, Subpart 2 and set the national goal of "the prevention of any future and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution" (CAA Section 169(A). In an effort to remediate the existing impairments to visibility, the Section 169(A)(2)(A) includes "a requirement that each major stationary source which is in existence on the date of enactment of this section, but which has not been in operation for more than fifteen years as of such date, . . .emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area, shall procure, install and operate, as expeditiously as practicable (and maintain thereafter) the best available retrofit technology, as determined by the state."

To carry out Congress' intent to install BART on certain emission sources, EPA promulgated the "Regional Haze Rule" [64 FR 35714 (July 1, 1999)]. These rules were challenged, and on May 24, 2002, the U. S. Court of Appeals for the District of Columbia vacated the Regional Haze Rule and remanded the BART provisions in the Rule. Revisions to the rule were published on July 6, 2005 [70 FR 39104 (July 6, 2005)]. The BART rule can also be found under 40 CFR 51.308(e). As part of the July 6, 2005 rule revisions, EPA published Appendix Y guidance for the implementation of BART. The guidance can be found beginning at 70 FR 39156 (July 6, 2005).

In the spring of 2006, the Department of Environmental Quality (DEQ) went through a negotiated rulemaking process to develop rules for Regional Haze. During this process rules were negotiated for the implementation of BART and Reasonable Progress Goals. These rules pertaining to BART can be found at IDAPA 58.01.01.668. During the negotiated rule making process, it was decided to follow EPA Appendix Y Guidance on the BART determination process but not incorporate the guidance into rule under IDAPA. A threshold of visibility impact of 0.5 deciviews in any Class I Federal Area was established through negotiated rulemaking as "contributing" to visibility impairment.

1.2 BART Process

The BART provision applies to "major stationary sources" from 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires that only sources which were built or in operation during a specific 15-year time interval be subject to BART. The BART provision applies to sources that existed as of the date of the 1977 CAA amendments (that is, August 7, 1977) but which had not been in operation for more than 15 years (that is, not in operation as of August 7, 1962). The first phase of the BART process is developing a list of BART "eligible" facilities which include those major facilities from the 26 identified source categories that have a potential to emit 250 tons per year of any light impairing pollutant.

The CAA requires BART analyses when any source meeting the above description "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any Class I area. In most cases, the determination of whether a facility is causing or contributing to visibility impairment is done through modeling. Any BART-eligible facility with an impact of one deciview is considered "causing" visibility impairment, and in Idaho the threshold for "contributing" to impairment is 0.5 deciviews.[7] Any BART-eligible facility causing or contributing to visibility impairment is BART "subject." BART subject facilities are required to go through a process to determine what if any controls will be required.

1.3 BART Eligibility

The source is *BART-eligible* if it falls into one of 26 sector categories, was built between 1962 and 1977, and annually emits more than 250 tons of a haze-causing pollutant. The Riley Boiler of The Amalgamated Sugar Company, LLC (TASCO) Sugar Plant in Nampa, Idaho has been determined to be BART-eligible. The Boiler is rated at 350 million BTUs per hour which meets the BART criteria as a fossil-fuel boiler of more than 250 million BTUs per hour heat input, was installed in 1969, and was put into service between August 7, 1962 and August 7, 1977.

The Riley Boiler's *Potential to Emit* (PTE) exceeds 250 tons per year (T/yr) for the haze-causing pollutants sulfur dioxide (SO_2, 2,770 T/yr), nitrogen oxide (NO_x, 1,708 T/yr), and particulate matter (PM, 55 T/yr), so this emission unit was eligible for inclusion in the subject-to-BART analysis of visibility impairment in Class I areas. Following this criteria, the Riley Boiler at the Nampa TASCO plant was BART-eligible.

[7] A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions—from pristine to highly-impaired. A deciview is the minimum perceptible change to the human eye.

1.4 BART Subject

The source is *subject to BART* if it is reasonably anticipated to cause or contribute to impairment of visibility in a Class I area. According to the Guidelines for Best Available Retrofit Technology (BART) Determinations contained in 40 CFR Part 51, Appendix Y, a source is considered to contribute to visibility impairment if the modeled 98th percentile change in *deciviews* (delta deciview)—a measure of visibility impairment—is equal to or greater than a contribution threshold of 0.5 deciviews. Although Appendix Y does provide for thresholds less than 0.5 deciviews and cumulative impacts, it was determined through negotiated rulemaking with industry, federal land management agencies, DEQ and the public that the "contribute" threshold for a single source would be established at 0.5 deciviews. (See IDAPA 58.01.01.668.02.b.) As suggested in Appendix Y guidance, the determination was made by modeling.

DEQ used the CALPUFF air dispersion modeling system (version 6.112) to determine if the 0.5 deciview threshold was exceeded by any of the BART-eligible sources in Idaho. The modeling of BART-eligible sources was performed in accordance with the *BART Modeling Protocol*,[8] which was jointly developed by the states of Idaho, Washington, and Oregon. Refer to the *BART Modeling Protocol* for details on the modeling methodology used in this subject-to-BART analysis.

The Idaho DEQ, in cooperation with Washington State Department of Ecology and Oregon Department of Environmental Quality contracted with Geomatrix Consultants to develop CALMET datasets to use for the CALPUFF BART modeling. The CALMET datasets were based on Penn State and National Center of Atmospheric Research Mesoscale Model (MM5) runs performed at University of Washington. There were two CALMET datasets produced--one using 12km mesh size and another using 4 km mesh size.[9]

As part of the contract, Geomatrix Consultants ran METSTAT to quantify the quality of the MM5 files used as the meteorological dataset in CALMET—used in the CALPUFF modeling. METSTAT pairs the MM5 forecasted data with meteorological observations and then performs various statistical manipulations and aggregates the results for output.[10]

Subject-to-BART analysis results for the TASCO Riley Boiler, Nampa are shown in Table 1, which highlights the following two threshold values for BART:

- 8th highest value for each of the years modeled (2003-2005), representing the 98th percentile (8/365 = 0.02) cutoff for delta deciviews in each year.
- 22nd highest value for the entire period from 2003 through 2005, representing the 98th percentile (22/1095 = 0.02) cutoff for delta deciviews over three years.

The determining criterion for both values is a delta deciview of at least 0.5 deciviews.

[8] Modeling Protocol for Washington, Oregon and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation.

[9] Modeling Protocol for BART CALMET datasets, Idaho Oregon and Washington, Geomatrix Consultants Inc., July 12, 2006.

[10] INITIAL METSTAT REPORT CALMET Fields for BART Idaho, Oregon and Washington, Geomatrix Consultants.

These findings were based on the emission rates and other facility parameters provided by TASCO at the time of the analysis.[11] Based on the CALPUFF modeling analysis, the TASCO Riley Boiler impacted the following Class I areas with the 98th percentile highest delta-deciview impact greater than 0.5 over the years 2003 to 2005:

- Eagle Cap Wilderness, Oregon
- Hells Canyon National Recreation Area, Idaho
- Strawberry Mountain Wilderness, Oregon

Table 1 Visibility Impacts Compared to 20% Best Days Natural Background Condition

Class I Area	Delta-deciview impacts greater than contribution threshold (Δdv>0.5)							
	2003		2004		2005		2003-2005	
	8th highest[(a)]	Total days[(b)]	8th highest[(a)]	Total days[(b)]	8th highest[(a)]	Total days[(b)]	22nd highest[(c)]	Total days[(d)]
Craters of the Moon	0.161	2	0.224	2	0.153	0	0.196	2
Eagle Cap Wilderness, OR	0.87	20	1.355	46	1.302	46	1.325	112
Hells Canyon National Recreation Area, ID	0.772	13	1.031	27	0.9	21	0.936	61
Jarbidge Wilderness, NV	0.151	0	0.198	1	0.201	1	0.179	2
Sawtooth Wilderness, ID	0.239	2	0.294	4	0.265	0	0.271	6
Selway-Bitterroot Wilderness, ID and MT	0.186	0	0.305	1	0.264	2	0.243	3
Strawberry Mountain Wilderness, OR	0.782	12	0.639	13	1.596	31	0.943	56

(a) The 8th highest delta-deciview impact for the calendar year.
(b) Total number of days in the 1-year period that exceeded 0.5 delta deciviews.
(c) The 22nd highest delta-deciview impact for the 3-year period.
(d) Total number of days in the 3-year period that exceeded 0.5 delta deciviews.

In conclusion, the CALPUFF model predicted that emissions from the Riley Boiler at the TASCO Nampa Factory impacted visibility with the 98th percentile highest delta-deciview impact of more than 0.5 deciview on the Class I areas of Eagle Cap Wilderness, OR; Strawberry Mountain Wilderness, OR; and Hells Canyon Wilderness, ID for the years 2003 to 2005, primarily during winter time periods. Eagle Cap Wilderness area had the highest number of days (112 days in three years), with a delta-deciview impact greater than 0.5. The highest one-year 8th high delta-deciview impact (1.596, year 2005) was found in Strawberry Mountain Wilderness.

The major contributors to visibility deterioration from the Riley Boiler of the TASCO Nampa Factory are SO_2 and NO_2, precursors of sulfate and nitrate aerosols formed in winter under conditions of low temperature and high relative humidity. Modeled impacts were greatest when a high-pressure system persisted in the area for three to four days or more, the atmosphere was stagnant with poor dispersion, and the pollutants transported remained relatively undiluted.

The subject-to-BART analysis, which followed the *BART Modeling Protocol,* and additional extensive sensitivity analysis have demonstrated that the Riley Boiler of the TASCO Nampa Factory is subject to BART. TASCO was notified of the subject-to-BART findings by letter on July 19, 2007.

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[11] The delta-deciview impact for each of the Class I areas identified in the Subject-to-BART analysis changed slightly in the final determination process due to refinements in facility parameters such as stack velocities as provided by TASCO.

1.5 BART Determinations

In accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.668.02.c, Best Available Retrofit Technology (BART) means an emission 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 an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs 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. (These considerations were included in Step 4 of the BART determinations.)

BART control equipment was initially determined to be the existing baghouse for the control of PM emissions, a spray dry flue gas desulfurization (FGD) system for the control of SO_2 emissions, and a low NO_x burner system (LNB) with over-fired air for the control of NO_x emissions. BART emission limits, a BART alternative to the control NO_x, and other BART requirements were incorporated in Tier II Operating Permit No. T2-2009.0105, which was issued on September 7, 2010. On October 12, 2010, TASCO filed a contested case petition seeking review of the permit. During negotiations to resolve the contested case, TASCO provided additional information concerning the feasibility of SCR and over-fired air control technologies, requested revision of the initial BART determinations, and proposed a BART Alternative to the Spray Dry FGD control technology. The BART determinations in this document have been updated based on the revised BART determinations and the approved BART Alternative. The specific revisions to BART and to the BART Alternative, along with the supporting technical analyses, regulatory review, and a discussion of the revised permit conditions has been provided in the Statement of Basis to Tier II Operating Permit No. T2-2009.0105, Project 60867.

The initial BART determinations made under T2-2009.0105 issued September 19, 2010 have been revised based on engineering design information specific to the Riley Boiler retrofit project. A summary of the revised BART determinations is provided below.

Table 2 BART DETERMINATIONS [a]

Pollutant[b]	Step 1 Technologies Identified	Step 2 Technically Feasible (Yes/No)	Step 3 Control Level (lb/hr)	Step 3 Control Ranking	Step 5 Modeled Impairment Contribution(c) (Days>0.5 Δdv)	Step 6 Most Effective (Yes/No)
PM	Wet ESP	Yes	12.4	1	--[d]	No[d]
	Dry ESP	Yes	12.4	1	--[d]	No[d]
	Enhanced Baghouse	Yes	12.4	1	--[d]	No[d]
	Existing Baghouse	Yes	12.4	1	--[d]	Yes
SO2	Wet FGD	Yes	26	1	43	No[f]
	Spray Dry FGD	Yes	104	2	51	Yes
	Dry Trona FGD	Yes	183	3	58	No
	Dry Lime FGD	Yes	235	4	66	No
	Low Sulfur Coal	Yes	444	5	90	No
	Base Case[e]	Yes	522	6	127	No
NOx	SNCR	No[g]	--	--	--	--
	SCR	No[h]	--	--	--	--
	ULNB	No[i]	--	--	--	--
	LNB/OFA	No[j]	--	--	--	--
	LNB	Yes	147	1	60	Yes
	Base Case[e]	Yes	374	2	127	No

(a) This table summarizes each BART determination. The BART determination for NOx has been revised as described in this section.
(b) SO_2, NO_x, and PM emissions were the visibility-impairing pollutants evaluated.
(c) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.
(d) Because the cost of the enhanced baghouse, dry ESP, and wet ESP options were determined to outweigh the improvement, BART was selected based on costs of compliance and the pollution control equipment in use (existing baghouse). Specific modeling of each PM control scenario was not analyzed.
(e) The "Base Case" represents continuous coal-fired operation of the Riley Boiler (without controls).
(f) Wet FGD was not determined to be effective due to non-air quality environmental impacts of compliance related to wastewater treatment.
(g) SNCR was not considered feasible due to concerns that the flue gas would not have adequate residence time to achieve reliable control.
(h) SCR was not considered feasible upstream of the baghouse due to insufficient space necessary to accommodate the control device, in addition to concerns regarding catalyst fouling and erosion. SCR was not considered feasible downstream of the baghouse due to exhaust gas cooling below the effective operating temperature range of the control device.
(i) ULNB was not considered feasible due to concerns that the boiler firebox would not be large enough to accommodate the full burner/flame management system required.
(j) It was determined that insufficient vertical distance is available between the top burner elevation and the furnace nose arch, which is necessary to provide adequate fuel combustion residence time and to accommodate the OFA burner/flame management system.

1.5.1 Particulate BART Control Technology Selection

In determining the "best" BART control technology for particulate controls on the Riley Boiler, DEQ used the five steps as described in EPA Appendix Y.

Step 1 – Identify all available retrofit emissions control techniques

In consultation with DEQ, the following particulate control technologies were identified:

- Existing baghouse
- Enhanced baghouse
- Wet Electrostatic Precipitator (Wet ESP)
- Dry Electrostatic Precipitator (Dry ESP)

Step 2 – Determine technically feasible options

In this step, DEQ relied heavily on TASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ reviewed the information as provided below:

Existing Baghouse - The existing baghouse efficiently reduces PM to very low levels. Measured PM emissions are 0.036 lb/MMBTU, well below the previously proposed industrial boiler MACT standard of 0.07 lb/MMBTU. Control efficiencies for baghouses are reported at 99.0 to 99.9%. For this analysis the control efficiency was assumed to be 99% efficient.

Enhanced Baghouse – The addition of a baghouse module could marginally improve the removal efficiency of the existing baghouse. This option would expand the number of modules from four to five resulting in reduced baghouse velocities and pressure drop. Adding another baghouse module to the Riley Boiler baghouse would be difficult and expensive because of physical space limitations near the existing baghouse. PM control efficiency for the additional baghouse was assumed to be 99.0%.

Wet Electrostatic Precipitator – A Wet ESP consists of a series of collection surfaces in the device that removes particulate using an electrical field. The plates are continuously or intermittently cleaned using a circulating water system. Control efficiencies for Wet ESP systems have been reported to be 99.0 to 99.9%. For the purposes of this evaluation, the control efficiency was assumed to be 99%.

Because of physical space limitations, the installation of the Wet ESP will require demolition and the removal of the existing baghouse and installation of the WET ESP in its place. In addition the system will produce saturated vapor conditions in the stack during some operation scenarios. A liner will be needed to be installed in the existing stack to protect the stack from corrosive conditions.

Dry Electrostatic Precipitator – A Dry ESP is very similar in operation to the Wet ESP option considered above. The particulate to be removed is charged in an electric field and attracted to a collection plate. Control efficiencies for Dry ESP system are reported at 99.0 to 99.9% efficient. For this evaluation the control efficiency is assumed to be 99.0%.

This information is summarized in Table 3 below.

Table 3 Technical Feasibility of PM Controls

Pollutant	Technology	Feasibility	Reason Not Feasible
PM	Existing Baghouse	Yes	None
	Enhanced Baghouse	Yes	None
	Wet ESP	Yes	None
	Dry ESP	Yes	None

In conclusion, all particulate technologies identified are technically feasible options for the Riley Boiler.

Step 3 – Evaluate technically feasible options

In this step, all of the technically feasible options were ranked in order of effectiveness of each control technology identified as technically feasible. Control effectiveness was based on manufacture's performance data, engineering estimates, and demonstrated effectiveness of the technology on the Riley Boiler. This data is summarized in Table 4.

Table 4 Evaluation of PM Controls

Pollutant	Control Option	BART Baseline Maximum Emissions (lb/hr)	BART Baseline Annual Average Emissions (T/yr)	Removal Efficiency (%)	Expected Maximum Emissions (lb/hr)	Expected Annual Emissions (T/yr)
PM	Existing Baghouse	12.4	34.5	99.0%	12.4	34.5
	Enhanced Baghouse	12.4	34.5	99.0%	12.4	34.5
	Dry ESP	12.4	34.5	99.0%	12.4	34.5
	Wet ESP	12.4	34.5	99.0%	12.4	34.5

Since all control technologies have the same removal efficiency no single control technology is ranked higher than the other for emissions removal.

Step 4 – Impact analysis

The use of the existing baghouse stands out as the best BART control technology since it will not require additional costs. The existing baghouse has the added environmental benefits of not requiring additional water or electricity. The benefit of adding an additional bag house is so small the benefits are outweighed by the costs. In conclusion, the best BART control technology for particulate is the existing baghouse.

Step 5 – Determine visibility impacts (improvements)

Since all control technologies have the same removal efficiency there was no merit in modeling specifically for the particulate control scenarios.

1.5.2 SO_2 BART Control Technology Selection

In determining the "best" BART control technology for sulfur dioxide (SO_2) controls on the Riley Boiler, DEQ used the five steps as described in EPA Appendix Y.

Step 1 – Identify all available retrofit emissions control techniques

- Low sulfur coal (LSC)
- Wet flue gas desulfurization (FGD)

- Spray dry FGD
- Dry lime FGD
- Dry Trona injection FGD

Step 2 – Determine technically feasible options

In this step, DEQ relied heavily on TASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ reviewed the information as provided below:

Low Sulfur Coal (LSC) – Currently the Nampa plant uses coal that is limited to 1% sulfur by weight to comply with the Rules for Control of Air Pollution in Idaho. The average actual percent sulfur for the baseline period is approximately 0.75%. This option will look at using 0.6% sulfur with an actual reduction of 15%.

Wet Flue Gas Desulfurization (Wet FGD) – A Wet FGD system typically consists of saturated absorber towers located downstream of a particulate control device. The absorbers are usually configured as a flooded tray system or spray tower. Flue gas entering the absorber reacts with slurred limestone or slaked lime to remove SO_2 at the liquid/gas surface boundary. The reaction forms insoluble products or solids that can be further treated with forced oxidation to convert to gypsum which is a marketable by product. The treated flue gas passes through a mist eliminator system to remove water droplets from the flue gas stream. The flue gas leaving the absorber is saturated with water vapor and can present a visible steam plume from the stack.

Wet FGD systems offer one of the highest SO_2 removal efficiencies of the available control technologies with a removal efficiency of 95% or greater. This is also a technology which EPA is heavily invested and supports. The Installation of Wet FGD will require significant modification of the facility. Key site-specific considerations are as follows:

Wet FGD results in saturated stack conditions during periods of Riley only operation (Shared stack operation during beet campaign with the B&W Boiler is not anticipated to result in saturated stack conditions). The resulting condensation formed in the stack is anticipated to have very low pH values that will require installation of a stack liner to protect the integrity of the stack. Condensed vapors will need to be neutralized. Installation of a stack liner is estimated at $2,000,000.

Since Wet FGD is a wet process, it will generate a wastewater stream. The actual wet process is expected to be contained within the Wet FGD system with a slip stream discharged for wastewater treatment.

Spray Dryer Flue Gas Desulfurization (Spray Dry FGD) – Spray Dry FGD consists of a spray dryer reactor to be located between the boiler exhaust and upstream of a particulate removal device (usually an electrostatic precipitator or baghouse). The reactor consists of a spray dryer absorber tower and support equipment. Flue gas is introduced into a vessel and contacts an atomized spray pattern of lime slurry generated by either a set of dual fluid nozzles or a rotary atomizer. The reaction to remove SO_x occurs on lime slurry droplets as they are evaporated from the heat of the flue gas to form a dry particle.

Because the exit temperature of the reactor must be maintained at a set temperature above the adiabatic saturation temperature of the flue gas (controlled by slurry feed rate), the product removed from the system is in dry form. The emission control efficiency of the reactor increases as the exit flue gas temperature approaches the adiabatic saturation temperature of the flue gas. The approach temperature is typically set at 30-40° F above adiabatic saturation temperature (corresponding to removal efficiencies of 90-80% respectively). Recycling fly ash into the lime slurry feed mixture may increase emission control efficiency depending on the chemical characteristics of the ash.

For the purposes of this evaluation a control efficiency of 80% will be assumed (a higher temperature 40°F was assumed to protect the baghouse).

A spray Dry FGD retrofit project would require modifications to the TASCO Nampa facility. The particulate loading to the baghouse would increase as a result of installing a spray dryer. In addition to the ash entering the reactor with flue gas, the spent lime would contribute to overall particulate loading. Approximately 60% of the formed solids are predicted to drop out in the reactor while 40% would be carried to the baghouse for removal. The increase in particulate loading would likely require an additional baghouse module.

The permittee has documented concerns regarding the affordability and environmental impacts of Spray Dry FGD; however, for the purposes of this BART determination, Spray Dry FGD was considered feasible. With regard to affordability, TASCO has provided revised annualized operating cost estimates related to the installation, maintenance, and operation of this technology. With regard to non-air quality environmental impacts, TASCO has identified concerns related to the disposal of byproducts generated in the operation of this technology, and concerns related to the marketability of boiler fly ash for reuse activities.[12]

Dry Lime Injection Flue Gas Desulfurization (Dry Lime FGD) – Dry Lime FGD consists of injecting pulverized lime (milled to less than 10 microns) into the flue gas upstream of the baghouse. The emission control efficiency of a Dry Lime FGD is critically dependent upon:

Particle Size – The smaller the particle size, the greater the surface area for reaction. Lime is milled to less than 10 microns using a ball mill. The smaller size of the particles is also important to avoid downstream depositing of dust in the equipment and ductwork.

Temperatures – Reaction rates increase with increased temperatures of the flue gas.

Flue Gas Mixing – Good lime particle mixing with the flue gas is important to provide uniform distribution of lime reactant in the baghouse.

The control efficiency for DLIFGD is reported to vary between 45 to 55%. For the purposes of this evaluation, the control efficiency is assumed at 55%.

Dry Trona Injection Flue Gas Desulfurization (Dry Trona FGD) – Trona is a naturally occurring source of sodium carbonate that is available from mines in Wyoming. Similar to Dry Lime FGD, Dry Trona FGD consists of injecting pulverized Trona (milled to less than 10 microns) into the flue gas downstream of the existing baghouse and upstream of a new baghouse. The injection system requirements and technical characteristics are very similar to the Dry Lime FGD system discussed above.

The control efficiency for Dry Trona FGD is reported to range between 55 to 65%. For the purposes of this evaluation, the control efficiency is assumed at 65%.

This information is summarized in Table 5, below.

[12] Section 1.5.2 of Attachment #2 to "BART Alternative Submittal & Tier II Application", TASCO, May 4, 2011; and "FW: Attached 2 files for DEQ Emailing…", TASCO, October 27, 2011.

Table 5 Technical Feasibility of SO_2 Controls

Pollutant	Technology	Feasibility	Reason Not Feasible
SO_2	Low Sulfur Coal	Yes	None
	Wet FGD	Yes	None
	Spray Dry FGD	Yes	None
	Dry Lime FGD	Yes	None
	Dry Trona FGD	Yes	None

Step 3 – Evaluate technically feasible options

Based on the control efficiency rates listed above, TASCO determined the baseline maximum hourly emission rates, baseline average annual emission rate, anticipated control efficiency of emission controls, expected maximum hourly emission rate and expected annual emission rates. This data is summarized in Table 6, below.

Table 6 Evaluation of SO_2 Controls

Pollutant	Control Option	BART Baseline Maximum Emissions (lb/hr)	BART Baseline Annual Average Emissions (T/yr)	Removal Efficiency (%)	Expected Maximum Emissions (lb/hr)	Expected Annual Emissions (T/yr)
SO_2	Low Sulfur Coal	522	1457	15%	444	1238
	Dry Lime FGD	522	1457	55%	235	655
	Dry Trona FGD	522	1457	65%	183	510
	Spray Dry FGD	522	1457	80%	104	291
	Wet FGD	522	1457	95%	26	73

Step 4 – Impact analysis

TASCO did a cost evaluation for each of the control technologies analyzed. A complete cost evaluation can be found in Appendix D & E of "*Best Available Retrofit Technology (BART) Determination Analysis, 2009.* These findings were based on EPA fact sheets, engineering and performance test data, and information and discussions with equipment vendors. Table 7 summarizes those results.

Table 7 Impacts of SO_2 Controls

Control Scenario	Baseline Emissions (T/yr)	Removal Efficiency (%)	Annual Emissions Reduction (T/yr)	Total Reduction (T/yr)	Total Capital Cost ($x1,000)	Total Annual Cost ($x1,000)	Cost ($/T)	Incremental Cost ($/T)
Low Sulfur Coal	1,457	15%	219	219	0	$1,024	$4,685	$0
Dry Lime FGD	1,457	55%	801	801	$11,281	$2,687	$3,353	$2,857
Dry Trona FGD	1,457	65%	947	947	$11,281	$2,442	$2,557	-$1,678
Spray Dry FGD	1,457	80%	1,166	1,166	$12,970	$2,521	$2,163	$360
Wet FGD	1,457	95%	1,384	1,384	$22,006	$4,034	$3,353	$6,940

After reviewing TASCO's evaluation, DEQ has concerns with the installation of Wet FGD. In reviewing TASCO's BART Determination Analysis for the Riley Boiler, and specifically looking into wastewater treatment processes associated with Wet Flue Gas Desulfurization (Wet FGD), TASCO's submittal does not present technical specifications or much detail regarding the wastewater treatment process. It's not immediately clear that the costs of the wastewater treatment process are included in the estimates presented in their submittal; however, there appear to be many vendors who provide wastewater treatment processes as part of a Wet FGD project, so it is assumed that the cost of wastewater management is contained within the cost estimates provided for the Wet FGD process itself.

There are several variables that make it very difficult to speculate about the volume of wastewater that might be produced, or any constituent concentrations in wastewater from the process. The source and composition of (1) the coal fired in the boiler, and (2) the limestone used in the Wet FGD process will largely dictate the constituents and constituent concentrations in the wastewater, but there are likely to be significant concentrations of chlorides, fluorides, sulfate, arsenic, mercury, selenium, boron, cadmium, zinc, iron, aluminum, and inert fines that will require some sort of treatment prior to any discharge. Because the wastewater stream is saturated with calcium sulfate (i.e., gypsum), scaling is a major issue with operation and maintenance of process units and piping. The wastewater will also be hot, somewhat acidic, and will have high levels of total dissolved solids. There's also information available that indicates the presence of nitrates in the wastewater. Many of these constituents have primary or secondary quality standards in the *Ground Water Quality Rule*, and any proposal involving land application would almost certainly require impact assessments and/or permitting before DEQ would allow them to go forward.

It is entirely possible to design treatment units to manage and remove the majority of these constituents from the wastewater. The gypsum is a marketable product that would likely be precipitated out of solution and recovered as a commodity. The metals can also be precipitated, although many of these are regulated as hazardous wastes at relatively low concentrations (i.e., the hazardous waste program would probably want to be involved with management of these solids). There are also other processes that can be used to reduce residual levels of dissolved solids and nitrates in the final effluent, although it's important to note that more treatment generally means more cost and more oversight required. The potential volume and quality of the final, treated effluent is very difficult to speculate about without knowing more about the wastewater that will be produced by the Wet FGD process and the treatment processes that will be used to manage that wastewater.

With respect to TASCO's existing wastewater treatment system, the facility is presently treating most of its wastewater on site in an aerated lagoon and sending it to the municipal treatment plant operated by the City of Nampa during off-peak hours. To continue with this operation, a very high degree of wastewater treatment will be required, and substantial improvements to the existing treatment process will almost certainly be required. It would be expected that the city might have concerns about any potential increase in the volume of wastewater discharged to its system. This could mean that the City would need to expand its treatment system or that TASCO might look to land application to manage the new wastewater stream.

TASCO does still have a wastewater land application permit with DEQ, but the facility has only utilized land application for a very small fraction of its total wastewater load in recent years. The company land applied ~12MG in the 2005 season (6% of total WW generated), ~5MG in the 2006 season (3% of total WW generated), ~1MG in the 2007 season (1% of total WW generated), and no wastewater was land applied in the 2008 season. As a result of this reduction in land applied wastewaters, we have seen improving trends in its ground water monitoring wells. Historically, there were issues with nitrates, chlorides, and total dissolved solids concentrations in ground water around the site. While some exceedances of the associated ground water quality standards still exists, most monitoring wells have shown improving trends in ground water quality in recent years, and the DEQ Boise Regional Office is encouraging TASCO to continue to minimize wastewater land application at this time.

Although wastewater treatment processes are available to produce a high-quality effluent that could be successfully land applied under a permit from DEQ, these processes will be fairly complex and expensive, and will likely require dedicated staff to operate and maintain. **Additionally, the reduction in wastewater land application in recent years has improved historic issues with ground water quality that have generally been associated with TASCO's operation**, so any proposal to increase loading rates from a new source of wastewater would require a complete permit application that includes a ground water impact assessment showing no adverse impacts to existing ground water quality. We would issue a permit with enforceable limits and comprehensive monitoring/reporting requirements to ensure protection of ground water quality, assuming that the application and impact assessments can be technically verified and approved.

Step 5 – Determine visibility impacts (improvements)

Table 8 below summarizes the modeling results for SO_2 controls.

Table 8 Visibility Improvement of SO_2 Controls - Change in Visibility Impacts Compared to 20% Best Days Natural Background Condition

Eagle Cap Wilderness, OR	Delta-deciview impacts greater than contribution threshold (Δdv>0.5)							
	2003		2004		2005		2003-2005	
	8th highest[a]	Total days[b]	8th highest[a]	Total days[b]	8th highest[a]	Total days[b]	22nd highest[c]	Total days[d]
Base Riley Boiler Plus Pulp Dryer Full Operation Scenario (wzi10469)	0.956	23	1.454	49	1.388	55	1.399	127
Base Riley Boiler Scenario (wzi10471)	0.721	15	1.086	41	1.109	41	1.086	97
SO_2 Control Scenario 1 Lower Sulfur Coal (wzi10475)	0.682	15	1.016	39	1.028	36	1.014	90
SO_2 Control Scenario 2 Dry Lime Injection (wzi10476)	0.586	9	0.814	28	0.806	29	0.806	66
SO_2 Control Scenario 3 Dry Trona Injection (wzi10477)	0.565	9	0.764	24	0.739	25	0.761	58
SO_2 Control Scenario 4 Spray Dryer FGD (wzi10478)	0.527	9	0.703	22	0.707	20	0.686	51
SO_2 Control Scenario 5 Wet FGD (wzi10479)	0.499	7	0.647	19	0.645	17	0.638	43

a) The 8th highest delta-deciview impact for the calendar year.
b) Total number of days in the 1-year period that exceeded 0.5 delta deciviews.
c) The 22nd highest delta-deciview impact for the 3-year period.
d) Total number of days in the 3-year period that exceeded 0.5 delta deciviews.

Since TASCO believed running the CALPUFF modeling for the various control technology scenarios would be costly, DEQ performed the CALPUFF modeling in-house and invited TASCO to have a contractor review the modeling if deemed necessary. Because each scenario can change the stack velocities and temperatures, it was important that DEQ work closely with TASCO. DEQ worked very closely with TASCO facility engineers to determine the modeling inputs for each of the scenarios.

Conclusion - As part of the impact analysis, non-air quality environmental concerns are to be taken into consideration. Although Wet FGD has a 15% greater removal efficiency over the next closest control of Spray Dry FGD, the potential for reversing the current trend of improvements to ground water due to TASCO land applying outweigh the environmental benefits. TASCO is currently sending pretreated wastewater to the City of Nampa. There is a high likelihood that an increase in TASCO's waste stream would be greater than the city can currently handle. This would more than likely lead to TASCO requesting to increase land application of waste water. For these reasons, DEQ will not be including Wet FGD in the control options even though the technology is technically feasible for improvements in air quality and visibility.

1.5.3 NO_x BART Control Technology Selection

In determining the "best" BART control technology for nitrogen oxides (NO_x) controls on the Riley Boiler, DEQ used the five steps as described in EPA Appendix Y.

Step 1 – Identify all available retrofit emissions control techniques

DEQ in consultation with TASCO identified the following control technologies appropriate for boilers:

- Low NO_x Burners (LNB)
- Low NO_x Burners with Over-fired Air (LNB/OFA)
- Ultra Low NO_x Burners (ULNB)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

Step 2 - Determine technically feasible options

In this step, DEQ relied heavily on TASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ reviewed the information as provided below:

Low NO_x Burners - LNBs incorporate staged fuel or staged combustion air to control the flame temperature of the boiler. Several low NO_x burner systems are available with different levels of cost and performance capabilities. A guaranteed NO_x removal efficiency of 60.7% for the Riley Boiler was provided by the vendor.

Low NO_x Burners with Over-Fired Air – These systems inject a portion of the combustion air downstream of the fuel burner system to lower flame temperatures and the formation of NO_x. Over-fired air as a standalone retrofit technology can be difficult to control causing combustion issues with pulverized coal boiler, including water wall corrosion and reduced boiler efficiencies. When combined with a low NO_x burner and reasonable combustion air control, NO_x removal efficiencies can approach 65%.

In the initial BART determination (as described in the Statement of Basis to Tier II Operating Permit No. T2-2009.0105, issued September 7, 2010), it was determined based on technical analyses that low NO_x burners with over fired air were technically feasible. However, based on the results of an engineering design review of the Riley Boiler, it has subsequently been determined that over fired air (OFA) is not technically feasible for retrofit on the Riley Boiler.[13] It was determined that insufficient vertical distance is available between the top burner elevation and the furnace nose arch, which is necessary to provide adequate fuel combustion residence time and to accommodate the OFA burner/flame management system.

[13] "Feasibility Study to Determine Best Suited Combustion Technology to meet BART, TASCO Purchase Order #65276, Nampa Sugar Mill – RPI Contract #100477," Riley Power Inc., May 19, 2011.

Ultra Low NO_x Burners – These systems are upgraded LNB designs which involve further control and staging of combustion air and fuel. ULNB was determined not technically feasible on the Riley Boiler. The boiler's existing firebox is not large enough to accept the full burner/flame management system required by the ULNB.

Selective Catalytic Reduction – SCR systems reduce NO_x by injecting ammonia and urea into the flue gas before it passes through a catalytic grid to reduce the NO_x to N_2. This technology requires the flue gas exhaust from the Riley baghouse to be heated to 500° C before injecting ammonia or urea and passing the hot gases through the selective catalytic grid. After treatment, heat is recovered in a heat exchanger to minimize operating costs to reheat the flue gas. This technology is capable of reducing NO_x emissions by 70% to 90%. For the purposes of this evaluation a control efficiency of 90% was assumed.

In the initial BART determination (as described in the Statement of Basis to Tier II Operating Permit No. T2-2009.0105, issued September 7, 2010), it was determined that SCR was technically feasible. However, based on the results of an engineering design review of the Riley Boiler, it has subsequently been determined that SCR is not technically feasible for retrofit on the Riley Boiler.[14] SCR was not considered feasible upstream of the baghouse due to insufficient space necessary to accommodate the control device, in addition to concerns regarding catalyst fouling and erosion. SCR was not considered feasible downstream of the baghouse due to exhaust gas cooling below the effective operating temperature range of the control device.

Selective Non-Catalytic Reduction (SNCR) – SNCR consists of injecting ammonia or urea into boiler flue gases in a narrow temperature zone of 1550 to 1950° F. To achieve these temperatures, the injection point must be located between the Riley Boiler economizer and the air pre-heater. The process relies on good gas mixing in the narrow high temperature zone to reduce NO_x to N_2 as the flue gas moves through the ductwork. Boiler load swings can lead to temperature changes at the injection that can significantly reduce removal efficiencies. In addition, injection points can lead to "ammonia slip" or the condition where unreacted ammonia passes through downstream equipment, including the baghouse and discharges from the stack. The gas path for the Riley Boiler lacks the necessary residence time to reliably remove the NO_x. The results of upsets could lead to "ammonia slip."

This information is summarized in Table 9, below.

Table 9 Technical Feasibility of NO_x Controls

Pollutant	Technology	Feasibility	Reason Not Feasible
NO_x	Low NO_x Burners	Yes	None
	Low NO_x with Over-Fired Air	No	Insufficient vertical distance between the top burner elevation and the furnace nose arch to support OFA system.
	Ultra NO_x Low Burners	No	Boiler Firebox is not large enough to support the flame management system.
	Selective Catalytic Reduction	No	Catalyst fouling and erosion, or exhaust temperature too low
	Selective Non-Catalytic Reduction	No	Boiler gas path does not have adequate residence time for reliable control.

[14] "New Information on Use of Selective Catalytic Reduction as Riley Boiler BART," TASCO, May 20, 2011; and "Response to July 18, 2011 E-mail Questions," August 5, 2011.

Step 3 – Evaluate technically feasible options

Based on the control efficiency rates listed above, TASCO determined the baseline maximum hourly emission rates, baseline average annual emission rate, anticipated control efficiency of emission controls, expected maximum hourly emission rate and expected annual emission rates. This data is summarized in Table 10, below.

Table 10 Evaluation of NO_x Controls

Pollutant	Control Option	BART Baseline Maximum Emissions (lb/hr)	BART Baseline Annual Average Emissions (T/yr)	Removal Efficiency (%)	Expected Maximum Emissions (lb/hr)	Expected Annual Emissions (T/yr)
NO_x	Low NO_x Burners	374	1,042	60.7%	147	410

Step 4 – Impact Analysis

The use of low NO_x burners was the top feasible control technology for minimizing NO_x emissions. Control options were not eliminated based on energy, environmental, or economic impacts.

Step 5 – Determine visibility impacts (improvements)

Since TASCO believed running the CALPUFF modeling for the various control technology scenarios would be costly, DEQ performed the CALPUFF modeling in-house and invited TASCO to have a contractor review the modeling if deemed necessary. Because each scenario can change the stack velocities and temperatures, it was important that DEQ work closely with TASCO. DEQ worked very closely with TASCO facility engineers to determine the modeling inputs for each of the scenarios.

Table 11 Visibility Improvement of NO_x Controls – Compared to 20% Best Days Natural Background Condition

Eagle Cap Wilderness, OR	Delta-deciview impacts greater than contribution threshold (Δdv>0.5)							
	2003		2004		2005		2003-2005	
	8th highest(a)	Total days(b)	8th highest(a)	Total days(b)	8th highest(a)	Total days(b)	22nd highest(c)	Total days(d)
Base Riley Boiler Scenario (wzl10471)	0.721	15	1.086	41	1.109	41	1.086	97
NOx Control Scenario 1 – LNB (wzl10496)	0.467	7	0.766	25	0.823	28	0.760	60

(a) The 8th highest delta-deciview impact for the calendar year.

(b) Total number of days in the 1-year period that exceeded 0.5 delta deciviews.

(c) The 22nd highest delta-deciview impact for the 3-year period.

(d) Total number of days in the 3-year period that exceeded 0.5 delta deciviews.

1.5.4 SO_2 BART Alternative

In addition to the control technologies reviewed, TASCO proposed a BART Alternative to provide greater reductions in visibility-impairing emissions and associated modeled visibility impacts than what would be expected with the use of Spray Dry FGD.

For the unique circumstances of this project, BART Alternative NO_x emission limits for the B&W Boilers and shutdown requirements for the pulp dryers were approved in lieu of the SO_2 emission control limits indicated by the BART analyses for SO_2 emissions. These combined measures were predicted to result in greater projected emission reductions and in greater visibility improvement.

As summarized in Table 12, the BART Alternative meets the "better-than-BART test" in accordance with 40 CFR 51.308(e)(3) and as provided in the BART Guidelines (Appendix Y to 40 CFR 51);

- Visibility does not decline in any Class I area, and
- There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

Dispersion modeling was conducted to demonstrate that the BART Alternative will not result in a decline in visibility in any Class I area and will result in an overall improvement in visibility. Supporting information for this determination follows, and can be found in Appendix B.

Table 12 BART ALTERNATIVE
GREATER REASONABLE PROGRESS DETERMINATION

Reasonable Progress Criteria	Benchmark	BART	BART Alternative	"Better-than-Baseline" Improvement	"Better-than-BART" Improvement
Visibility-Impairing Emissions (PM_{10} + NO_x + SO_2) – Rate in lb/hr					*Reductions in lb/hr*
BART Alternative Emission Units	1,929.2	1,277.6	1,276.6	[redacted]	+ 1.0 (a)
Class I Area Visibility – Number of Days Above 0.5 Δdv				*Number of Days Improved to Less Than 0.5 Δdv*	
Eagle Cap	195	149	126	+ 69 (b)	
Craters of the Moon	10	4	3	+ 7 (b)	
Hells Canyon	129	87	80	+ 49 (b)	
Jarbidge	8	5	5	+ 3 (b)	+ 41 (c)
Sawtooth	18	6	6	+ 12 (b)	
Selway-Bitterroot	15	3	4	+ 11 (b)	
Strawberry Mountain	80	62	51	+ 29 (b)	
Result				***No degradation in any Class I area (c)***	***Overall improvement in visibility and Greater Reasonable Progress (a,c)***

(a) BART Alternative results in greater emission reductions as described under 40 CFR 51.308(e)(3).
(b) For the BART Alternative, visibility does not decline in any Class I area, meeting the criteria in 40 CFR 51.308(e)(3)(i).
(c) For the BART Alternative, there is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas, meeting the criteria in 40 CFR 51.308(e)(3)(ii).

BART Terminology

- In this document the *initial BART* is defined to mean the initial BART determinations for PM, SO2, and NOx that were determined under Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010.
- In this document the *revised BART* is defined to mean the BART determination for NOx, which is being revised by this permitting action. (The BART for PM and SO2 have not been revised and remain the same as what was determined under Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010.)

BART Alternative Terminology

- In this document the *"BART Alternative"* scenario is defined to mean the combination of BART for PM (Riley Boiler with the existing baghouse), revised BART for NOx (Riley Boiler with low NOx burners), and the BART Alternative to the control of SO2 (B&W Boilers #1 and #2 with low NOx burners and the three Pulp Dryers shut down).
- In this document the *"BART"* scenario is defined to mean the combination of BART for PM (Riley Boiler with the existing baghouse), revised BART for NOx (Riley Boiler with low NOx burners), and BART for SO2 (Riley Boiler with Spray Dry FGD), with the addition of the sources affected by the "BART Alternative" scenario: B&W Boilers #1 and #2 and three Pulp Dryers in full operation.
- In this document the *"Alternative Benchmark"* scenario is defined to mean the Riley Boiler with the existing baghouse, B&W Boilers #1 and #2, and the three Pulp Dryers. This scenario allows comparison of both the "BART" and "BART Alternative" scenarios against the same benchmark that includes all of the affected sources.

Evaluate emission reductions

TASCO has provided information relating to operational changes at the facility after the regional haze base years of 2000-2004. In 2006, TASCO installed a $20 million new pulp dryer system which better utilized current steam production and allowed three coal-fired pulp dryers to shut down. The pulp drying typically occurs during the fall and winter months when TASCO's emissions show the highest modeled impact on the 20% worst days. A summary of the emission reductions attributed to the shutdown of the pulp dryers is provided in Table 14. As part of the impact and visibility improvements TASCO requested that DEQ evaluate the visibility improvements resulting from the pulp dryer shutdowns and determine that the reductions from the new steam dryers could be used as part of an alternative to BART. Also as part of the BART Alternative, TASCO has proposed the installation and operation of low NOx burners on both of the B&W Boilers. These steps have been proposed as the BART Alternative to the control of sulfur dioxide (SO_2) emissions.

Table 13 "BART" Emission Reductions [a]

Pollutant[a]	Emission Source	"BART" Emissions lb/hr[b]	"Alternative Benchmark" Emissions lb/hr[c]	Net Emission Reductions lb/hr
PM	Riley Boiler	5.9	12.4	6.5
	B&W Boilers #1 & #2	56.9	56.9	0.0
	North, South, & Center Pulp Dryers	92.7	92.7	0.0
SO2	Riley Boiler	104.0	522.3	418.3
	B&W Boilers #1 & #2	435.0	435.0	0.0
	North, South, & Center Pulp Dryers	17.9	17.9	0.0
NOx	Riley Boiler	147.0	373.8	226.8
	B&W Boilers #1 & #2	227.0	227.0	0.0
	North, South, & Center Pulp Dryers	191.2	191.2	0.0
Total		***1,277.6***	***1,929.2***	***651.6***

(a) SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.

(b) "BART" scenario includes the Riley Boiler with BART for the control of PM (with the existing baghouse), with BART for the control of NOx (LNB), and with BART for the control of SO2 (Spray Dry FGD); full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. This control scenario represents BART as described in the BART Determinations section.

(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009.

Table 14 "BART Alternative" Emission Reductions

Pollutant[a]	Emission Source	"BART Alternative" Emissions lb/hr[b]	"Alternative Benchmark" Emissions lb/hr[c]	Net Emission Reductions lb/hr
PM	Riley Boiler	12.4	12.4	0.0
	B&W Boilers #1 & #2	56.9	56.9	0.0
	North, South, & Center Pulp Dryers	0.0	92.7	92.7
SO_2	Riley Boiler	522.3	522.3	0.0
	B&W Boilers #1 & #2	435.0	435.0	0.0
	North, South, & Center Pulp Dryers	0.0	17.9	17.9
NO_x	Riley Boiler	147.0	373.8	226.8
	B&W Boilers #1 & #2	103.0	227.0	124.0
	North, South, & Center Pulp Dryers	0.0	191.2	191.2
Total		***1,276.6***	***1,929.2***	***652.6***

(a) SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.
(b) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.
(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009

For evaluation of the "BART Alternative" scenario emission reductions, the "BART Alternative" scenario was compared to the "BART" scenario in Table 14 and Table 13, respectively. As provided in these tables, the "BART Alternative" scenario is expected to result in greater emission reductions in regional haze pollutants (PM, SO2, and NOx) than the "BART" scenario.

Determine visibility impacts (improvements)

Because each scenario can change the stack velocities and temperatures, DEQ utilized stack parameters and emission rate estimates provided by TASCO. As described above, for comparison each of the emission sources involved in the "BART Alternative" scenario were also included in the other scenarios evaluated.

Table 15 Visibility Improvement of "BART Alternative" Scenario – Eagle Cap [a]

Control Scenario		22nd Highest Impact (Δdv)	Impairment Contribution (Days >0.5 Δdv)[b]
"BART"[d]	Riley Boiler w/ Baghouse *("Alternative Benchmark")*[c] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	2.201	195
	Riley Boiler w/ Baghouse, Spray Dry FGD, LNB [f] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	1.512	149
	Net Visibility Improvement	*0.689*	*46*
"BART Alternative"[e]	Riley Boiler w/ Baghouse *("Alternative Benchmark")*[c] B&W Boilers #1 & #2 – full operation North, South, Center Pulp Dryers – full operation	2.201	195
	Riley Boiler w/ Baghouse, LNB [f] B&W Boilers #1 & #2 w/ LNB [f] North, South, Center Pulp Dryers – shutdown	1.411	126
	Net Visibility Improvement	*0.790*	*69*
	Difference in Improvement	***0.101***	***23***

(a) This table compares the modeled visibility impacts for the combined BART determinations and the "BART Alternative" to the "Alternative Benchmark" operating scenario. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.
(b) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.
(c) "Alternative Benchmark" includes the Riley Boiler (with the existing baghouse), full operation of the B&W Boilers (without LNB), and full operation of the three pulp dryers. Estimated emission reductions attributable to shutdown of the pulp dryers were provided in Table 7 of the BART determination submitted February 9, 2009.
(d) "BART" includes the Riley Boiler with BART for the control of PM, NOx, and SO2 (with the existing baghouse, LNB, and Spray Dry FGD), full operation of the B&W Boilers (without LNB), and full operation of the three coal-firing pulp dryers.
(e) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.
(f) The NOx control efficiency of the Riley Boiler LNBs = 60.7%, and for the B&W Boilers LNBs = 55%.

The "BART Alternative" scenario was determined to achieve greater improvement in visibility impairment in Class I areas than the "BART" scenario. Refer to Appendix B for additional information regarding these modeling scenarios.

Based on CALPUFF modeling, the highest modeled visibility impacts were predicted to occur in the Eagle Cap Wilderness Area. The combination of BART for PM, BART for NOx, and the BART Alternative to SO2 was predicted to result in a minimum reduction or elimination of 23 days of visibility impairment and an improvement in the 22nd highest visibility impact of 0.101 Δdv at the Eagle Cap Wilderness, when compared to the revised BART (as summarized in Table 8).

Table 16 "BART Alternative" Scenario Visibility Improvement

Class I Area[a]	"BART"[b]		"BART Alternative"[c]		Difference in Improvements[d]	
	22nd Highest	Days >0.5 Δdv	22nd Highest	Days >0.5 Δdv	22nd Highest	Days >0.5 Δdv
Eagle Cap Wilderness, OR	1.512	149	1.411	126	*0.101*	*23*
Craters of the Moon National Monument, ID	0.267	4	0.245	3	*0.022*	*1*
Hells Canyon National Recreation Area, ID	1.092	87	1.059	80	*0.033*	*7*
Jarbidge Wilderness, NV	0.256	5	0.234	5	*0.022*	*0*
Sawtooth Wilderness, ID	0.319	6	0.307	6	*0.012*	*0*
Selway-Bitterroot Wilderness, ID	0.281	3	0.298	4	*-0.017*	*-1*
Strawberry Mountain Wilderness, OR	1.076	62	0.917	51	*0.159*	*11*
Total Number of Days		*316*		*275*		*41*

(a) This table compares the modeled visibility impacts for the combined BART determinations and the "BART Alternative" to the "Alternative Benchmark" operating scenario. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated. The Class I areas evaluated were the seven areas within a 300 km radius from the Riley Boiler. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.

(b) "BART" includes the Riley Boiler with BART for the control of PM, NOx, and SO2 (with the existing baghouse, LNB, and Spray Dry FGD), full operation of the B&W Boilers (without LNB), and full operation of the three coal-firing pulp dryers.

(c) "BART Alternative" includes the Riley Boiler with BART for the control of PM (with the existing baghouse) and with BART for the control of NOx (LNB), the B&W Boilers with the BART Alternative to the control of SO2 (Coal-Firing LNB for each boiler), and shutdown of the three coal-firing pulp dryers. This control scenario represents the control equipment described in Permit Condition 3.2.

(d) Values reported in this column represent the relative difference or improvement of the "BART Alternative" over the "BART" control scenario.

The "BART Alternative" scenario is expected to achieve greater reasonable progress than the "BART" scenario because this scenario results in greater emissions reductions and in greater visibility improvements. DEQ is therefore approving the combination of the pulp dryer shutdowns and the installation and operation of low NO_x burners on the B&W Boilers as an alternative to BART for the control of SO_2 emissions (i.e., as an alternative to the installation and operation of Spray Dry FGD).

1.6 Natural Gas-Fired Operation

The Riley Boiler was designed to combust coal and/or natural gas fuels. Discussion and supporting information are provided below which support the requirement to operate Riley Boiler BART control equipment only when firing coal in the Riley Boiler. Modeling of fuel operating scenarios was completed using the same protocol as described in Appendix B (this protocol was also used in the BART modeling analyses for Tier II Operating Permit No. T2-2009.0105, issued on September 19, 2010).

Comparing the fuel operating scenarios in the table below, coal combustion resulted in higher estimated emissions of visibility-impairing pollutants than natural gas combustion, even when taking into account the emissions reductions resulting from BART control equipment.

Comparing the fuel operating scenarios in the tables below, coal combustion also resulted in higher predicted visibility impacts than natural gas combustion, even when taking into account the emissions reductions resulting from BART control equipment.

Table 17 Visibility-Impairing Emissions by Fuel Type

Fuel / Control Scenario	PM lb/hr(a)	SO2 lb/hr(a)	NOx lb/hr(a)
Coal-Fired Riley Boiler	12.4	522	374
Coal-Fired Riley Boiler with BART	12.4	104	147
Natural Gas-Fired Riley Boiler	7.7	0.2	99

Table 18 Visibility Impacts by Fuel Type – Eagle Cap (a)

Fuel / Control Scenario	22nd Highest Impact (Δdv)	Impairment Contribution (Days >0.5 Δdv)(b)
Coal-Fired Riley Boiler w/ Baghouse	1.086	97
Coal-Fired Riley Boiler w/ Baghouse, Spray Dry FGD, LNB	0.343	5
Natural Gas-Fired Riley Boiler	0.166	0

(a) This table summarizes modeled visibility impacts for the Riley Boiler with the existing baghouse and coal-fired, the Riley Boiler with BART controls and coal-fired, and for the Riley Boiler natural gas-fired (without controls) operating scenarios; detailed technical information can be found in Appendix A and Appendix B. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.

(b) Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness Area.

Table 19 Visibility Impacts for Natural Gas (a)

Class I Area(a)	Natural Gas	
	22nd Highest	Days >0.5 Δdv
Eagle Cap Wilderness, OR	0.166	0
Craters of the Moon National Monument, ID	0.028	0
Hells Canyon National Recreation Area, ID	0.106	0
Jarbidge Wilderness, NV	0.029	0
Sawtooth Wilderness, ID	0.034	0
Selway-Bitterroot Wilderness, ID	0.028	0
Strawberry Mountain Wilderness, OR	0.099	0
Total Number of Days		***0***

(a) This table summarizes modeled visibility impacts for the natural gas-firing operating scenario for the Riley Boiler; detailed technical information can be found in Appendix A and Appendix B. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated. The Class I areas evaluated were the seven areas within a 300 km radius from the Riley Boiler. SO2, NOx, and PM emissions were the visibility-impairing pollutants evaluated.

As provided, the emissions and modeled visibility impacts when firing 100% natural gas were predicted to be significantly lower than when firing coal in the Riley Boiler, even when accounting for the use of

BART controls. It was therefore considered reasonable to determine the "base case" or "no control" options as BART for the control of PM, SO2, and NOx emissions when combusting 100% natural gas.

1.7 Conclusion

In conclusion, DEQ approves the "BART Alternative" control scenario – the combination of the existing baghouse and LNB on the Riley Boiler, LNB on both of the B&W Boilers, and shutdown of the three coal-fired pulp dryers – as the "best" of BART technologies. The "BART Alternative" scenario is expected to result in greater emission reductions in regional haze pollutants (PM, SO2, and NOx) than the "BART" scenario, and the visibility improvement at all Class I areas was predicted to be greater for the "BART Alternative" scenario – with the reduction or elimination of 41 additional days expected when compared to the "BART" scenario.

BART and BART Alternative emission limits have been established in Permit Conditions 3.4 and 3.5 of Tier II Operating Permit No. T2-2009.0105 Project 61426. BART and BART Alternative operating, monitoring, compliance testing, recordkeeping, notification, and reporting requirements have been established in Permit Conditions 3.3, 3.6, 3.7, 3.8, 3.10, 3.11, 3.13, 3.14, 3.15, 3.16, and 4.1.

APPENDIX B – BART ALTERNATIVE VISIBILITY MODELING

BART Alternative Visibility Modeling for the Riley Boiler at TASCO – Nampa Factory

State of Idaho
Department of Environmental Quality
1410 North Hilton
Boise, ID 83706

October 19, 2011

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Executive Summary

The Amalgamated Sugar Company LLC (TASCO) has requested a revision to the BART determination for the coal-fired Riley Boiler at their Nampa Factory, and has proposed a BART Alternative. The revised BART includes Spray Dry Flue Gas Desulfurization (Spray Dry FGD) for sulfur dioxide (SO_2) control, Low NO_x burners (LNB) for nitrogen oxides (NO_x) control, and a baghouse for particulate matter (PM) control. The proposed BART Alternative replaces the Spray Dry FGD with a) LNB controls on two (non-BART) Babcock and Wilcox (B&W) boilers, and b) credits SO_2, NO_x and PM emission reductions from shutting down 3 pulp dryers. This report describes new modeling to assess the resulting visibility changes at Class I areas within 300 km of the facility.

The modeling was completed in accordance with the three-state BART Modeling Protocol which underwent an extensive review and approval process and formed the basis for much of the BART modeling conducted in the Pacific Northwest. In order to compare the BART Alternative impacts with the selected BART control scheme on the same basis, both scenarios were modeled with emissions from all the sources included in the BART Alternative; i.e. the pulp dryers and the non-BART B&W Boilers. In this report, the term "BART" (in quotation marks) denotes the selected BART technology for the Riley boiler (LNB) along with emissions from the other emission sources (B&W Boilers and pulp dryers) affected by the alternative in their pre-BART condition.

Model results for the "BART Alternative" scenario indicate that visibility improves an additional 0.159 Δdv on the 22nd highest day at Strawberry Mountain Wilderness and 0.101Δdv at Eagle Cap in comparison to the "BART" scenario. The number of days above 0.5 Δdv is reduced by 11 more days at Strawberry Mountain and 23 more days at Eagle Cap, with a total reduction of 41 more days at all the Class I areas combined over the three-year modeling period.

Although the "BART Alternative" scenario reduces the largest visibility impacts during the winter when both modeled and monitored regional haze impacts were highest, the shift from SO_2 control to additional NO_x control will also result in a slightly greater visibility impairment in the best visibility months of March – June when sulfate dominates the relatively clear air at the Starkey IMPROVE site, representing Eagle Cap and Strawberry Mountain wilderness areas. However, this impairment from the BART Alternative in the non-winter months is small in comparison to the visibility benefits projected in the winter months, and it is clear that the proposed BART Alternative produces greater reductions on more high-impact days than the "BART" scenario, and is therefore a preferred approach for reducing regional haze.

In addition to the greater visibility improvements, the BART Alternative provides greater ozone mitigation benefits by more than doubling the NO_x reductions over those of the "BART" scenario (from 2.7 to 6.5 tons per day). DEQ photochemical modeling indicates that this will rank amongst the top ozone mitigation measures being evaluated in our efforts to mitigate ozone and avoid an ozone non-attainment designation. This is important to the State of Idaho because of the health and economic disadvantages that non-attainment status may bring and the potential restrictions that the region could incur in the areas of industrial growth, transportation improvements, and agricultural and prescribed burning.

Introduction

The Amalgamated Sugar Company LLC (TASCO) at Nampa, Idaho has requested revision of the initial Best Available Retrofit Technology (BART) determination for NO_x and approval of a BART Alternative to control visibility-impairing pollutant emissions from the Riley Boiler at their Nampa Factory. The BART determinations (as revised) include Spray Dry Flue Gas Desulfurization (Spray Dry FGD) for sulfur dioxide (SO_2) control, Low NO_x burners (LNB) for nitrogen oxides (NO_x) control, and a baghouse for particulate matter (PM) control. The proposed BART Alternative replaces the Spray Dry FGD with a) LNB controls on two (non-BART) Babcock and Wilcox (B&W) boilers, and b) SO_2, NO_x and PM emission reduction credits for shutting down 3 pulp dryers. Modeling results documenting the visibility impacts of the revised BART and the proposed BART Alternative along with an Alternative Benchmark scenario are described in this report. The benchmark scenario provides a common pre-BART basis against which the regional haze impacts of both the BART and BART Alternative scenarios can be compared.

Control Scenarios Modeled

The revised BART and BART Alternative determinations are discussed in the Statement of Basis prepared in conjunction with this permitting action. This report addresses the relative differences in regional haze impacts for the modeled control scenarios and the measured patterns of aerosol extinction and visibility degradation at the Class I areas where the impacts occur. The modeling summarized in this memo involves the following scenarios, with computer runs identified by run identification numbers:

"BART" Modeling Scenario

This scenario, (Run ID wzl10495) includes Riley Boiler BART emissions along with benchmark emissions of sources affected by the BART Alternative. Note, BART (without quotation marks) refers to the BART determination control technology involving only the Riley Boiler, while "BART" (with quotations) refers to this modeling scenario, which includes the other affected emission sources:

- Riley Boiler with existing baghouse, Spray Dry FGD, and LNB
- B&W Boilers #1 and #2 (benchmark emissions of sources affected by the BART Alternative)
- Pulp Dryers, full operation (benchmark emissions of sources affected by the BART Alternative)

"BART Alternative" Modeling Scenario

This scenario (Run ID wzl10493) includes the BART NO_x controls on the Riley boiler, along with Low-NO_x burners on two other non-BART Babcock and Wilcox (B&W) boilers. The B&W NO_x controls along with credits for shutting down three pulp dryers, is proposed by TASCO as an alternative for SO_2 control using Spray-Dry FGD.

- Riley Boiler with existing baghouse and LNB
- B&W Boilers #1 and #2 with LNB
- Pulp Dryers shut down (North, Center, South)

"Alternative Benchmark" Modeling Scenario

This scenario (Run ID wzI10492) includes benchmark or pre-BART emissions from the Riley Boiler and the other sources affected by the BART Alternative scenario. It provides a common benchmark for comparison of the "BART" and "BART Alternative" scenarios on an equivalent basis:

- Riley Boiler with existing baghouse
- B&W Boilers #1 and #2, full operation
- Pulp Dryers, full operation

Methods

The dispersion and visibility modeling described in this report is based on stack parameters and emission rates provided by TASCO. The location and stack parameters for all sources involved in the modeling of all scenarios are presented in Table 1 and the emission rates for the same sources are presented in Table 2.

DEQ used the CALPUFF (v 6.112) air dispersion modeling system to determine the delta-deciview (Δdv) visibility impacts, the number of days per year above the 0.5 Δdv threshold, and the number of days per the three–year period above the 0.5 Δdv threshold. The modeling was performed in accordance with the *BART Modeling Protocol*[1], which was jointly developed by the states of Idaho, Washington, and Oregon, and which has undergone public, Federal Land Manager (FLM) and EPA review and approval. This is the identical protocol used for DEQ's *Subject-to-BART* modeling completed in support of the initial BART Tier II operating permit.[2] The meteorological and CALPUFF computational domains for the Nampa Factory are shown in Figure 1 along with the source location (red dot) and the Class I areas (red with black outlines) within 300 km of the source. Class I areas included in this analysis and identifying abbreviations used in Figure 1 are shown in Table 1. The Class I areas are primarily wilderness areas managed by the United States Forest Service, with the exception of Craters of the Moon Wilderness Area, managed by the National Park Service. None of the Class I areas within 300 miles of Nampa are managed by the United States Fish and Wildlife Service.

Table 1 Class I Areas Included in Modeling Analysis

Eagle Cap Wilderness, OR (eaca2)	Sawtooth Wilderness Area, ID (sawt2)
Strawberry Mountain Wilderness, OR (stmo2)	Selway-Bitterroot Wilderness Area, ID/MT (selw4)
Hells Canyon Wilderness Area, ID/OR (heca2)	Craters of the Moon Wilderness Area, ID (crmowild)
Jarbidge Wilderness Area, ID/NV (jarb2)	

The meteorological inputs to CALPUFF for the analysis were the same data set used previously for the *Subject-to-BART* analysis and the *BART Determination* modeling. The meteorological inputs were prepared by Geomatrix, Inc. (now Environ International) under the direction of representatives from the states of Washington, Idaho, and Oregon, using *Fifth Generation*

[1] *Modeling Protocol for Washington, Oregon and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation.* http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_BART_modeling_protocol.pdf

[2] Tier II Operating Permit No. T2-2009.0105, issued September 7, 2010.

Mesoscale Meteorological Model (MM5) data generated by the University of Washington. The result was a CALMET output file for the three-year period from 2003 through 2005 that covers the entire Pacific Northwest at a 4-km resolution.[3]

Primary particulate matter from these sources is a relatively small contributor to regional haze. Nevertheless, detailed particulate matter speciation was estimated using National Park Service particulate speciation spreadsheets for dry bottom pulverized coal-fired boilers with and without Spray Dry FGD.[4]

The resulting speciated emissions of direct particulate matter emissions can be seen in Table 3. Note, the sulfate (SO_4) in Table 3 is shown as (and input to CALPUFF) as pounds per hour SO_4. However, when totaling the aerosol species under "Total PM_{10}" it is converted to a stoichiometric equivalent mass of ammonium sulfate ($(NH_4)_2SO_4$), since this is the form it assumes in the ambient air, and the mass that is measured in a source test.

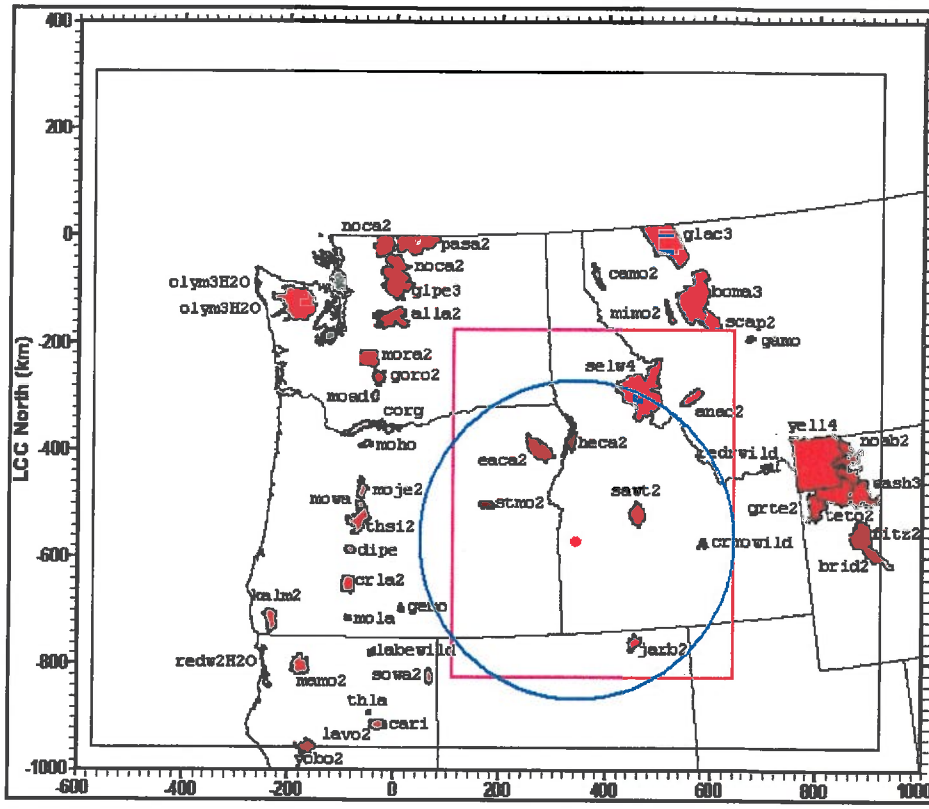

Figure 1 Meteorological (black) CALPUFF (pink) domains with Class I areas within 300-km radius (blue) of TASCO Nampa Factory (red dot).

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[3] CALMET Statistical Report, CALMET Fields for BART Modeling, Idaho, Oregon and Washington, Geomatrix Consultants, Inc., Lynnwood WA 98036, July 2006.

[4] National Park Service, *Particulate Matter Speciation, Coal-Fired Boiler PM_{10}*, http://www nature.nps.gov/air/Permits/ect/ectCoalFiredBoiler.cfm

Table 2 Source Locations and Stack Parameters

Unit	BART Control Equipment	Easting (m)	Northing (m)	Elevation (m)	Stack Height (m)	Stack Diameter (m)	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)
Stack Parameters for "Alternative Benchmark" Scenario (Run ID wzl10492)								
Riley Boiler	Existing Baghouse	534.406	4828.031	753	74.7	3.35	445.9	12.0
B&W 1&2	(n/a)	534.406	4828.031	753	74.7	3.35	445.9	12.0
South Pulp Dryer	(n/a)	534.413	4828.087	753	23.5	3.017	348.5	4.9
Center Pulp Dryer	(n/a)	534.413	4828.099	753	21	3.017	353.4	7.0
North Pulp Dryer	(n/a)	534.415	4828.106	753	27.7	2.13	346.4	6.3
Stack Parameters for "BART" Scenario (with affected sources) (Run ID wzl10495)								
Riley Boiler	FGD + LNB (60.7% Control)	534.406	4828.031	753	74.7	3.35	403.8	11.2
B&W 1&2	LNB (Each 55% Control)	534.406	4828.031	753	74.7	3.35	445.9	12.0
South Pulp Dryer	(n/a)	534.413	4828.087	753	23.5	3.017	348.5	4.9
Center Pulp Dryer	(n/a)	534.413	4828.099	753	21	3.017	353.4	7.0
North Pulp Dryer	(n/a)	534.415	4828.106	753	27.7	2.13	346.4	6.3
Stack Parameters for "BART Alternative" Scenario (Run ID wzl10493)								
Riley Boiler	LNB (60.7% Control)	534.406	4828.031	753	74.7	3.35	440.0	11.7
B&W 1&2	LNB (Each 55% Control)	534.406	4828.031	753	74.7	3.35	440.0	11.7

Table 3 **Emission Rates used in CALPUFF Modeling** [(a)]

Unit	Control Equipment	SO_2 lb/hr	SO_4 lb/hr	NOX lb/hr	HNO_3 lb/hr	NO_3 lb/hr	PMC lb/hr	PMF lb/hr	EC lb/hr	SOA lb/hr	Total PM_{10} lb/hr[(b)]
Emissions from all Sources in Alternative Benchmark Scenario (Run ID wzl10492)											
Riley Boiler	Existing Baghouse	522.3	6.7	373.8	0	0	0.5	0.5	0	2.3	12.5
B&W 1&2 [(c)]	(n/a)	435.0	30.7	227	0	0	2.1	2.1	0	10.5	56.9
South Pulp Dryer	(n/a)	7.5	0.01	80.2	0	0.01	0	31.3	0	5.3	36.6
Center Pulp Dryer	(n/a)	7.5	0.01	80.2	0	0.01	0	31.3	0	5.3	36.6
North Pulp Dryer	(n/a)	2.9	0.01	30.8	0	0.01	0	14.2	0	5.3	19.5
"Alternative Benchmark" Scenario Totals:		*975.1*	*37.43*	*792*	*0*	*0.03*	*2.6*	*79.4*	*0*	*28.7*	*162.2*
Emissions from all sources in "BART" Scenario (with affected sources) (Run ID wzl10495)											
Riley Boiler	Selected BART (FGD + LNB)	104	2.8	147	0	0	0.5	0.5	0	1	5.9
B&W 1&2 [(c)]	Existing Control, B&W Boilers 1&2	435	30.7	227	0	0	2.1	2.1	0	10.5	56.9
South Pulp Dryer	(n/a)	7.5	0.01	80.2	0	0.01	0	31.3	0	5.3	36.6
Center Pulp Dryer	(n/a)	7.5	0.01	80.2	0	0.01	0	31.3	0	5.3	36.6
North Pulp Dryer	(n/a)	2.9	0.01	30.8	0	0.01	0	14.2	0	5.3	19.5
"BART" Scenario Totals:		*556.8*	*33.5*	*565.2*	*0*	*0.03*	*2.6*	*79.4*	*0*	*27.4*	*155.5*
"BART Alternative" Emissions after Implementation (Pulp Dryers shut down) (Run ID wzl10493)											
Riley Boiler	LNB (60.7% Control)	522.3	6.7	147	0	0	0.5	0.5	0	2.3	12.5
B&W 1&2 [(c)]	LNB (Each 55% Control)	435	30.7	103	0	0	2.1	2.1	0	10.5	56.9
"BART Alternative" Scenario Totals:		*957.3*	*37.4*	*250*	*0*	*0*	*2.6*	*2.6*	*0*	*12.8*	*69.4*

(a) Pollutant emissions for sulfur dioxide (SO_2), Nitrogen oxides ($NO_x = NO + NO_2$), nitric acid (HNO_3) and speciated particulate matter species (SO_4), particulate nitrate (NO_3), coarse particulate matter 2.5 – 10µm in aerodynamic diameter (PMC), fine particulate matter < 2.5µm in diameter (PMF), elemental carbon (EC), secondary organic aerosol (SOA), and total particulate matter 10µm and less in aerodynamic diameter (PM_{10}).

(b) Total PM_{10} is not used directly in the model but represents total of PM species for information only. SO_4 is added into total PM_{10} as ammonium sulfate (SO_4 lb/hr x (132/96)).

(c) B&W Boilers 1&2 refer to two (non-BART) Babcock &Wilcox Boilers, Units 1 and 2 that operate at the Nampa Factory in addition to the Riley Boiler

BART Alternative Modeling Results

"BART" and "BART Alternative" Model Detailed Results

Detailed model results showing regional haze impacts at all seven Class I areas within 300 km of the source are summarized for the "BART" scenario in Table 4, and for the "BART Alternative" scenario in Table 5. It is important to emphasize that both the "BART" and the "BART Alternative" results shown in Table 4 and Table 5 include all emission sources involved in the BART determinations and in the BART Alternative, so that comparison can be made on an equivalent basis, with the full precursor mix accounted for from all affected sources. Overall (three-year) results for all scenarios are summarized in Table 6 to facilitate comparisons.

In its 2005 BART guidelines, EPA determined that a source whose 98th percentile daily average haze impact (haze index) is greater than 0.5 deciview above natural background is considered to <u>contribute</u> to regional haze. Impacts above 1.0 deciview are considered to <u>cause</u> regional haze impacts. By selecting the 98th percentile, the top 7 days in any year, or top 21 days in three years, EPA intended to minimize the effects of extreme meteorology and conservative assumptions. Table 4 and Table 5 highlight the two averaging periods generally used in BART modeling analyses:

- 8th highest Δdv value for each of the years modeled (2003-2005), representing the 98th percentile (8/365 = 0.02) cutoff for Δdv in the each year. In addition the numbers of days in each year above the 0.5 Δdv threshold are shown.
- 22nd highest value for the entire period from 2003 through 2005, representing the 98th percentile (22/1095 = 0.02) cutoff for Δdv over three years. In addition the numbers of days in all three years above the 0.5 Δdv threshold are shown.

The pre-BART, 3-year modeled impacts shown in Table 4 and Table 5 indicate that the "Alternative Benchmark" scenario does not "contribute" (>0.5Δdv) to regional haze at Craters of the Moon, Jarbidge, Sawtooth and Selway-Bitterroot wilderness areas, the Class I areas east of Nampa. On the other hand, this benchmark scenario does "cause" regional haze impacts (>1.0Δdv) at the 3 Class I areas east of the facility, i.e. Eagle Cap, Strawberry Mountain and Hells Canyon wilderness areas. In addition, Table 4 and Table 5 show that the meteorology in 2004 resulted in the highest modeled impacts and most days above the 0.5Δdv threshold at all sites. Figure 2 clearly shows that the model-predicted visibility impacts at Eagle Cap (due to the existing Riley boiler) were highest in the winter season, and that January 2004 had the highest predicted impacts during the three-year model period. In addition, from day 60 through day 280, only 3 days in 3 years appear to exceed the 0.5Δdv threshold for a 98th percentile day "contributing" to a haze at a Class I area. Since this frequency (3 days in 660) represents only 0.45% of the non-winter days, it suggests that the Riley boiler does not "contribute" to the haze impacts, at the level defined by EPA, outside of the October – February period. However it does "cause" haze impacts (>1 Δdv) at the western-most 3 Class I areas during the winter time when non-carbon impacts are the greatest.

Comparison to Measured Extinction at IMPROVE monitoring sites

To gain confidence in model results, it is useful to examine how model results behave in comparison to monitored aerosol extinction at IMPROVE monitoring sites. For this purpose, it is useful to understand how light extinction is determined from aerosol species concentrations and how extinction relates to the "haze index" or changes in visibility relative to the background visibility in terms of delta deciviews (Δdv). Light extinction (b_{ext}) is computed from aerosol species concentrations and reported in units of reciprocal megameters (Mm^{-1}) according to the equation:

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray} \qquad \text{(Eqn 1)}$$

Equation 1 applies to either measured or modeled aerosol concentrations, where:

f(RH) are monthly averaged relative humidity coefficients, specifically tabulated for each Class I area each month,
b_{Ray} is Raleigh scattering due to air molecules, Mm^{-1}
$[(NH_4)_2SO_4]$ is the ammonium sulfate concentration formed from SO_s, $\mu g/m^3$
$[NH_4NO_3]$ is the ammonium nitrate concentration formed from NO_x, $\mu g/m^3$
[OC] is the organic carbon concentration, $\mu g/m^3$ (equivalent to "SOA" in Table 3)
[Soil] is the fine geologic particulate matter, $\mu g/m^3$ (equivalent to "PMF" in Table 3),
[Coarse Mass] is the coarse particulate matter, $\mu g/m^3$ (equivalent to "PMC" in Table 3), and
[EC] is the elemental carbon, $\mu g/m^3$

Light extinction is not measured directly at IMPROVE sites, but is calculated based on aerosol measurements of the species in Equation 1. In this document, the terms "measured extinction" or "monitored extinction" refer to light extinction calculated by Equation 1 based on direct aerosol filter measurements and reported by the IMPROVE monitoring program. When source emissions are modeled to estimate light extinction impacts resulting from those emissions, the resulting $b_{ext\ (source)}$ is compared to background extinction, $b_{ext\ (bkg)}$, to predict the haze index in terms of delta-deciviews:

$$\Delta dv = 10\ ln\ [\ (\ b_{ext\ (bkg)} + b_{ext\ (source)}\ )\ /\ (\ b_{ext\ (bkg)}\ )\ ] \qquad \text{(Eqn 2)}$$

A time series view of 2004 light extinction based on measured aerosol concentrations and modeled pre-BART Riley Boiler concentrations at Hells Canyon (Figure 3) again suggests that the winter months experience the highest visibility impacts and that the January 2004 stagnation episode produced the greatest monitored and modeled aerosol extinction over the 3 year period. The similarity in monitor-based and modeled annual patterns shown in Figure 3 suggests that the model captures the seasonal variation in haze conditions well and that both the observed and modeled visibility impacts are highest in the winter time and much lower from March to mid-October.

Summary of "BART" results.
The visibility improvement for the "BART" scenario, in comparison to the Alternative Benchmark scenario (Table 4) shows a reduction in the three-year 22nd highest Δdv of 0.689 Δdv at Eagle Cap, the most impacted area, and 0.119 Δdv at Jarbidge Wilderness, the least impacted area. Similarly, the number of days in three years above the 0.5 Δdv threshold at Eagle Cap decreases from 195 days to 149 days, a 46 day reduction, while Jarbidge is projected to see only a three day reduction. The sum of days in 3 years above 0.5 Δdv at all seven Class I areas decreases from 455 days for the Alternative Benchmark scenario to 316 days for the "BART" scenario, a reduction of 139 days overall.

Summary of "BART Alternative" Results

The visibility improvement for the "BART Alternative" scenario in comparison to the "Alternative Benchmark" scenario (Table 5) shows a reduction in the three-year 22nd highest Δdv at Eagle Cap from 2.201 to 1.411Δdv, a visibility improvement of 0.790 Δdv. The number of days in the three-year period above the 0.5 Δdv threshold at Eagle Cap decreases from 195 days to 126 days, a 69 day reduction, while Jarbidge is projected to see a three day reduction, identical to the "BART" scenario. The sum of days above 0.5 Δdv at all the Class I areas combined drops from 455 for the "Alternative Benchmark" scenario to 275 days for the "BART Alternative" scenario, a reduction of 180 days. A very small visibility degradation appears at Selway-Bitterroot Wilderness Area.

Table 4 Summary of Visibility Impacts for TASCO-Nampa "BART" Scenario

Class I Area	Operating Scenario	Change in Visibility Compared Against 20% Best Days (Natural Background)							
		Δdv larger than 0.5 from one year period						Δdv > 0.5 over 3 yr	
		2003		2004		2005		2003-2005	
		8th high Δdv[a]	Days > 0.5Δdv[b]	8th high Δdv[a]	Days > 0.5Δdv[b]	8th high Δdv[a]	Days > 0.5Δdv[b]	22nd Highest[c]	Total Days[d] >0.5Δdv
Eagle Cap Wilderness, OR	"Alternative Benchmark" (wzI10492)	1.611	48	2.212	72	2.178	75	2.201	195
	"BART"[e] (wzI10495)	1.103	30	1.551	55	1.509	64	1.512	149
	Visibility Improvement[f]	*0.508*	*18*	*0.661*	*17*	*0.669*	*11*	*0.689*	*46*
Craters of the Moon NM Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.336	1	0.407	6	0.318	3	0.393	10
	"BART"[e] (wzI10495)	0.239	0	0.273	3	0.233	1	0.267	4
	Visibility Improvement[f]	*0.097*	*1*	*0.134*	*3*	*0.085*	*2*	*0.126*	*6*
Hells Canyon Wilderness ID/OR	"Alternative Benchmark" (wzI10492)	1.269	27	1.693	51	1.515	51	1.582	129
	"BART"[e] (wzI10495)	0.884	20	1.163	32	1.049	35	1.092	87
	Visibility Improvement[f]	*0.385*	*7*	*0.530*	*19*	*0.466*	*16*	*0.490*	*42*
Jarbidge Wilderness, NV	"Alternative Benchmark" (wzI10492)	0.275	1	0.379	3	0.420	4	0.375	8
	"BART"[e] (wzI10495)	0.192	1	0.256	2	0.278	2	0.256	5
	Visibility Improvement[f]	*0.083*	*0*	*0.123*	*1*	*0.142*	*2*	*0.119*	*3*
Sawtooth Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.470	7	0.519	8	0.435	3	0.470	18
	"BART"[e] (wzI10495)	0.340	2	0.349	4	0.293	0	0.319	6
	Visibility Improvement[f]	*0.130*	*5*	*0.170*	*4*	*0.142*	*3*	*0.151*	*12*
Selway-Bitterroot Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.317	0	0.587	8	0.492	7	0.439	15
	"BART"[e] (wzI10495)	0.212	0	0.387	1	0.327	2	0.281	3
	Visibility Improvement[f]	*0.105*	*0*	*0.200*	*7*	*0.165*	*5*	*0.158*	*12*
Strawberry Mountain Wilderness, OR	"Alternative Benchmark" (wzI10492)	1.419	18	0.882	22	2.308	40	1.462	80
	"BART"[e] (wzI10495)	0.987	13	0.644	15	1.677	34	1.076	62
	Visibility Improvement[f]	*0.432*	*5*	*0.238*	*7*	*0.631*	*6*	*0.386*	*18*
All Areas	***Reduction in Total Days > Δdv, all Class I Areas Combined***	***2003:***	***36***	***2004:***	***58***	***2005:***	***45***	***3-Yr:***	***139***

(a) The 8th highest delta-deciview impact for the calendar year.
(b) Total number of days in 1 year that exceeded 0.5 delta deciviews.
(c) The 22nd highest delta-deciview impact for the three-year period.
(d) Total number of days in the three-year period that exceed 0.5 delta deciviews.
(e) "BART" (with quotations) refers to the Riley Boiler with Spray Dry FGD and LNB controls plus the pre-BART emissions of the B&W boilers 1&2 and three pulp dryers so that the results may be compared to the "BART Alternative" and the "Alternative Benchmark" scenarios on an equivalent basis.
(f) Visibility improvement is calculated as the difference between the "Alternative Benchmark" scenario and the "BART" scenario modeled values.

Table 5 Summary of Visibility Impacts for TASCO-Nampa "BART Alternative" Scenario

Class I Area	Operating Scenario	Change in Visibility Compared Against 20% Best Days (Natural Background)							
		Δdv larger than 0.5 from one year period						Δdv > 0.5 over 3 yr	
		2003		2004		2005		2003-2005	
		8th high Δdv[(a)]	Days > 0.5Δdv[(b)]	8th high Δdv[(a)]	Days > 0.5Δdv[(b)]	8th high Δdv[(a)]	Days > 0.5Δdv[(b)]	22nd Highest[(c)]	Total Days[(d)] >0.5Δdv
Eagle Cap Wilderness, OR	"Alternative Benchmark" (wzI10492)	1.611	48	2.212	72	2.178	75	2.201	195
	"BART Alternative" (wzI10493)	0.921	22	1.434	49	1.469	55	1.411	126
	Visibility Improvement [(e)]	0.690	26	0.778	23	0.709	20	0.790	69
Craters of the Moon NM Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.336	1	0.407	6	0.318	3	0.393	10
	"BART Alternative" (wzI10493)	0.230	0	0.260	2	0.200	1	0.245	3
	Visibility Improvement [(e)]	0.106	1	0.147	4	0.118	2	0.148	7
Hells Canyon Wilderness ID/OR	"Alternative Benchmark" (wzI10492)	1.269	27	1.693	51	1.515	51	1.582	129
	"BART Alternative" (wzI10493)	0.758	17	1.173	31	1.044	32	1.059	80
	Visibility Improvement [(e)]	0.511	10	0.520	20	0.471	19	0.523	49
Jarbidge Wilderness, NV	"Alternative Benchmark" (wzI10492)	0.275	1	0.379	3	0.420	4	0.375	8
	"BART Alternative" (wzI10493)	0.193	1	0.252	2	0.251	2	0.234	5
	Visibility Improvement [(e)]	0.082	0	0.127	1	0.169	2	0.141	3
Sawtooth Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.470	7	0.519	8	0.435	3	0.470	18
	"BART Alternative" (wzI10493)	0.268	1	0.340	4	0.278	1	0.307	6
	Visibility Improvement [(e)]	0.202	6	0.179	4	0.157	2	0.163	12
Selway-Bitterroot Wilderness, ID	"Alternative Benchmark" (wzI10492)	0.317	0	0.587	8	0.492	7	0.439	15
	"BART Alternative" (wzI10493)	0.206	0	0.383	2	0.329	2	0.298	4
	Visibility Improvement [(e)]	0.111	0	0.204	6	0.163	5	0.141	11
Strawberry Mountain Wilderness, OR	"Alternative Benchmark" (wzI10492)	1.419	18	0.882	22	2.308	40	1.462	80
	"BART Alternative" (wzI10493)	0.737	10	0.540	11	1.487	30	0.917	51
	Visibility Improvement [(e)]	0.682	8	0.342	11	0.821	10	0.545	29
All Areas	***Reduction in Total Days > 0.5 dv, all Class I Areas Combined***	***2003:***	***51***	***2004:***	***69***	***2005:***	***60***	***3-Yr:***	***180***

(a) The 8th highest delta-deciview impact for the calendar year.
(b) Total number of days in 1 year that exceeded 0.5 delta deciviews.
(c) The 22nd highest delta-deciview impact for the three-year period.
(d) Total number of days in the three-year period that exceed 0.5 delta deciviews.
(e) Visibility improvement is calculated as the difference between the "Alternative Benchmark" scenario and the "BART Alternative" scenario modeled values.

Table 6 Summary of scenarios and net visibility improvement from "BART Alternative" in comparison to "BART" scenario

Class I Area	"Alternative Benchmark"(a) (wzI10492)		"BART"(b) (wzI10495)		"BART Alternative"(c) (wzI10493)		Net Visibility Improvement ("BART" – "BART Alternative")	
	22nd Highest (d)	Total Days >0.5Δdv (e)	22nd Highest (d)	Total Days (e) >0.5Δdv	22nd Highest (d)	Total Days >0.5Δdv (e)	Δdv Reduction, 22nd Highest Day	Decrease in No. of Days >0.5 Δdv
Eagle Cap Wilderness, OR	2.201	195	1.512	149	1.411	126	0.101	23
Craters of the Moon Wilderness, ID	0.393	10	0.267	4	0.245	3	0.022	1
Hells Canyon Wilderness, ID/OR	1.582	129	1.092	87	1.059	80	0.033	7
Jarbidge Wilderness, NV	0.375	8	0.256	5	0.234	5	0.022	0
Sawtooth Wilderness, ID	0.47	18	0.319	6	0.307	6	0.012	0
Selway-Bitterroot Wilderness, ID	0.439	15	0.281	3	0.298	4	-0.017	-1
Strawberry Mountain Wilderness, OR	1.462	80	1.076	62	0.917	51	0.159	11
Total Number of Days with Improved Visibility:		455		316		275		41

(a) Includes pre-BART emissions of all sources involved in BART and the BART Alternative: Riley Boiler, B&W Boilers 1&2 and pulp dryers.

(b) Includes all sources involved in BART and the BART Alternative under "BART" operations: Riley Boiler (LNB + SD-FGD), B&W Boilers 1&2, three pulp dryers operating.

(c) Includes all sources involved in BART and the BART Alternative under BART Alternative operations: Riley Boiler (LNB), B&W Boilers 1&2 (LNB), three pulp dryers shut down.

(d) The 22nd highest Δdv value for the three-year period (2003 – 2005).

(e) Total number of days in the three-year period that exceed 0.5 Δdv.

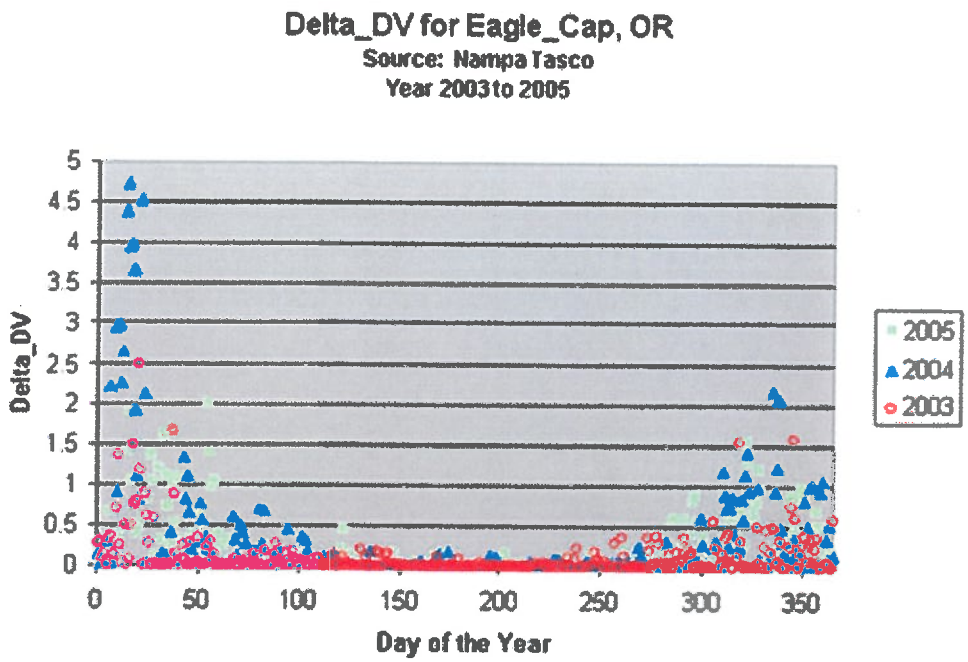


Figure 2 Modeled seasonal variation in delta-deciview impacts due to TASCO's Riley Boiler (existing control), over the three model years

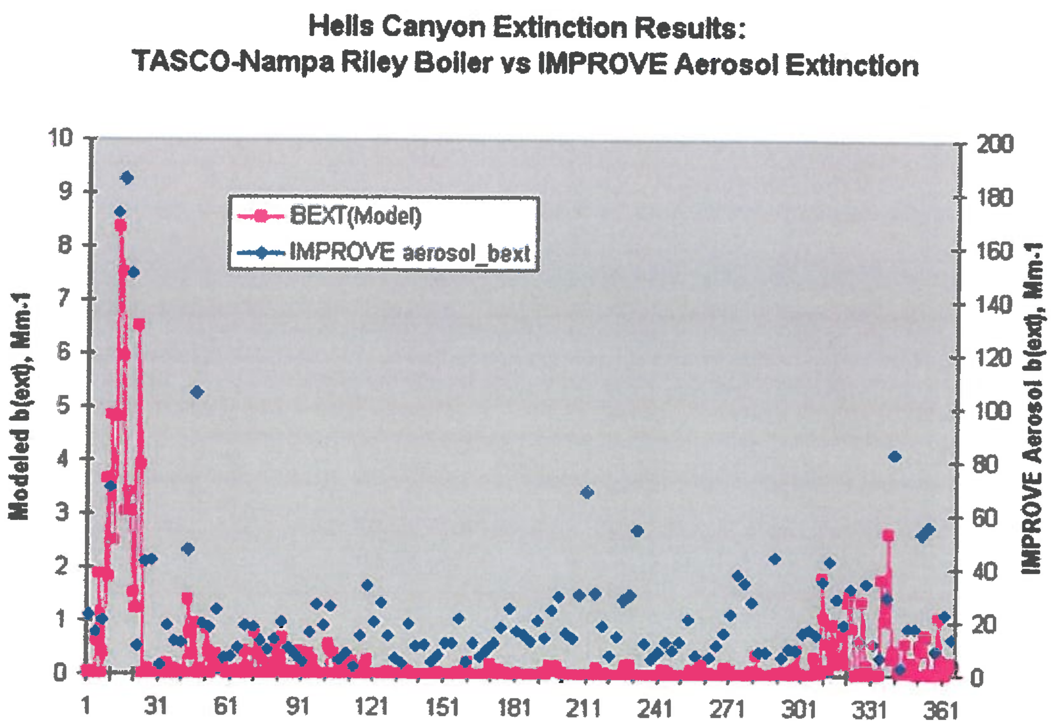


Figure 3 Comparison of modeled extinction due to the Riley Boiler (existing control) (left axis) and measured total aerosol extinction at the Hells Canyon IMPROVE site (right axis).

Other Considerations

In preliminary discussion of the proposed changes with FLMs, questions were raised about finding sufficient alternative controls at the facility to include in a BART alternative and about the effect on visibility impacts that would result from reducing the level of SO_2 control and replacing it with increased NO_x control. As a result, DEQ reassessed the selection of emission sources included in BART Alternative modeling and evaluated whether inordinate visibility impacts were projected to shift impacts to other Class I areas or to other seasons. This section describes those evaluations.

Availability of other Emission Sources for Inclusion in the BART Alternative

Alternatives to the control of SO_2 emissions by Spray Dry-FGD were proposed by TASCO, in light of both the high cost and the environmental impairment due to the waste stream produced by Spray Dry FGD. During the evaluation, the FLMs suggested that in seeking alternative emission reductions, DEQ should examine the entire facility-wide emission inventory to determine if other emission sources, in addition to the two B&W Boilers and the Pulp Dryers could be considered for inclusion as part of a BART Alternative. DEQ examined the primary regional haze precursors in the facility-wide emission inventory for the TASCO Nampa Factory in the most recent statewide point source emissions inventory (2010). The pulp dryers had been shut down by 2010 and did not appear in this inventory, but were included as reductions in the BART Alternative. The facility-wide emissions of NO_x, SO_2 and PM_{10} are shown in Figure 4, Figure 5, and Figure 6 (respectively). These charts indicate that the Riley Boiler and the B&W boiler Units 1 & 2 together comprise 97% of the total facility-wide NO_x emissions, 99% of the SO_2 emissions and 98% of PM_{10} emissions. This review confirmed that the emission sources contributing the greatest share of visibility-impairing emissions from the Nampa Factory are included in the proposed BART Alternative and that no other significant visibility-impairing pollutant emission sources are available at the facility for inclusion in the BART Alternative control plan.

Effects on Visibility from Replacing SO_2 Control with Additional NO_x Control

The proposed BART Alternative replaces the Spray-Dry Flue Gas Desulfurization SO_2 control on the Riley Boiler with additional NO_x controls on the two Babcock & Wilcox boilers and with additional NO_x, SO_2 and PM_{10} reductions achieved by shutting down the 3 pulp dryers. Visibility reductions resulting from this proposed change would potentially be limited if the highest regional haze impacts were primarily caused by sulfate, or if sulfate was a predominant contributor in any particular season during which the facility contributes to significant visibility degradation. To assess the importance of nitrate, sulfate and primary particulate matter to the regional haze levels, DEQ investigated the monitored impacts at all the Class I areas and seasons most impacted by the TASCO Nampa Factory. IMPROVE aerosol monitoring data[5] for the modeling period are presented in this section to provide a multi-year evaluation of pre-BART visibility conditions and their seasonal variation.

[5] Western Regional Air Partnership (WRAP), WRAP-TSS Web site, September 2011. http://vista.cira.colostate.edu/TSS/Results/Monitoring.aspx

Most Impacted Areas

The modeled visibility impacts from sources at the TASCO Nampa plant were highest at the Class I areas at the west end of the Snake River Valley: Eagle Cap, Strawberry Mountain and Hells Canyon wilderness areas. These areas also experience the highest monitored aerosol impacts, with the exception of isolated wildfire impacts that affect sites throughout the west. Monitoring data for the years of the modeling study, 2003, 2004 and 2005 are shown in Figure 7, Figure 8, and Figure 9 (respectively), for the Starkey IMPROVE site. The Starkey site is located between Eagle Cap and Strawberry Mountain and is intended to represent both of these Wilderness areas. Figure 10, Figure 11, and Figure 12 show the measured aerosol extinction for the same three years at Hells Canyon IMPROVE site. The three Class I areas represented by these two IMPROVE sites reflect very similar patterns of observed seasonal visibility degradation and aerosol composition. A review of Figure 7 through Figure 12 indicates that:

- The greatest non-carbon impacts are in the winter, when nitrate predominates extinction (80 to 150 Mm^{-1}) and sulfate is relatively low. This aerosol formation regime generally occurs from November through February.
- The greatest carbon impacts occur in the summer, sometimes extending into fall, when carbon predominates extinction (~120 – 280 Mm^{-1}), likely from wildfires in the region, nitrate is negligible, and sulfate is relatively low (< $10Mm^{-1}$). It is important to note that ammonium nitrate is volatile at summertime temperatures and does not exist as an aerosol that can impact visibility during these warmer seasons.
- The season with the best visibility (lowest extinction) is spring, when sulfate predominates. During this period, most sulfate impacts appear to be between about 5 and 10 Mm^{-1}, with the highest sulfate impact in 3 years reaching just over 20 Mm^{-1}. Nevertheless, the observed aerosol impacts in the spring are relatively low compared to winter and summer when extinction reaches 120 to 300 Mm^{-1} most years.

The Starkey IMPROVE site represents the two Class I areas with greatest modeled impacts from the TASCO Nampa boilers so seasonal regional haze impacts measured at Starkey were examined in more detail. Daily extinction values for measured aerosol species were obtained from the WRAP-TSS[5] and summarized into monthly average extinction values. Figure 13 shows monthly averaged total extinction at Starkey, and average extinction by species for all days in the three-year modeling period, 2003 – 2005. Error bars representing the 95% Confidence Intervals (CI) are also shown to indicate variability. The total extinction line demonstrates that average extinction is the highest in the summer and fall months, as a result of high organic carbon. The colder months of November through February experience the second highest total extinction and the predominant species is ammonium nitrate. The season with the best visibility (lowest average extinction) is spring (March through June) when average aerosol extinction is half to a third of that in the higher seasons. Sulfate predominates for most of the spring months averaging around 5 – 7 Mm^{-1} with very little variability. Carbon increases to levels comparable to sulfate in May and June.

Figure 14 shows the monthly average extinction pattern for the 20% of days observed each month with the worst visibility conditions. For the worst 20% of days, the greatest contributors to regional haze impacts are carbon in the summer and fall and nitrate in the winter. Again, sulfate predominates in the spring when visibility conditions are best, yet still contributes only about 8 – 12 Mm^{-1} when averaged over the 20% of days with the highest extinction.

Less Impacted Areas

The TASCO Nampa Factory modeled impacts for the "Alternative Benchmark" scenario revealed that the other Class I areas further away and to the east of Nampa experienced modeled visibility impacts ranging from only 17 to 21% of the impacts at Eagle Cap, for the 22nd highest Δdv days. None of the 22nd highest days exceed 0.5Δdv, the EPA suggested threshold for "contributing" to a haze problem. The measured haze impacts at Craters, Jarbidge, Sawtooth and Selway-Bitterroot were also much lower than those at Starkey and Hells Canyon. The measured aerosol extinction charts for 2003, 2004 and 2005 are shown for Sawtooth Wilderness in Figure 15, Figure 16, and Figure 17 (respectively); for Jarbidge Wilderness in Figure 18, Figure 19, and Figure 20; for Craters of the Moon Wilderness in Figure 21, Figure 22, and Figure 23; and for the Selway-Bitterroot Wilderness Area in Figure 24, Figure 25, and Figure 26. It should be noted, that the scale for each extinction figure changes, and while the highest (nitrate-impacted) days at Starkey and Hells Canyon reach 100 to 180 Mm^{-1}, the highest nitrate-impacted days at the more distant sites east of Nampa have total extinction levels reaching only 40 to 55 Mm^{-1}.

The observed aerosol extinction charts for the eastern group of Class I areas indicate that:

- At Jarbidge, Sawtooth and Selway-Bitterroot wilderness areas, measured nitrate aerosol extinction was very low, even in winter, suggesting very little impact from the TASCO Nampa Factory. Carbon dominated at these sites during the summer wildfire season, peaking around 130 Mm^{-1} at Sawtooth and over 350 Mm^{-1} at Selway-Bitterroot. Sulfate was more significant in the spring with most days below 5 - 6 Mm^{-1} and only a few days in the range 10 – 20 Mm^{-1}.
- At Craters of the Moon Wilderness Area (Figure 21 through Figure 23) the highest observed aerosol extinction resulted from nitrate in winter, up to 55 Mm^{-1}, and carbon in the summer up to 100 Mm^{-1}. Sulfate at Craters of the Moon was similar in magnitude to sulfate at all the other sites, typically around 5 - 10 Mm^{-1} or less, and never exceeds 20 Mm^{-1}, similar to the other Class I areas. This appears to be indicative of a very consistent regional background, with very little variation amongst all 7 Class I area.

Overview of Seasonal Visibility Analysis

The above analysis of seasonal visibility impacts suggests that the greatest impacts occur at Starkey and Hells Canyon as a result of wintertime nitrate impacts and summer/fall organic carbon impacts, probably from wildfires. A review of sulfate impacts at all the Class I areas (above) suggests that the level of springtime sulfate impacts (Figure 13 and Figure 14) at the Starkey IMPROVE site (~ 6 Mm^{-1} on the average day and 8 - 12 Mm^{-1} on the highest 20% of days) approximates a regional background level, similar to the levels apparent at the Class I areas east of Nampa (Jarbidge, Sawtooth, Craters of the Moon and Selway-Bitterroot) where TASCO Nampa emissions were found to not "contribute" significantly to the modeled extinction.

To confirm the seasonality of the modeled impacts at Eagle Cap, the 22 highest days from the "Alternative Benchmark", "BART" and "BART Alternative" scenarios were plotted in

Figure 27. All of the highest 22 days were observed in the winter time, and the "BART Alternative" results showed a slight improvement over the "BART" results.

It may be concluded that the "BART Alternative" scenario results in greater reductions in haze on the 98th percentile days, and more days below the 0.5Δdv threshold than the "BART" scenario because it more effectively addresses the primary aerosol contributor (nitrates) during the most impacted season at the most impacted Class I areas. This overall improvement comes at the price of slightly less improvement during the best visibility period in the spring, when sulfate is a much smaller, but still predominant contributor to visibility degradation. Thus, the reduction in SO_2 control in lieu of more NO_x control results in slightly less visibility improvement on the clearest days in the spring (< 5Mm^{-1}). Nevertheless, greater overall improvement in visibility conditions occurs with the "BART Alternative" in comparison to the "BART" scenario.

Additional Environmental Benefits in Reducing Ozone

The Treasure Valley, including the Boise River and Snake River Valleys and stretching from Mountain Home, Idaho to Malheur County, Oregon, has been struggling with elevated summertime ozone conditions for a number of years. As shown in Figure 28, the Treasure Valley area remains perilously close to exceeding the ozone National Ambient Air Quality Standard (NAAQS). In 2008, the area escaped non-attainment by less than a part per billion. In 2010 the area was again very close to the proposed (but now deferred) range of the revised ozone NAAQS (60 – 70 ppb). DEQ believes that a recession-induced reduction in traffic, perhaps along with beneficial weather patterns has helped to avoid a non-attainment designation in recent years but that as traffic increases and weather varies, the attainment status of this area is precarious. As a result, Idaho has taken unprecedented steps to lower VOC and NO_x ozone precursor emissions, including Stage II vapor control requirements and the nation's only vehicle testing program (to our knowledge) that was not mandated by EPA in an ozone non-attainment plan. This testing program, started in June 2010 in Canyon County, where the TASCO Nampa Factory is located and was recently evaluated to determine the emission reductions it is providing. Based on MOVES modeling results, DEQ determined that the program provides approximately a 6.3% reduction in VOCs and a 2.7% reduction in NO_x. The NO_x reductions correspond to a 162 ton per year reduction or an annualized reduction of 0.4 tons per day.

In its ongoing effort to be proactive in addressing the ozone problem, DEQ assessed the ozone mitigation benefits of a number of potential control measures in the CMAQ photochemical model, ranging from VMT reductions to reductions in emissions from lawn and garden equipment and solvent degreasing controls, etc. DEQ found that while VOC plus NO_x reductions are most effective, NO_x reductions of around 2 tons per day from the TASCO Factory is expected to result in a reduction of the peak 8-hour ozone concentration of approximately 0.1 part per billion (ppb) on high ozone days. This is a better reduction than many of the other options, including further seasonal lowering of the Reid Vapor Pressure in gasoline, a 54% VOC reduction from a solvent-degreasing regulatory program, a 10% reduction in lawn and garden emissions, and a 10% reduction in vehicle refueling emissions.

Ozone mitigation is only beneficial in the summertime. Thus, when TASCO's winter processing campaign is over in the spring, less boiler capacity is required and at times the B&W Boilers 1&

2 are not used, in which case summer ozone benefits from lowering the NO_x emissions from the B&W boilers would not contribute to ozone mitigation. However, TASCO has confirmed that in addition to the Riley Boiler, the B&W boilers usually operate about 30 days during the summer ozone season (range is 20 to 60 days). As a result, on a significant number of summer days, DEQ anticipates that the BART Alternative will provide ozone reduction benefits in the Treasure Valley.

The "BART Alternative" scenario, achieves 6.5 tons per day of NO_x reductions in comparison to the "Alternative Benchmark", more than double the 2.7 tons per day reduction from the "BART" scenario. This quantity represents the greatest NO_x reduction of any ozone control measures DEQ has evaluated to date. While NO_x-only controls are not as effective as combined NO_x plus VOC controls, this large reduction, in conjunction with VOC-only controls should be sufficient to significantly reduce the number of unhealthy days and may help to avoid a non-attainment designation in the next few years.

Conclusions

This air quality modeling analysis addresses the visibility impacts of the "BART" and "BART Alternative" control scenarios for the BART-subject Riley Boiler at TASCO's Nampa Factory. The "BART" scenario results in an overall 36% reduction in acid gas emissions, while the "BART Alternative" scenario results in a 31% reduction, however total acid gas plus particulate matter emissions for the two scenarios are virtually identical. TASCO's alternative proposal involves replacing Spray Dry Flue Gas Desulfurization SO_2 controls on the Riley Boiler with low-NO_x burner controls on two non-BART boilers, along with shutting down three pulp dryers. While the total emissions of all species are similar, the "BART Alternative" achieves greater improvements in visibility because the most severe non-carbon visibility impairment at the Class I areas nearest the Nampa Factory is dominated by ammonium nitrate in the winter and replacing some of the SO_2 control with increased NO_x control provides greater reductions on more poor visibility days. An analysis of seasonal aerosol extinction observations indicates that while the greatest improvements will occur in the winter when impacts are greatest, there will be a small visibility impairment in the spring when the visibility conditions are best and a low-level sulfate background dominates the extinction.

Nevertheless, overall modeled improvements show that the modeled visibility degradation on the 22nd highest impacted day at Eagle Cap was reduced by an additional 0.101 Δdv for the "BART Alternative" scenario in comparison to the "BART" scenario, and there were projected to be 23 less days at Eagle Cap over the 0.5 Δdv threshold. Taking a broader geographic view, the combined number of days at all seven areas above the 0.5 Δdv threshold were reduced by an additional 41 days for the "BART Alternative" scenario in comparison to the "BART" scenario.

Finally, the "BART Alternative" scenario provides significantly greater NO_x reductions than the "BART" scenario (2.4 times greater), and therefore is preferred by DEQ over the "BART" scenario for additional environmental benefits it is expected to bring to the ozone mitigation efforts in the Treasure Valley, in addition to the improved visibility expected for Class I Areas in the region.

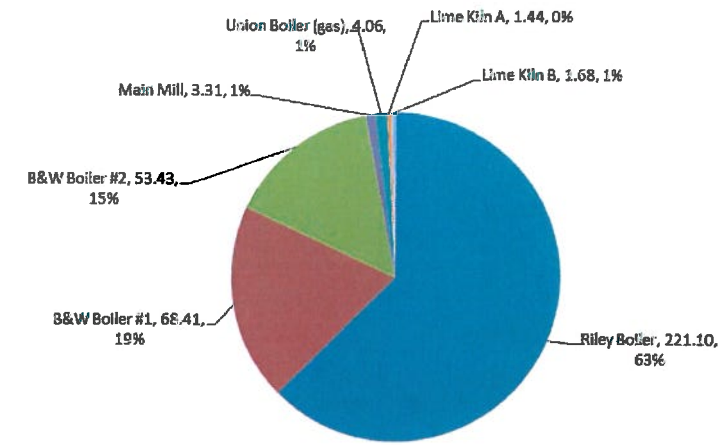


Figure 4 TASCO Nampa Facility-Wide NO_x Emissions

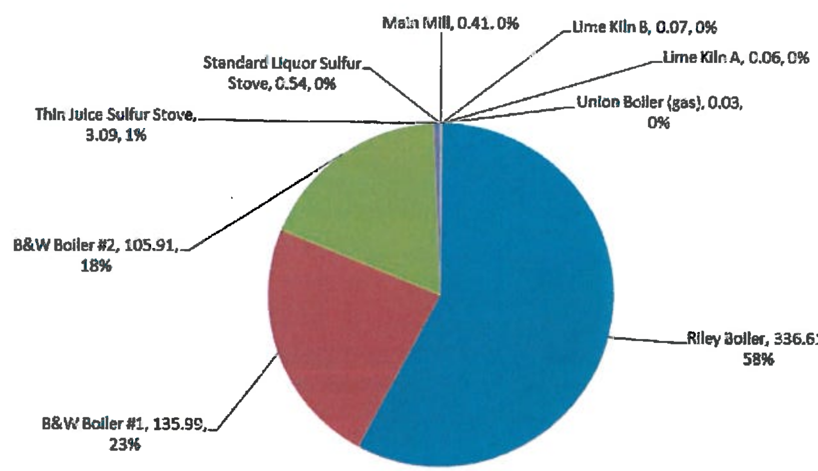


Figure 5 TASCO Nampa Facility-Wide SO2 Emissions

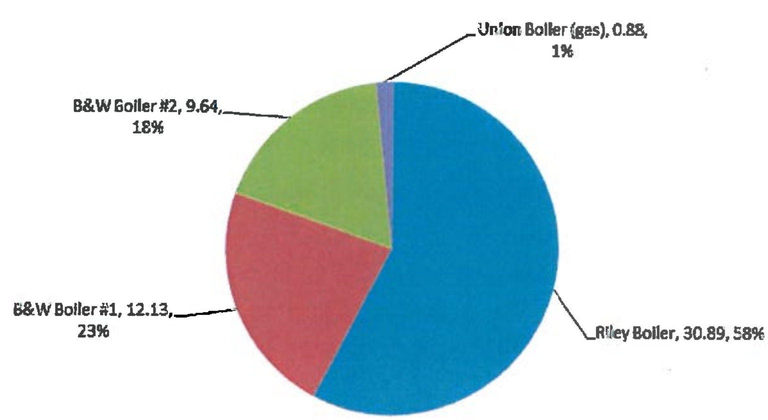


Figure 6 TASCO Nampa Facility-Wide PM_{10} Emissions

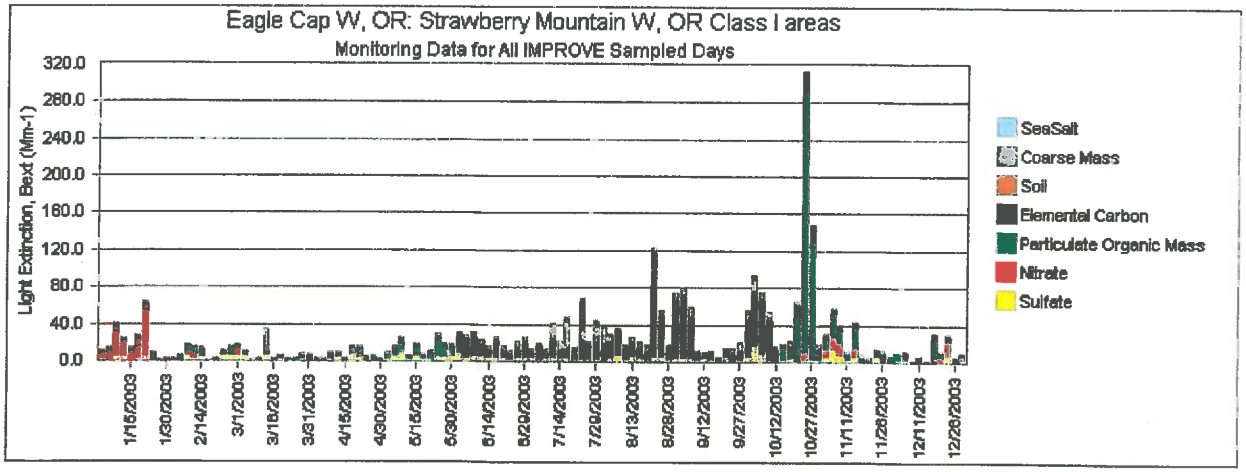


Figure 7 Light extinction (Mm-1) based on measured aerosol concentrations at Starkey IMPROVE site, representing Eagle Cap and Strawberry Mountain, 2003.

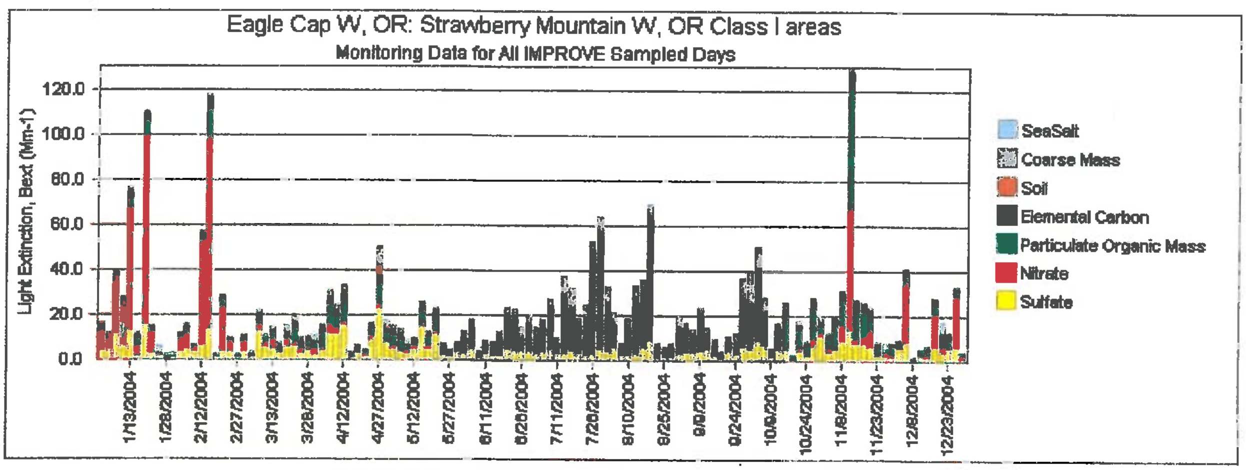


Figure 8 Light extinction (Mm-1) based on measured aerosol concentrations at Starkey IMPROVE site, 2004.

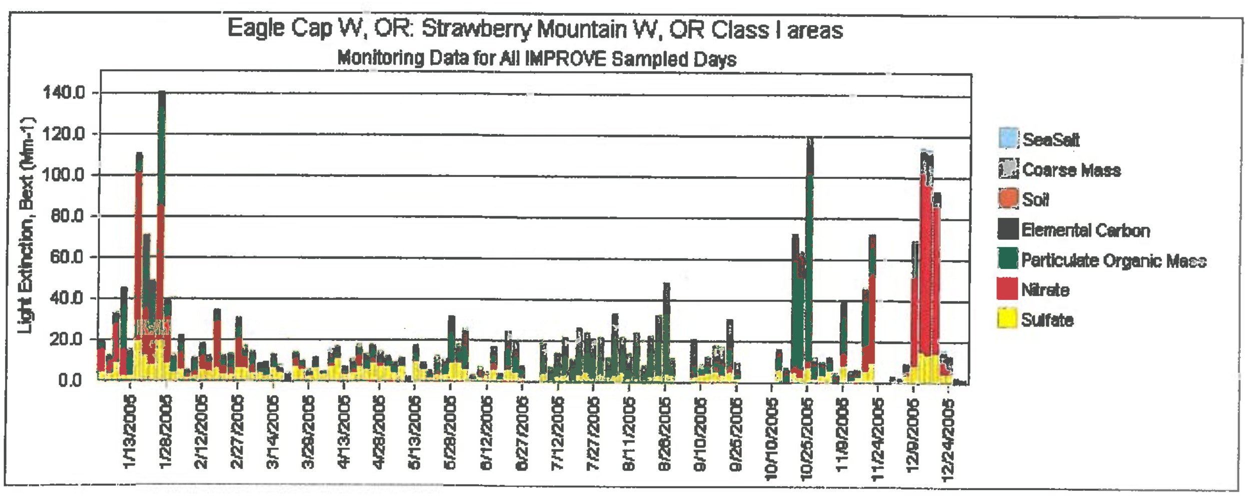


Figure 9 Light extinction (Mm-1) based on measured aerosol concentrations at Starkey IMPROVE site, 2005.

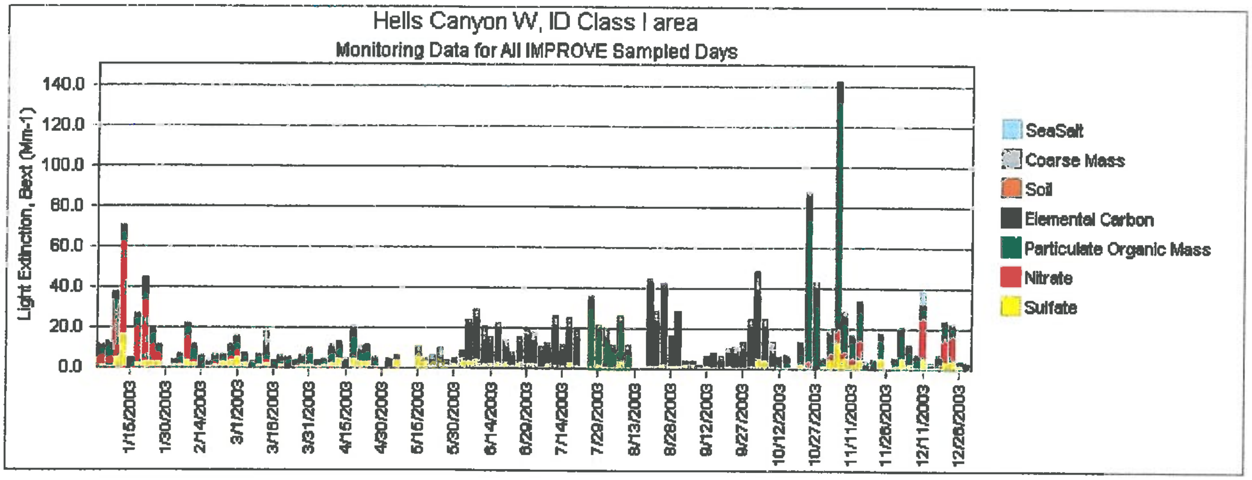


Figure 10 Light extinction (Mm-1) based on measured aerosol concentrations at Hells Canyon IMPROVE site, 2003.

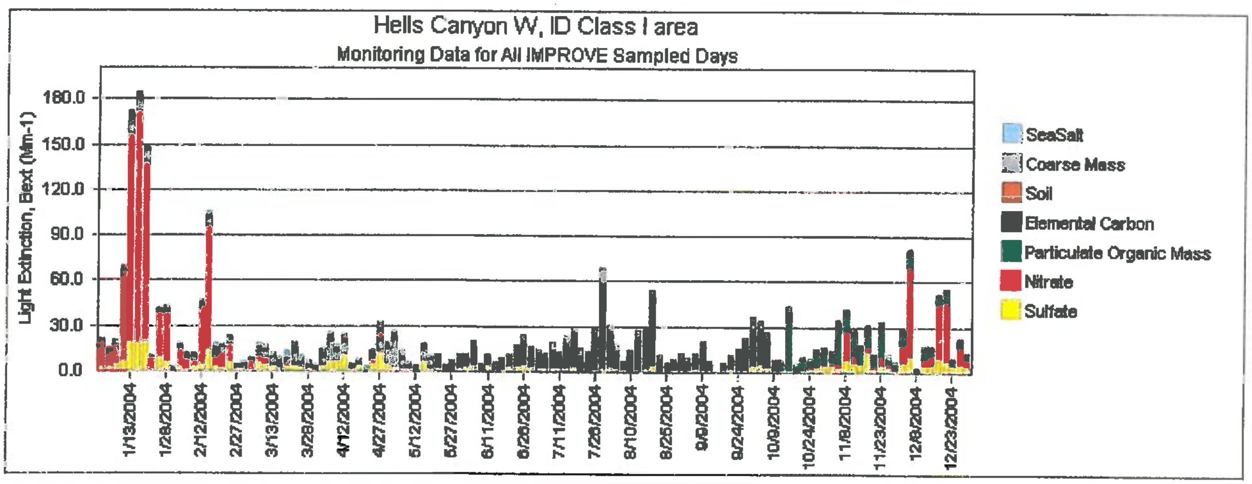


Figure 11 Light extinction (Mm-1) based on measured aerosol concentrations at Hells Canyon IMPROVE site, 2004.

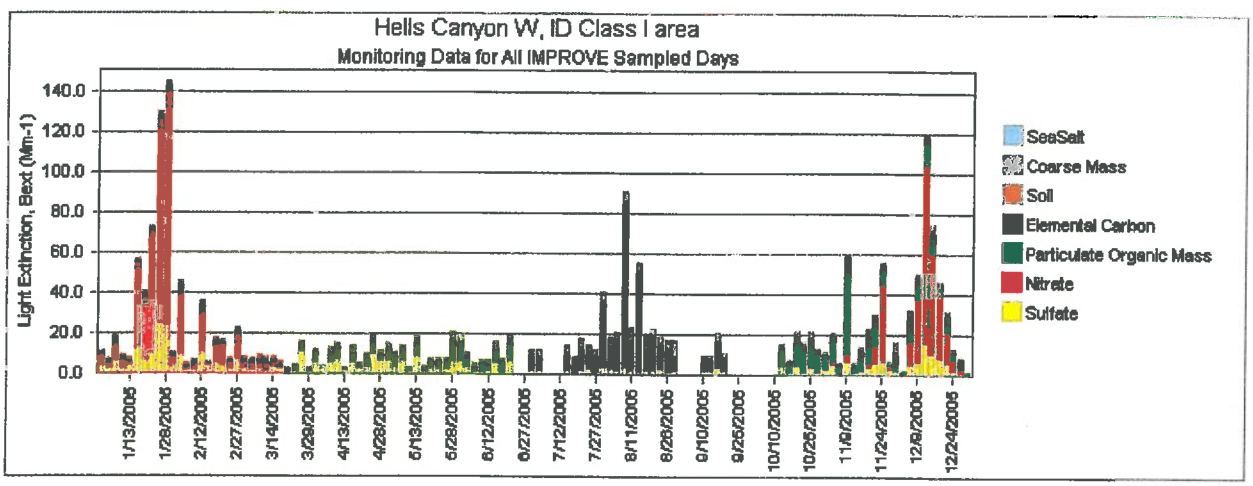


Figure 12 Light extinction (Mm-1) based on measured aerosol concentrations at Hells Canyon IMPROVE site, 2005.

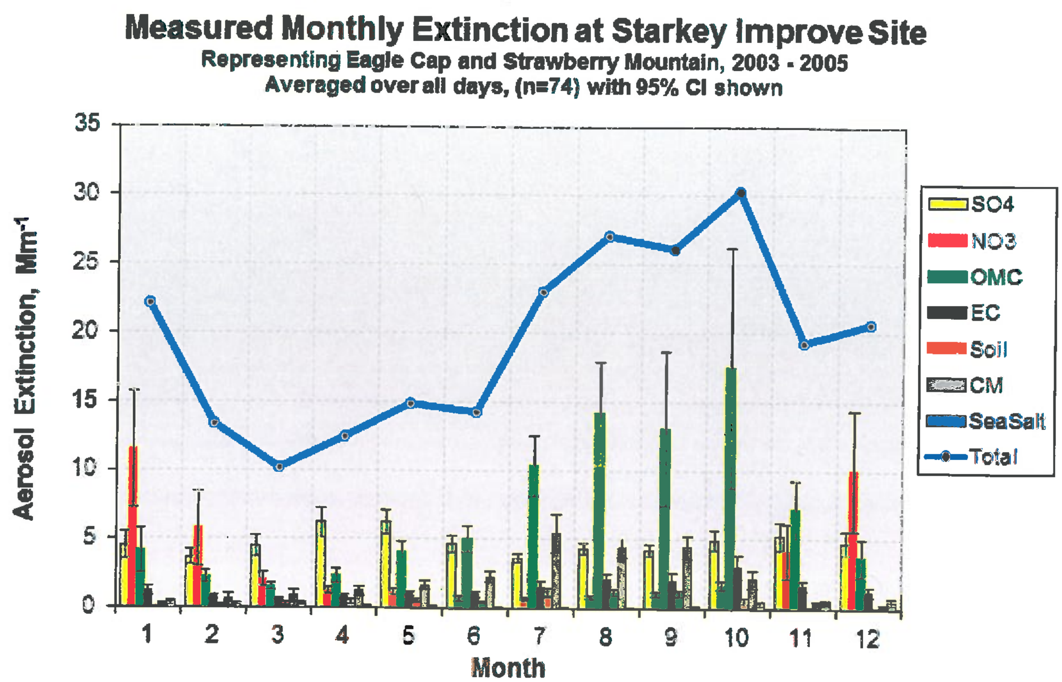


Figure 13 Light extinction (Mm-1) based on measured aerosol concentrations at Starkey IMPROVE Site, All Days, 2003 - 2005.

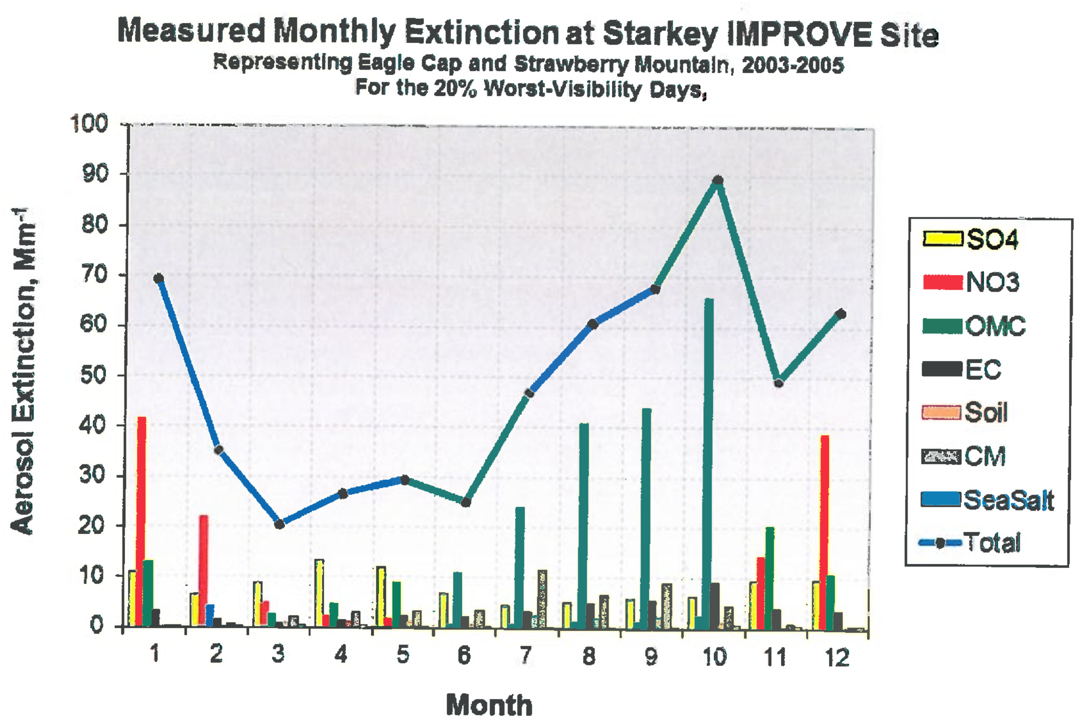


Figure 14 Light extinction (Mm-1) based on measured aerosol concentrations at Starkey IMPROVE Site, for 20% Worst Visibility Days, 2003-2005

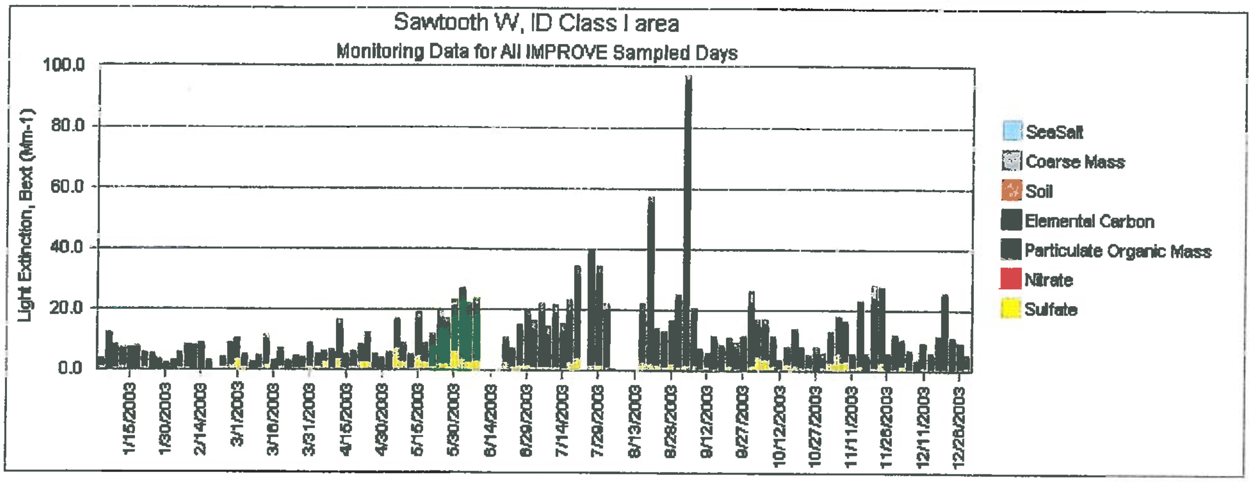


Figure 15 Light extinction (Mm-1) based on measured aerosol concentrations at Sawtooth Wilderness IMPROVE site, 2003.

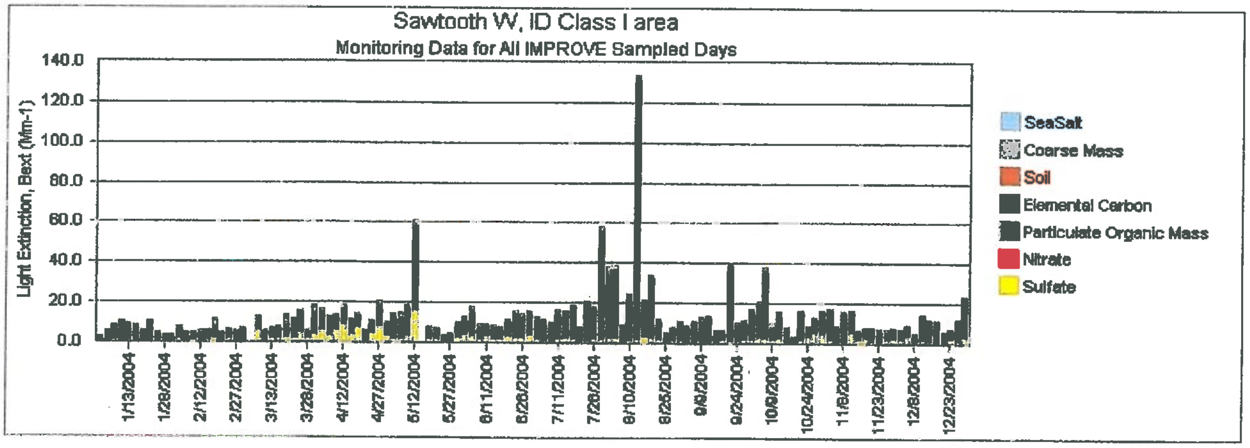


Figure 16 Light extinction (Mm-1) based on measured aerosol concentrations at Sawtooth Wilderness IMPROVE site, 2004.

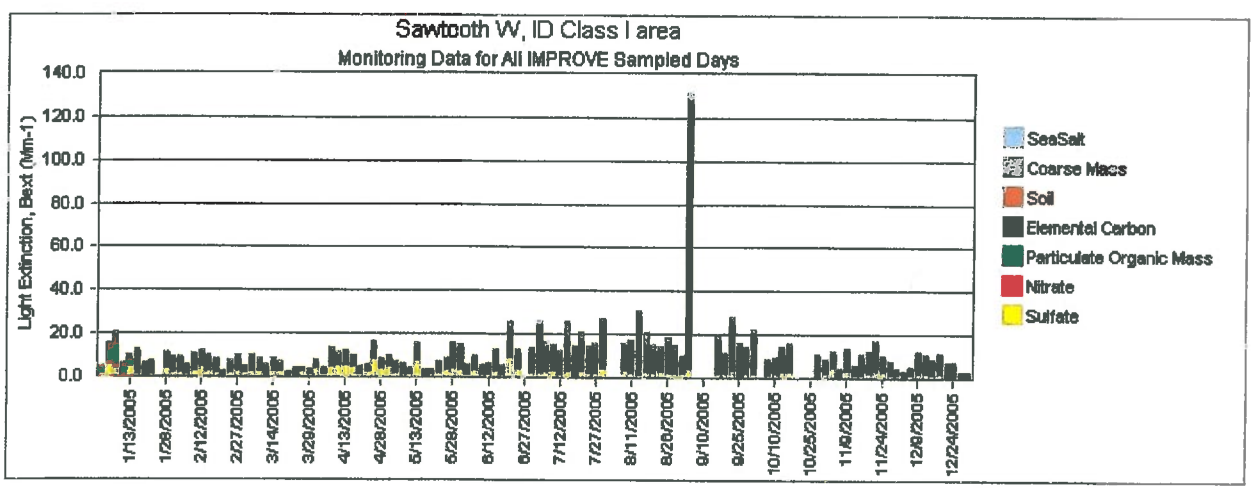


Figure 17 Light extinction (Mm-1) based on measured aerosol concentrations at Sawtooth Wilderness IMPROVE site, 2005.

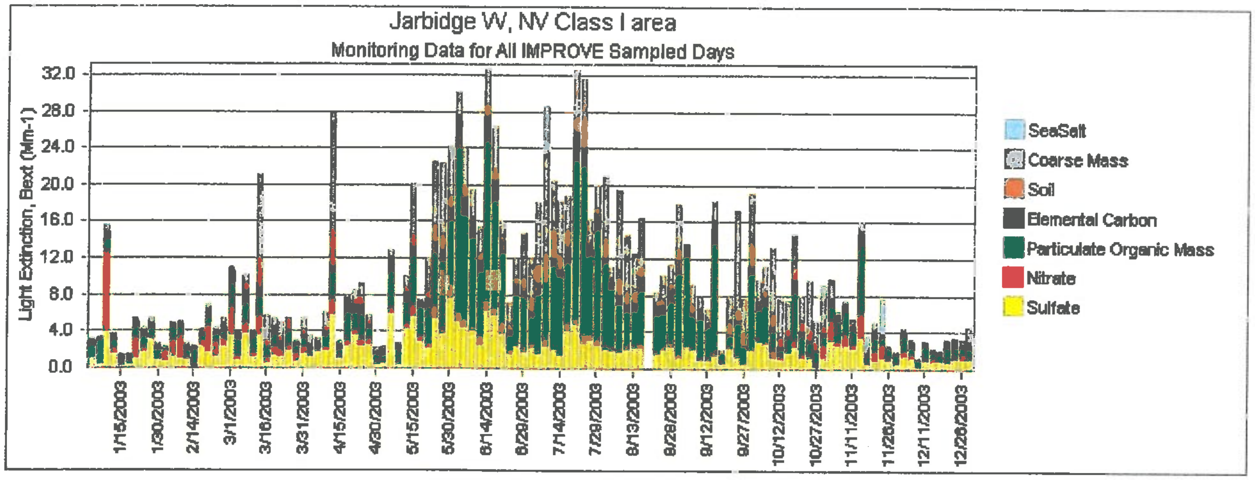


Figure 18 Light extinction (Mm-1) based on measured aerosol concentrations at Jarbidge Wilderness IMPROVE site, 2003.

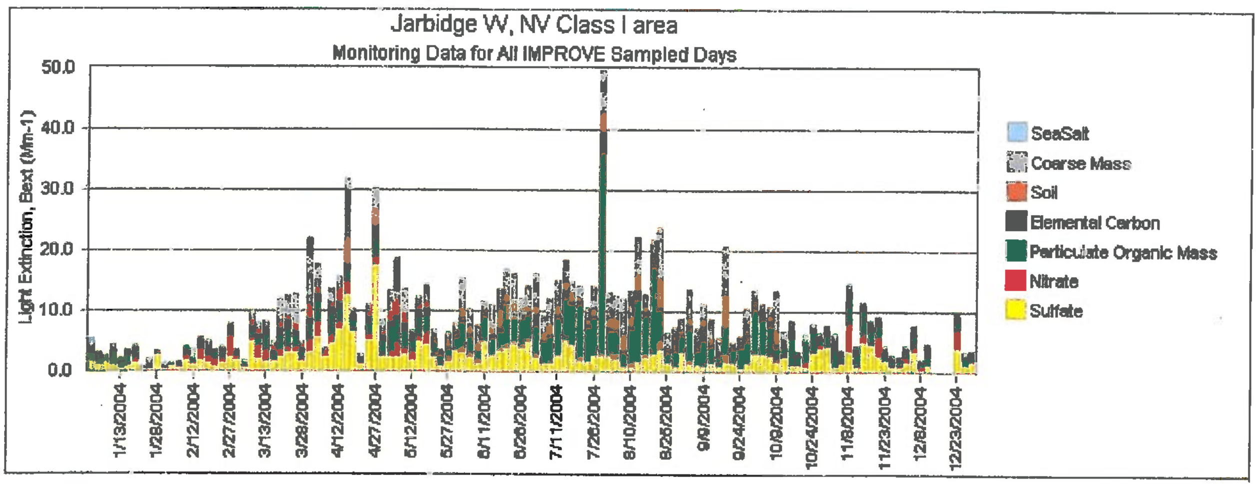


Figure 19 Light extinction (Mm-1) based on measured aerosol concentrations at Jarbidge Wilderness IMPROVE site, 2004.

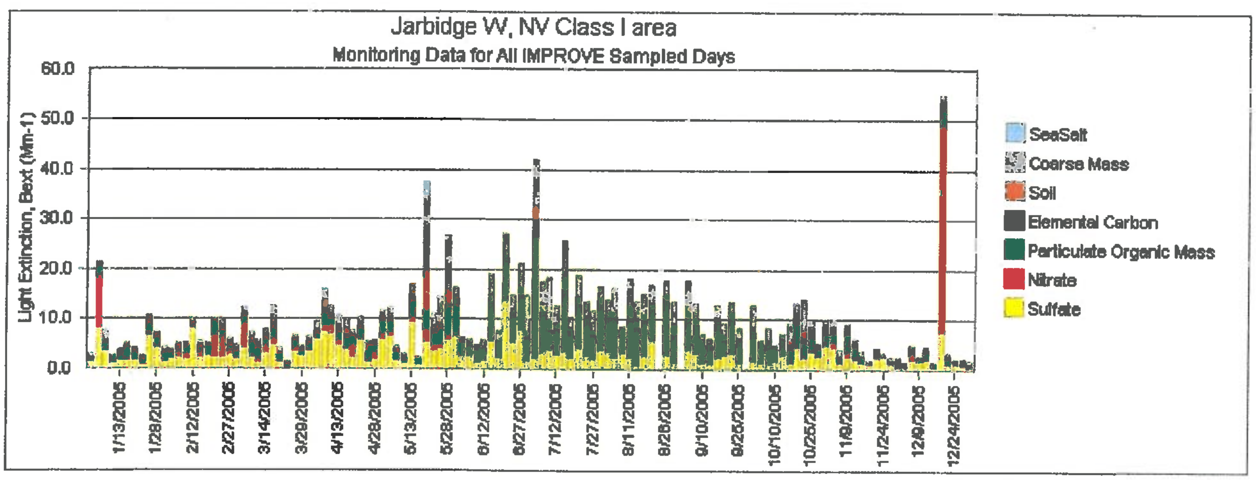


Figure 20 Light extinction (Mm-1) based on measured aerosol concentrations at Jarbidge Wilderness IMPROVE site, 2005.

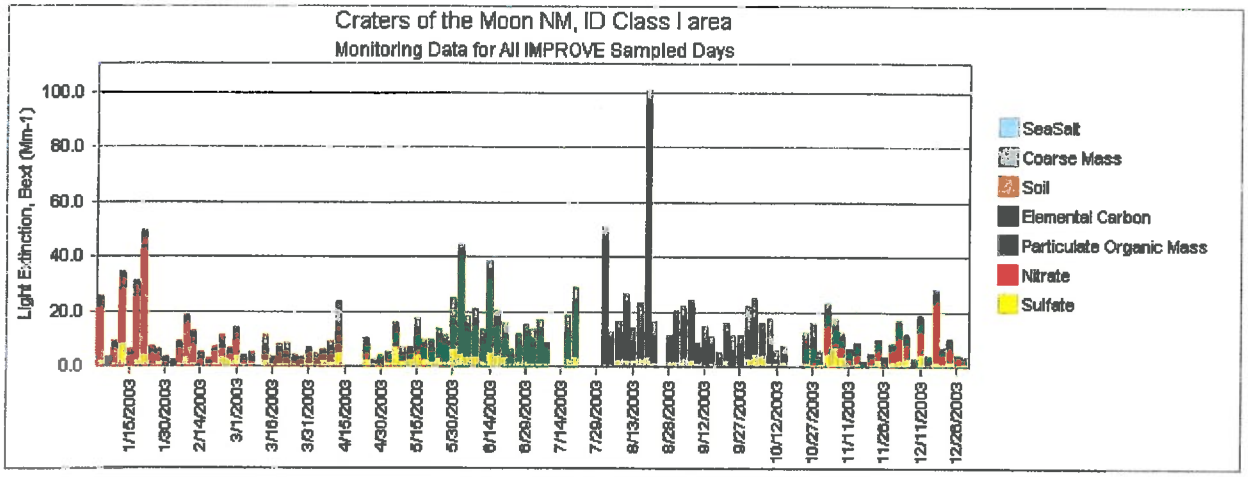


Figure 21 Light extinction (Mm-1) based on measured aerosol concentrations at Craters of the Moon Wilderness IMPROVE site, 2003.

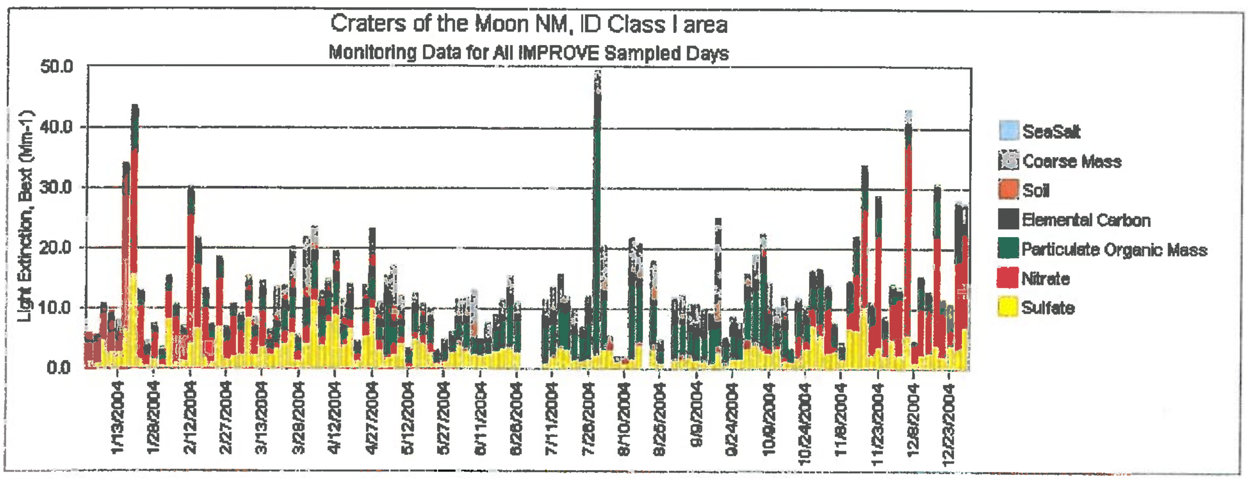


Figure 22 Light extinction (Mm-1) based on measured aerosol concentrations at Craters of the Moon Wilderness IMPROVE site, 2004.

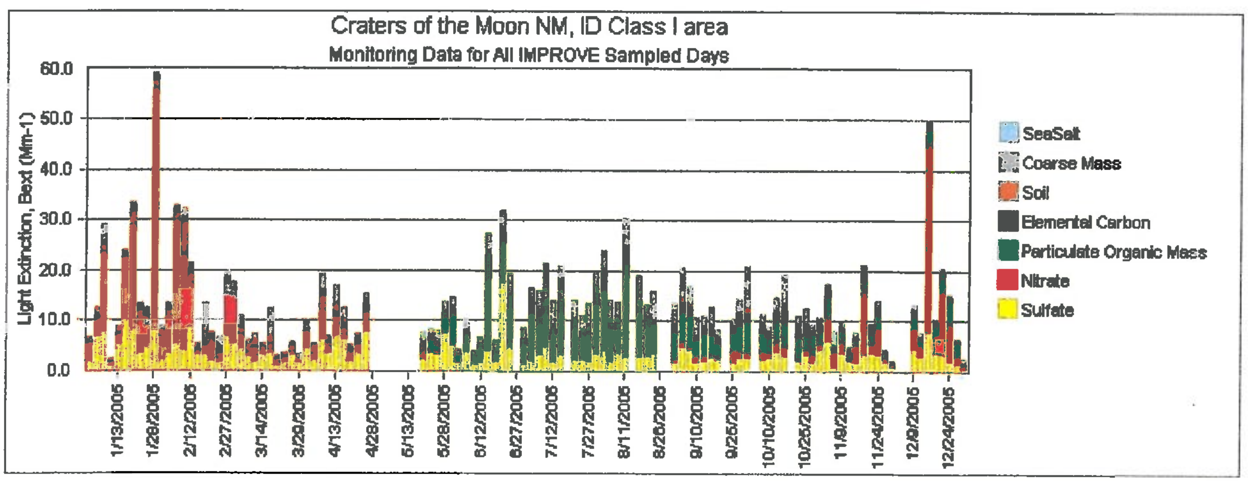


Figure 23 Light extinction (Mm-1) based on measured aerosol concentrations at Craters of the Moon Wilderness IMPROVE site, 2005.

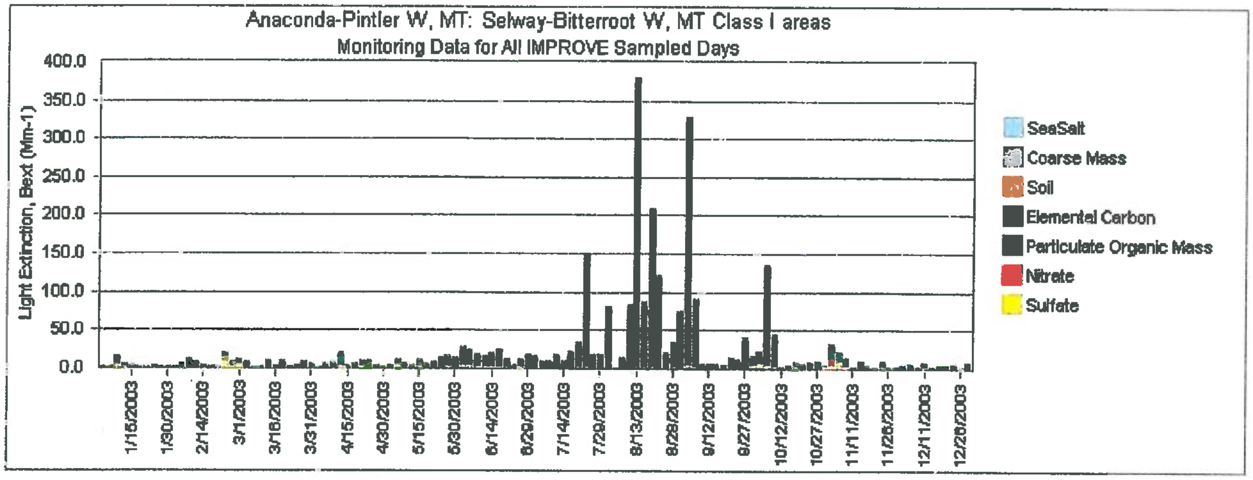


Figure 24 Light extinction (Mm-1) based on measured aerosol concentrations at Selway-Bitterroot Wilderness IMPROVE site, 2003.

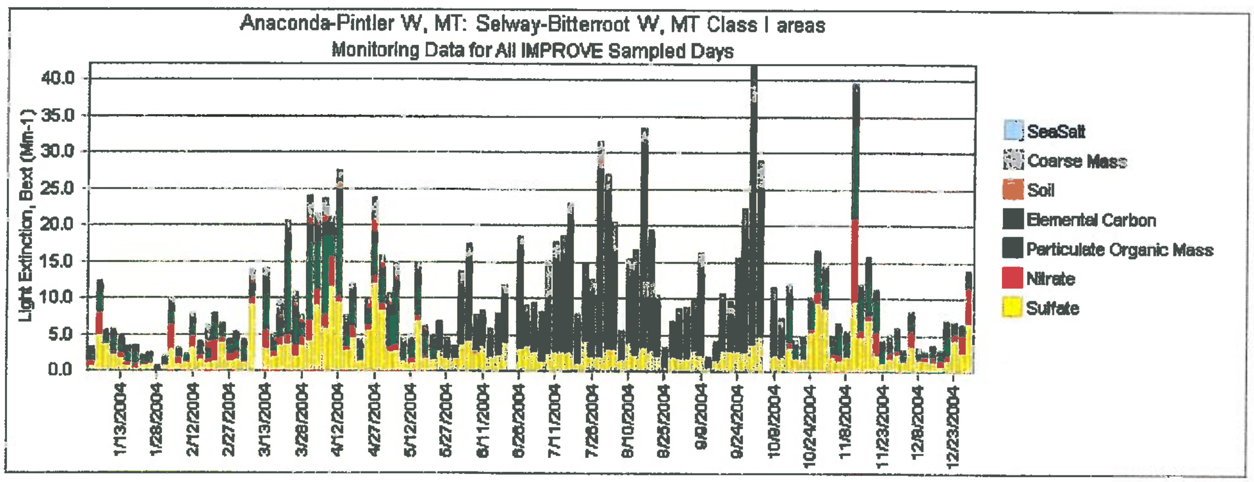


Figure 25 Light extinction (Mm-1) based on measured aerosol concentrations at Selway-Bitterroot Wilderness IMPROVE site, 2004.

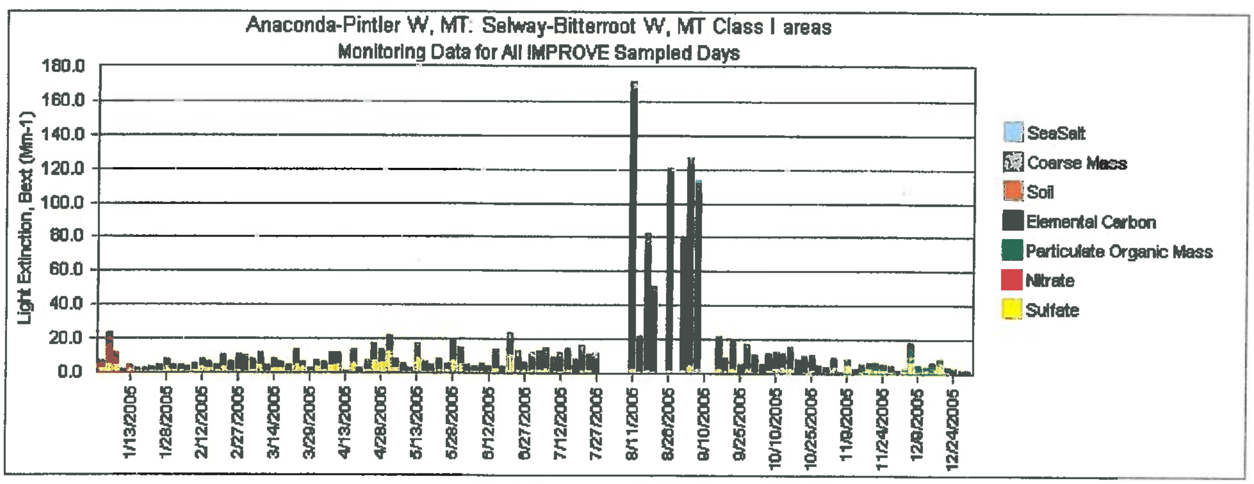


Figure 26 Light extinction (Mm-1) based on measured aerosol concentrations at Selway-Bitterroot Wilderness IMPROVE site, 2005.

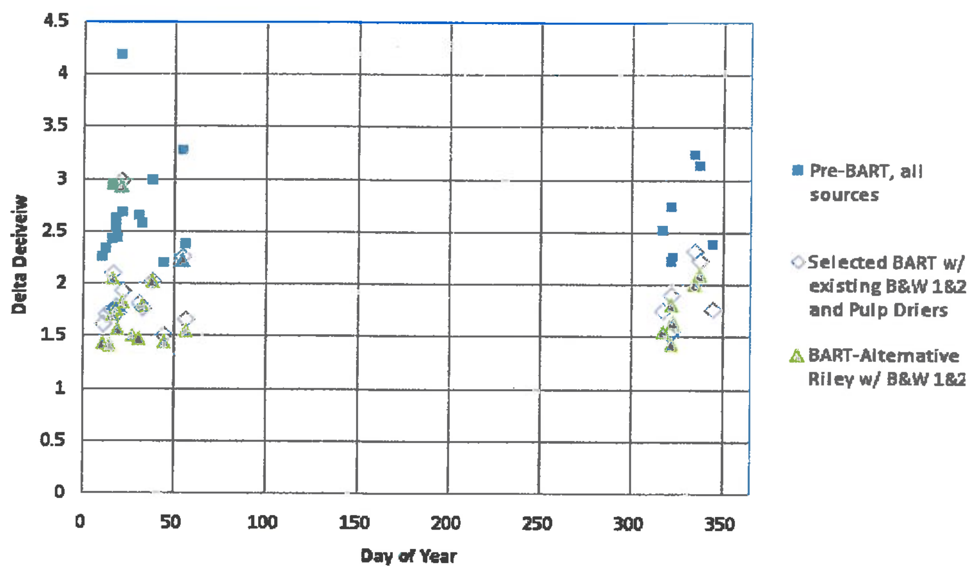


Figure 27 Seasonal variation in the modeled three-year highest 22 impacted days at Eagle Cap Wilderness for the pre-BART "Alternative Benchmark", selected "BART", and "BART Alternative" Scenarios.

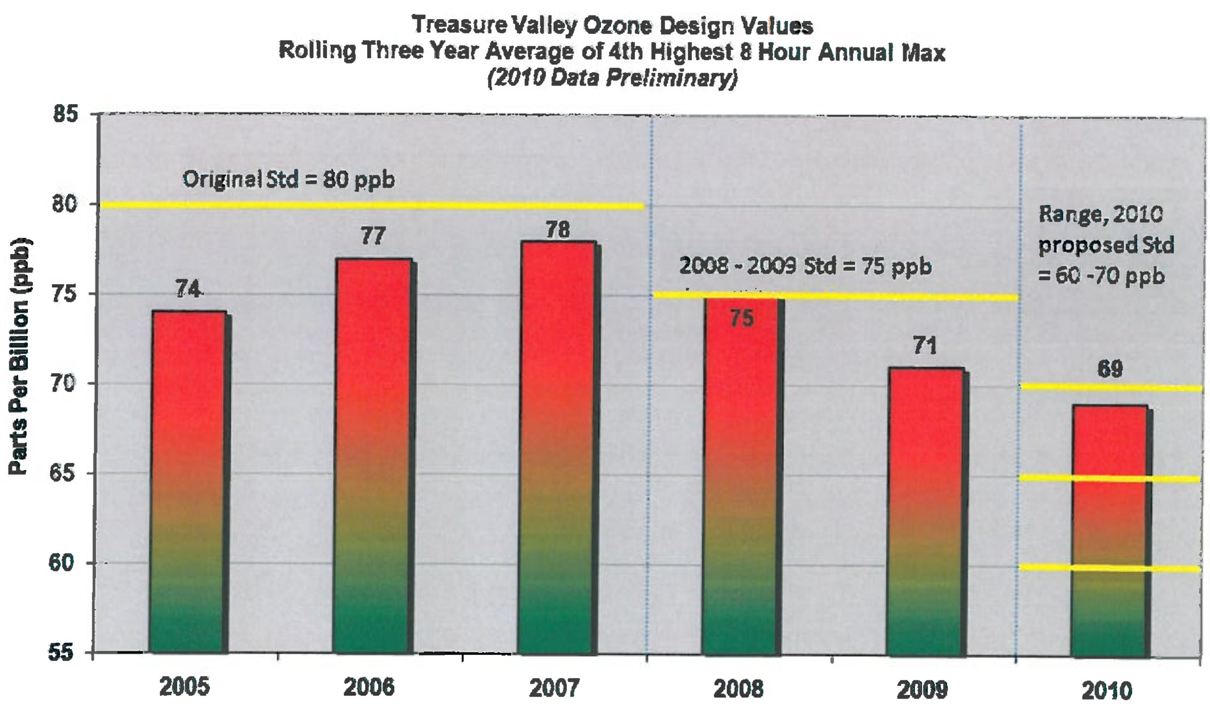


Figure 28 History of Treasure Valley Ozone Design Values and NAAQS.

APPENDIX C – INITIAL BART TIER II OPERATING PERMIT

Air Quality TIER II OPERATING PERMIT State of Idaho Department of Environmental Quality	**PERMIT No.:** T2-2009.0105 **FACILITY ID No.:** 027-00010 **AQCR:** 64 **CLASS:** A **ZONE:** 11 **SIC:** 2063 **NAICS:** 311313 **UTM COORDINATE (km):** 534.5, 4828.0

1. PERMITTEE The Amalgamated Sugar Company LLC – Nampa Factory			
2. PROJECT Tier II operating permit – required by DEQ to ensure compliance with applicable BART standards			
3. MAILING ADDRESS P.O. Box 8787	**CITY** Nampa	**STATE** ID	**ZIP** 83653-8787
4. FACILITY CONTACT Glen Patrick	**TITLE** Plant Environmental Manager	**TELEPHONE** (208) 468-6883	
5. RESPONSIBLE OFFICIAL Kent Quinney	**TITLE** Plant Manager	**TELEPHONE** (208) 466-3541	
6. EXACT PLANT LOCATION 138 W. Karcher Ave., Nampa, Idaho		**COUNTY** Canyon	
7. GENERAL NATURE OF BUSINESS & KINDS OF PRODUCTS Beet sugar manufacturing			

8. PERMIT AUTHORITY

This permit is issued according to the Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01.400 through 410, and pertains only to emissions of air contaminants regulated by the state of Idaho and to the sources specifically allowed to be operated by this permit.

Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

Morrie Lewis

MORRIE LEWIS, PERMIT WRITER
DEPARTMENT OF ENVIRONMENTAL QUALITY

Mike Simon

MIKE SIMON, STATIONARY SOURCE PROGRAM MANAGER
DEPARTMENT OF ENVIRONMENTAL QUALITY

Date Issued:	**September 7, 2010**
Date Modified/Revised:	
Date Expires:	**September 7, 2015**

MS/ML

Table of Contents

Acronyms, Units, and Chemical Nomenclature

AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
FGD	flue gas desulfurization
fpm	feet per minute
gpm	gallons per minute
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
LNB	low NO_X burner system
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
OFA	over-fired air
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration of air quality
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
TAP	toxic air pollutants
TASCO	The Amalgamated Sugar Company, LLC
T/hr	tons per hour
U.S.C.	United States Code
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1. TIER II OPERATING PERMIT SCOPE

Purpose

1.1 The purpose of this Tier II operating permit is to establish Best Available Retrofit Technology (BART) emission standards and requirements for the Riley Boiler in accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.401.03.

Regulated Sources

1.2 The following Regulated Emission Point Sources Table lists all sources of regulated emissions in this permit:

REGULATED EMISSION POINT SOURCES TABLE

Permit Section	Source Description	Emissions Controls
2 & 3	<u>Riley Boiler (S-B3)</u> Unit number: S-B3 Installation Date: 1969 Rated steam capacity: 250,000 lb steam/hr Maximum capacity: 350 MMBtu/hr Maximum operation: 8,760 hr/yr Fuel types: coal, natural gas	<u>Baghouse (A-B3)</u> Manufacturer: Envirotech Corp. Control efficiency: ≥99.0% for PM BART for PM <u>Spray dry flue gas desulfurization system</u> Reagent: Lime or limestone Control efficiency: 80-90% for SO_2 BART for SO_2 <u>Low NO_X burner system with over-fired air</u> Control efficiency: ≥50% for NO_X BART for NO_X
2 & 4	<u>Pulp dryers (S-D1, S-D2, and S-D3)</u>	<u>Permanent shutdown</u>

2. FACILITY-WIDE CONDITIONS

Obligation to Comply

2.1 Receiving a Tier II operating permit shall not relieve any owner or operator of the responsibility to comply with all applicable local, state, and federal rules and regulations, in accordance with IDAPA 58.01.01.406.

Incorporation of Federal Requirements by Reference

2.2 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein, in accordance with IDAPA 58.01.01.107. Documents include, but are not limited to:

- Protection of Visibility, 40 CFR Part 51, Subpart P, Section 308 – Best Available Retrofit Technology (BART) requirements
- Compliance Assurance Monitoring (CAM), 40 CFR Part 64

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as BART and CAM), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments.

DEQ Address

2.3 Any reporting required by this permit, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, notifications of intent to test, testing reports, or compliance certifications, shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete. Any reporting required by this permit shall be submitted to the following address:

Air Quality Permit Compliance
Department of Environmental Quality
Boise Regional Office
1445 N. Orchard
Boise, ID 83706

Phone: (208) 373-0550
Fax: (208) 373-0287

3. RILEY BOILER BART

3.1 Process Description

The Riley Boiler is fired by pulverized coal and/or natural gas, and is used to supply steam and generate electricity for processing of sugar beets into sugar and byproducts, including animal feed at the Nampa facility.

3.2 Emission Control Description

The existing baghouse (Unit No. A-B3) manufactured by Envirotech Corp. is used for the control of particulate matter (PM) emissions from the Riley Boiler.

A spray dry flue gas desulfurization (FGD) system has been required for the control of sulfur dioxide (SO_2) emissions from the Riley Boiler. In a spray dry FGD system, the flue gas is introduced into a tower and contacts an atomized spray of lime slurry, which absorbs and neutralizes the SO_2.

A low NO_X burner system (LNB) with over-fired air has been required for the control of nitrogen oxides (NO_X) emissions from the Riley Boiler. Low NO_X combustion with over-fired air utilizes fuel and air mixing optimization and staged combustion techniques to minimize thermal NO_X formation.

Compliance Dates

3.3 BART 40 CFR 51.308, Subpart P – BART Installation and Operation Due Date

The permittee shall install and operate BART or a DEQ-approved BART alternative on each source subject to BART as expeditiously as practicable, but in no event later than five (5) years after approval of the implementation plan, in accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv).

The permittee may submit a request to obtain a DEQ-approved BART alternative and to revise this permit in accordance with IDAPA 58.01.01.404.04. DEQ will process the request in accordance with IDAPA 58.01.01.404. The request must be submitted timely such that any revisions to this permit and the corresponding revision to the Regional Haze SIP are approved prior to the BART installation and operation due date (as defined in this permit condition). Pursuant to Section 110(k)(2) of the Clean Air Act, EPA has 12 months to act on a requested SIP revision.

Emissions Limits

3.4 BART 40 CFR 51.308, Subpart P – BART and BART Alternative Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in the following Riley Boiler BART and BART Alternative Emission Limits Table, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e):

RILEY BOILER BART AND BART ALTERNATIVE EMISSION LIMITS TABLE

Source Description	PM	SO_2	NO_X
	lb/hr [(a,b)]	lb/hr [(a,b)]	lb/hr [(a,c)]
Riley Boiler (S-B3)	14	115	186

(a) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

(b) BART emission rate limit in accordance with 40 CFR 51.308(e).

(c) BART alternative emission rate limit in accordance with 40 CFR 51.308(e)(2).

3.5 CO Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in the following Riley Boiler CO Emission Limits Table, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e):

RILEY BOILER CO EMISSION LIMITS TABLE

Source Description	CO	
	lb/hr [(a)]	T/yr [(b)]
Riley Boiler (S-B3)	25.8	113

(a) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

(b) Tons per any consecutive 12-calendar month period.

Operating Requirements

3.6 BART 40 CFR 51.308, Subpart P – Baghouse Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), and at all times the Riley Boiler is fired with coal, the permittee shall operate a Baghouse (A-B3) to control PM emissions from the Riley Boiler to ensure compliance with the BART PM emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e). The baghouse need not be operated during periods when the Riley Boiler is being fired exclusively with natural gas.

3.7 BART 40 CFR 51.308, Subpart P – Spray Dry Flue Gas Desulfurization Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a spray dry flue gas desulfurization (FGD) system to control SO_2 emissions from the Riley Boiler and to ensure compliance with the BART SO_2 emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

3.8 BART 40 CFR 51.308, Subpart P – Low NO_X Burner Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a low NO_X burner system (LNB) in the Riley Boiler to reduce NO_X emissions and to ensure compliance with the BART NO_X emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

- The LNB shall have a maximum rated heat input capacity (highest heating value) of less than or equal to 350 MMBtu/hr, and shall combust only natural gas and/or coal fuel.
- If operation of the LNB with OFA in the Riley Boiler is expected to result in an emissions increase, the permittee shall submit the required preconstruction compliance demonstrations (Permit Condition 3.18).

3.9 BART 40 CFR 51.308, Subpart P – Maintenance of BART Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05 and 40 CFR 51.308(e)(1)(v).

Monitoring and Recordkeeping Requirements

3.10 Baghouse Pressure Differential Monitoring

The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the pressure drop across each of the baghouses, in inches water gauge. The pressure drop shall be recorded once per day while the boilers are in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.11 Spray Dry FGD Adiabatic Approach Temperature Monitoring

The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the adiabatic approach temperature for the spray dry FGD spray tower in degrees Fahrenheit. The temperature differential shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.12 Primary and Over-Fired Air Flow Monitoring

The permittee shall install, calibrate, and maintain measuring devices to continuously monitor the primary and over-fired air flow rates into the Riley Boiler, in feet per minute. The flow rate shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.13 Operation and Maintenance Manuals

Within 60 days after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall develop and submit to DEQ an Operation and Maintenance (O&M) manual for review and comment at the address provided (Permit Condition 2.3). Any changes to the O&M manual shall be submitted to DEQ for review and comment within 15 days of the change.

- The O&M manual shall describe for each of the control equipment described in the Regulated Emission Point Sources Table (Permit Condition 1.2) procedures that will be followed to ensure compliance with BART emission limits (Permit Condition 3.4), CO emission limits (Permit Condition 3.5), the maintenance of BART equipment requirement (Permit Condition 3.9), the control equipment maintenance and operation general provision (General Provision 2), and the manufacturer's specifications. The O&M manual shall be a permittee developed document based upon, but independent from, the manufacturer supplied operating manual(s).
- The permittee shall operate the control equipment in accordance with the O&M manual. The procedures specified in the O&M manual are incorporated by reference into this permit and are enforceable permit conditions. The O&M manual and copies of any manufacturer's manual(s) and recommendations shall remain on site at all times and shall be made available to DEQ representatives upon request.
- At a minimum, the manufacturer's recommended values that shall be maintained for each of the following operating parameters shall be included in the manual:
    - Baghouse minimum and maximum pressure drop, in inches of water (iwg);
    - Spray dry FGD minimum slurry flow rate, in gallons per minute (gpm);
    - Spray dry FGD adiabatic approach temperature, in degrees Fahrenheit (°F) above the adiabatic saturation temperature;

- LNB minimum and maximum flow rates for both primary and over-fired airflow, in feet per minute (fpm); and
- Requirements to monitor and record the parameters listed above accordance with the frequency recommended by the manufacturer, and at a minimum each day that the Riley Boiler is operated.

Performance Testing Requirements

3.14 Initial Performance Tests

- No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3), performance tests shall be conducted on the Riley Boiler stack to demonstrate compliance with the following emission limits, in accordance with IDAPA 58.01.01.405 and IDAPA 58.01.01.157:
  - The BART PM emission limit in pounds per hour (Permit Condition 3.4);
  - The BART SO_2 emission limit in pounds per hour (Permit Condition 3.4);
  - The BART NO_X emission limit in pounds per hour (Permit Condition 3.4); and
  - The CO emission limit in pounds per hour (Permit Condition 3.5).
- Each performance test shall be conducted under the following conditions, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.405, IDAPA 58.01.01.157, and General Provision 6:
  - Emissions shall be measured while combusting coal fuel in the Riley Boiler.
  - Three separate test runs shall be conducted for each performance test.
  - Parameters shall be monitored and recorded as specified in the performance test monitoring and recordkeeping requirement (Permit Condition 3.16).

3.15 Periodic Performance Testing

Performance tests to determine PM, SO_2, NO_X, and CO emissions in pounds per hour from the Riley Boiler stack shall be conducted no less frequently than annually following the date of each required initial performance test, in accordance with IDAPA 58.01.01.405 and under the conditions required for the initial performance tests (Permit Condition 3.14), unless another testing frequency has been approved by DEQ.

3.16 Performance Test Monitoring and Recordkeeping

The permittee shall monitor and record the following during each performance test, unless otherwise approved by DEQ:

- Steam production rate of the Riley Boiler, in pounds per hour (lb steam/hr), once every 15 minutes;
- Coal feed rate to the Riley Boiler, in tons per hour (T/hr), once every 15 minutes (the coal feed rate may be determined using alternate relevant operational parameter(s) and a calculation method which has been approved by DEQ);
- Natural gas firing rate, in million standard cubic feet per hour (MMscf/hr), once every 15 minutes;
- Highest heating value and analysis results, including ash content, of the coal fired;
- Pressure drop across the baghouse during each test, in inches water gauge (iwg), once every 15 minutes;
- Spray dry FGD minimum slurry flow rate, in gallons per minute (gpm);
- Spray dry FGD adiabatic approach temperature, in degrees Fahrenheit (°F), once every 15 minutes; and

- LNB primary and over-fired air flow rates, in feet per minute (fpm), once every 15 minutes.

3.17 Performance Test Reporting

The permittee shall submit performance test reports to DEQ which include records of the monitoring required (Permit Condition 3.16) and in accordance with the performance testing general provision (General Provision 6). Performance test reports shall be submitted by the permittee to the DEQ address provided (Permit Condition 2.3).

Compliance Submittals and Notifications

3.18 Preconstruction Compliance Demonstrations

No later than 180 days prior to the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall submit information and modeling analyses demonstrating that installation and operation of BART will not cause or significantly contribute to a violation of any ambient air quality standards, in accordance with the procedures provided in IDAPA 58.01.01.200-228. This shall include the following, unless otherwise approved by DEQ:

- Demonstration of Preconstruction Compliance with Toxic Standards
- Demonstration of Preconstruction Compliance with National Ambient Air Quality Standards

3.19 CAM 40 CFR 64 and IDAPA 58.01.01.668.06.c – Documentation of Need for Improved Monitoring

No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3) and unless otherwise approved by DEQ, the permittee shall submit information to address monitoring changes in accordance with IDAPA 58.01.01.668.06.c, and in a Compliance Assurance Monitoring (CAM) plan relevant to the installation and operation of BART in accordance with the procedures in 40 CFR Part 64.

3.20 Submittal and Notification Requirements

Required compliance submittals and notifications (Permit Conditions 3.18 and 3.19) shall be submitted to the DEQ address provided (Permit Condition 2.3).

4. SOUTH PULP DRYER

Operating Requirements

4.1 BART 40 CFR 51.308, Subpart P – Shutdown of South Pulp Dryer

The permittee shall permanently shut down the South pulp dryer (S-D1).

Notification and Reporting Requirements

4.2 Pulp Dryer Shutdown Notification

Within 30 days after completing permanent shut down of the South pulp dryer (as required by Permit Condition 4.1), the permittee shall provide written notification to DEQ of the decision to permanently shut down the South pulp dryer. The notification shall include a description of the method used to ensure permanent shut down of the South pulp dryer.

5. SUMMARY OF EMISSION RATE LIMITS

The following table provides a summary of all emission rate limits required by this permit:

SUMMARY OF EMISSION RATE LIMITS

Source Description	PM	SO_2	NO_X	CO	
	lb/hr [a,c]	lb/hr [a,c]	lb/hr [a,c]	lb/hr [a]	T/yr [b]
Riley Boiler (S-B3) with BART	14	115	186	25.8	113

[a] Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.
[b] Tons per any consecutive 12-calendar month period.
[c] BART emissions rate in accordance with 40 CFR 51.308(e).

6. TIER II PERMIT TO OPERATE GENERAL PROVISIONS

General Compliance

1. The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the Rules for the Control of Air Pollution in Idaho. The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit and the Rules for the Control of Air Pollution in Idaho, and the Environmental Protection and Health Act, Idaho Code §39-101, et seq.

[Idaho Code §39-101, et seq.]

2. The permittee shall at all times (except as provided in the Rules for the Control of Air Pollution in Idaho) maintain in good working order and operate as efficiently as practicable, all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.405, 5/1/94]

3. Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules and regulations.

[IDAPA 58.01.01.406, 5/1/94]

Inspection and Entry

4. Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

   a. Enter upon the permittee's premises where an emissions source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;

   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

   c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

   d. As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

5. The permittee shall furnish DEQ written notifications as follows:

   a. A notification of the date of initiation of construction, within five working days after occurrence;

   b. A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

   c. A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date;

   d. A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and

e. A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.405, 5/1/94]

Performance Testing

6. If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

Within 30 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

7. The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Records of monitoring information shall include, but not be limited to the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.405, 5/1/94]

Excess Emissions

8. The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions due to startup, shutdown, scheduled maintenance, safety measures, upsets and breakdowns.
[IDAPA 58.01.01.130-136, 4/5/00]

Certification

9. All documents submitted to DEQ, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.
[IDAPA 58.01.01.123, 5/1/94]

False Statements

10. No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.
[IDAPA 58.01.01.125, 3/23/98]

Tampering

11. No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.
[IDAPA 58.01.01.126, 3/23/98]

Expiration and Renewal

12. This permit shall be renewable on the expiration date, provided the permittee submits an application for renewal to the Department and continues to meet all terms and conditions contained in the permit. The expiration of this permit will not affect the operation of the stationary source of facility during the administrative procedure period associated with the permit renewal process.
[IDAPA 58.01.01.404.04, 7/1/02]

Transferability

13. This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.404.05.
[IDAPA 58.01.01.404.05, 4/11/06]

APPENDIX D – BAGHOUSE O&M MANUAL

Operations & Maintenance Manual for:

Riley and B&W Boiler Baghouses

The Amalgamated Sugar Company

Nampa Facility

September, 2003
(revised October 2004)

Table of Contents

Introduction

In accordance with Permit Condition 2.15 of the Tier II Operating Permit (#027-00010), this Operations & Maintenance Manual (O&M Manual) outlines procedures that when implemented will ensure that the Riley and B&W Boiler Baghouses operate at optimal efficiency. The O&M Manual includes the following:

1) Introduction
2) General Description of the Control Equipment
3) Normal Operating Conditions
4) Upset Conditions and Corrective Procedures
5) Boiler Start-up, Shutdown procedures
6) Control Device Monitoring Program
7) Maintenance Procedures
    a. Daily Inspections and Maintenance
    b. Annual Maintenance
8) Record keeping

General Description of the Control Equipment

B&W Boilers Baghouse (Unit Number A-B1/2)

Particulate emissions from the two B&W Boilers are controlled using a Joy Baghouse. The baghouse was installed in 1974 as a retrofit project. It is located just west of the boiler house on an elevated platform. Flue gas is ducted from the boiler outlet through the baghouse to the stack. A bypass duct and damper is used to bypass the baghouse if necessary in an emergency situation,(i.e. baghouse blinded, boiler tube leak, etc).

An Operation and Maintenance Manual (attached), provided by BHA during a training session, was used as a guide for preparing this document.

Joy Baghouse Specifications:

Number of Bags	4,224
Type of Bags	BHA brand GL22 fiberglass bags
Air Permeability	30 to 60 CFM.
Operating Temperature Range	240 to 360 ° F. .
Finish	10% Teflon B.
Dimensions	5.25 " X 125.5"
Flow Rate	93,500 to 140,000 ACFM
Baghouse Differential Pressure	2 to 14 "WG
Air to Cloth Ratio	1.4 : 1 gross and 1.6 : 1 net.
Dust Removal	Reverse Air, with acoustic using 2 horns
Rotary airlocks	

Riley Boiler Baghouse (A-B3)

Particulate emissions from the Riley Boiler are controlled using a Envirotech Baghouse. The baghouse was installed in 1975 as a retrofit project. It is located just north of the boiler house on a mezzanine bridging the pulp dryer building and the boiler house. Flue gas is ducted from the boiler outlet through the baghouse to the B&W stack. A bypass duct and damper is used to bypass the baghouse if necessary in an emergency situation, (i.e. baghouse blinded, boiler tube leak, etc).

Envirotech Baghouse Specifications

Number of Bags	3920
Type of Bags	BHA brand GL26 fiberglass bags or equivalent
Air Permeability	30 to 60 CFM.
Operating Temperature Range	260 to 400 ° F.
Finish	Heat Cleaned with a Chemically Resistant Coating.
Dimensions	5.25" X 166"
Flow Rate	106,000 to 160,000 ACFM
Baghouse Differential Pressure	2 to 14 "WG
Air to Cloth Ratio	1.4 : 1 gross and 1.7: 1 net.
Dust Removal	Reverse Air, with acoustic using 2 horns
Tensioning	Conical Springs
Rotary Airlocks	

Normal Operating Conditions

Contaminated air entering the baghouse under negative pressure is distributed using an inlet baffle. The inlet baffle decreases inlet gas velocity, which improves distribution and reduces the impact of high velocity particles on filter bags.

Air flows from the bottom inside of the filter bag to the top outside of the filter bag effectively filtering particulate matter from the flow. As the bag porosity decreases from the build up of filtered particulates (filter cake), the differential pressure increases across the baghouse collector. The filter bags are periodically cleaned with reverse air that removes the collected dust allowing it to drop into a hopper. Dust removal is also enhanced with acoustic horns, which are located in the area between the filter bag columns. The dust is removed from the hoppers using air lock rotary gates and mixed with water, which is hydraulically conveyed to a settling pond. During beet campaign the water is mixed with flume water in the settling ponds, but during intercampaign the water is directed to a separate settling pond near the piling ground.

Upset Conditions and Corrective Procedures

The Company takes its environmental responsibilities very seriously. Upsets that can lead to excess emissions from the boiler stack are a very serious matter and must be managed quickly and efficiently. The following information should be used for properly responding to upset conditions that can lead to an excess emission:

Cause An upset condition has the potential to occur when one or more of the following conditions occur:

1) One of more bags have ruptured. This allows flyash to enter the clean air side of the baghouse and exhaust to the stack.

2) One or more bags have slipped off the mounting thimble.

3) Boiler tube leak that has the potential to blind the bag from excessive moisture.

4) Baghouse cleaning system has failed and collected dust is not removed properly.

5) Baghouse air lock system has failed.

6) Baghouse dust conveying system has failed.

Detection An upset condition that leads to a possible excess emission from the stack can be detected by either 1) Boiler House Operators during operation checks and shift inspections or by 2) alarmed bag leak detectors.

> **Note:** A leak large enough to cause a visual emission cannot normally be detected by monitoring baghouse differential pressure readings.

Corrective Action
To assist the operators with detecting leaking bags, a leak detection system has been installed in each baghouse. The leak detection system will alert operators of a leak and pinpoint the affected baghouse. To determine which baghouse module is has the leaking bags; the operator will shut down each bag house module until the leaking stops. The bags are then refitted or replaced and the module is placed back into service.

Reporting Upset conditions that lead to a visible emission from the boiler stack must be immediately reported to the Shift Supervisor or the Boiler Foreman who will determine if DEQ needs to be notified. The boiler foreman is certified to

Differential Pressure Drop Monitoring Differential pressure drop (DPD) is required to be monitored by the Tier II permit. DPD is measured by two independent measuring systems, manually using permanently mounted manometers (in the boiler control room) and electronically using a DP cell. The DP cells provide data to the plants data acquisition system where it is logged and archived for reporting requirements.

Note: A leak large enough to cause a visual emission cannot normally be detected by monitoring baghouse differential pressure. Bag leak detectors and VE's should be used for determining if upset conditions exist that can lead to an excess emission.

The range of differential pressure drop across both baghouses (measured individually) is from 2" H_2O gauge to 14" H_2O water gauge.

Bag Leak Detectors Bag leak detectors have been installed at the outlet of each baghouse to alarm when particulate levels indicate that a bag leak is probable (see photo below). This is an important tool that can provide additional information about the baghouse performance. **The BLD should not be used as a replacement for visual emissions inspections.**

Visual Emissions Visual emissions of the boiler stack are conducted by two independent inspections. The plant Environmental Manager conducts see, no see VE inspections twice a month at approximately two weeks apart. VE's are also checked each shift by boiler operators. The findings need to be documented in the Boiler Control Room Log. **If a visible plume is present notify the shift supervisor and boiler foreman immediately and take corrective action to resolve the problem! (see the "Upset Conditions and Corrective Action" section)**

Maintenance Procedures

Maintenance is an important component of proper operation of emission control equipment. TASCO has identified the following daily monthly and annual tasks to be completed to ensure proper operation of the baghouses

Daily Inspections and Maintenance

To ensure optimal efficiency of emission control equipment, the following inspection tasks will be completed each hour with any discrepancies documented in the boiler house log:

1. Inspect rotary gates and rams. Check that rams activate and operate smoothly and properly. Rotary gates need to cycle properly and remove flyash from the hopper.

During Juice Run the B&W is usually out of service and maintenance is performed.

Annual Maintenance List

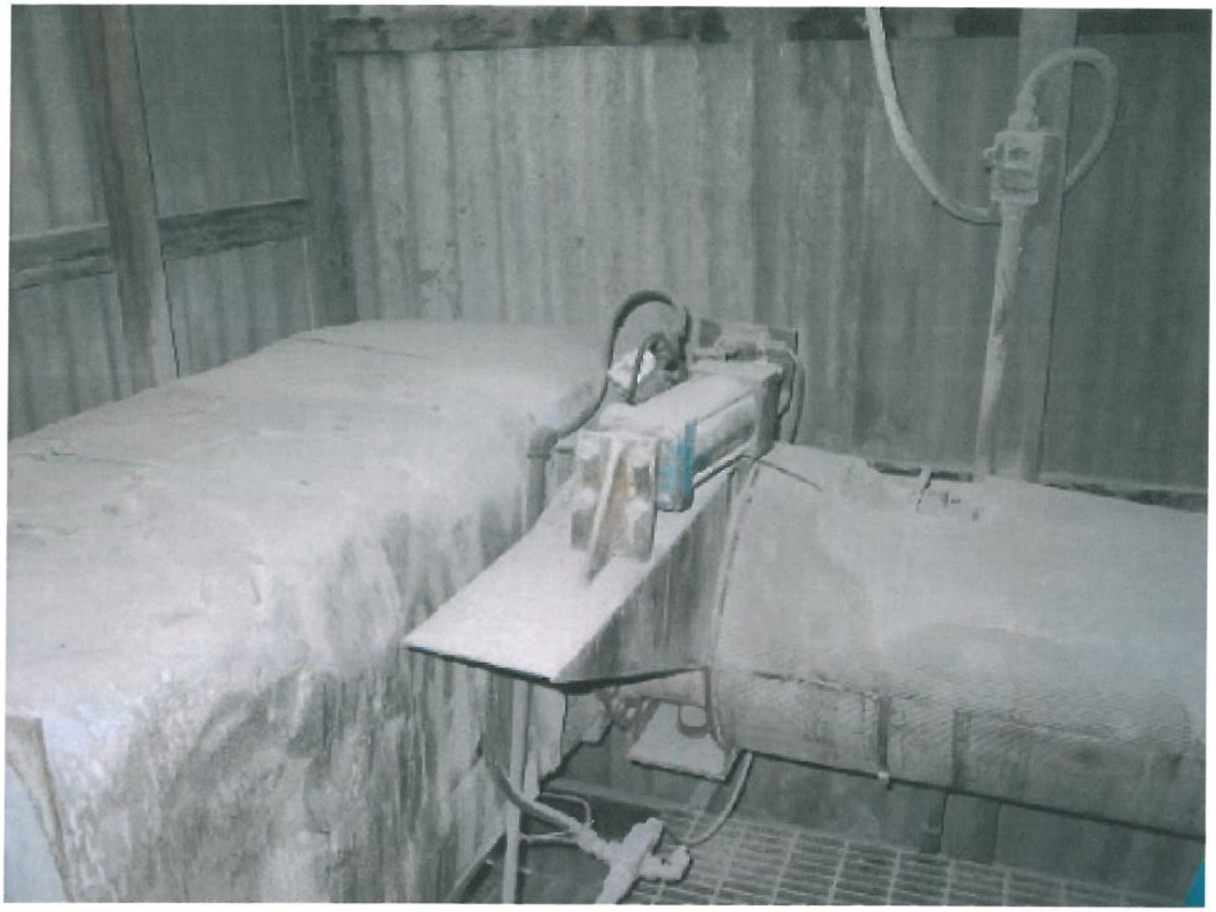
Annual maintenance presents the opportunity to conduct basic maintenance and system changes to resolve root cause issues. The following tasks have been identified as important annual inspection/maintenance items:

1) **Baghouse Housing.** Check for corrosion, warped panels and other damage that may lead to an air leak. Repair as necessary.

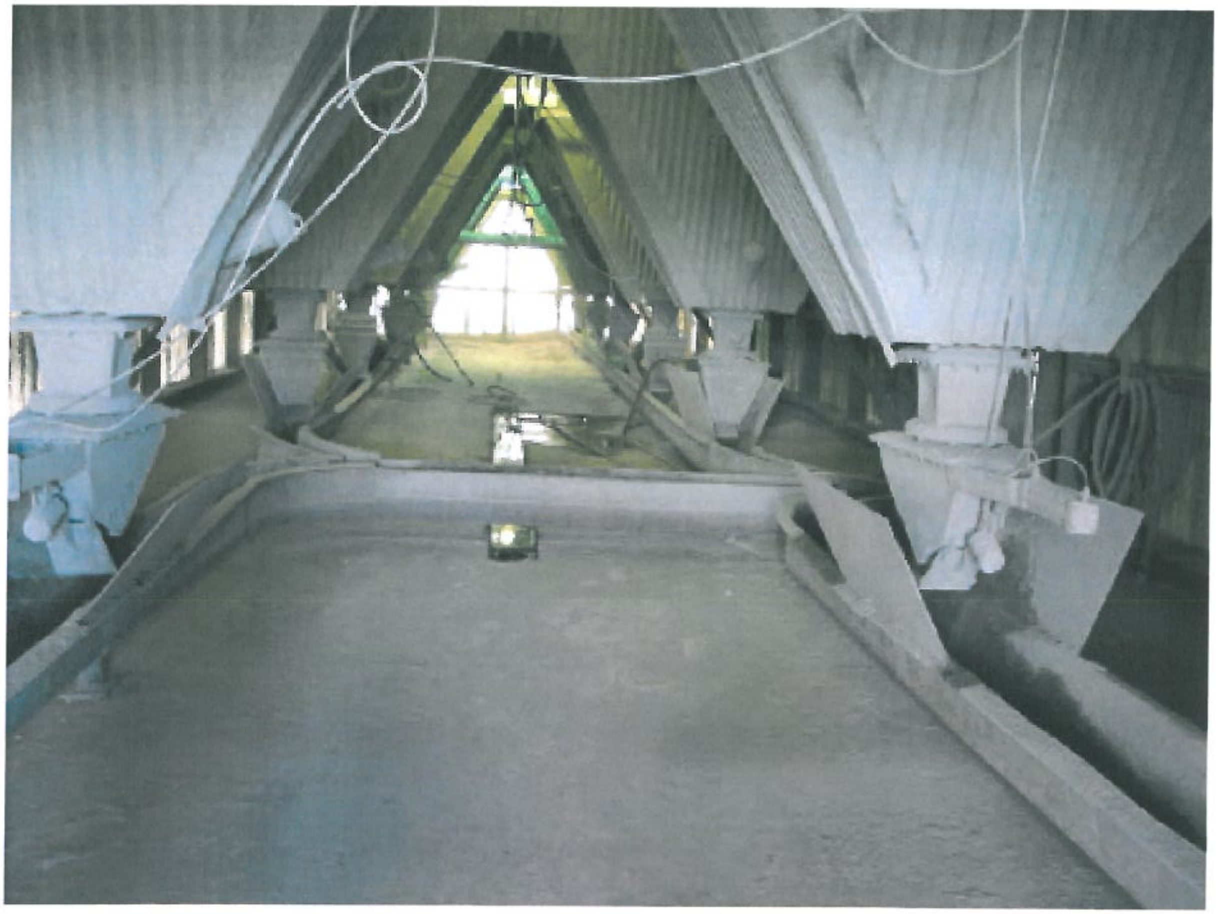
2) **Tube Sheets** Tube sheets need to be properly aligned, with no warp or corroded holes. They need to be in good operating condition. Repair as necessary if discrepancies are discovered.

3) **Filter Bag Connection Hardware** The hardware used to attach the filter bag needs to be in good condition and serviceable. Replace as necessary to ensure the filter bag will be attached properly.

4) **Filter Bags** Inspect filter bags and reject any that appear to have a hole, are damaged from abrasion or have lost strength because of heat excursion.



5) **Dampers and Air Rams** Ensure that air rams and dampers operate smoothly. Also check to ensure that dampers are positioned and seal properly.



6) **Hopper** Check for corrosion, warped panels and other damage that may lead to an air leakage or retention of dust. Hopper walls need to smoothly convey dust to the air lock system. Repair as necessary.

7) **Door Seals** Check door seals to ensure that they are in good repair and will seal properly. Replace as necessary

8) **Inlet Baffle** Inspect the baffle to ensure that they are in proper position. Also check for damage from abrasion and panel warp. Repair as necessary.

9) **Air Locks** Inspect airlocks to ensure that they are sealed, sequencing properly and operate smoothly. Repair as necessary.

10) **Air Horns** Inspect to ensure proper operation. Horns must be timed properly and develop the designed energy to remove dust. Check horn diaphragms to ensure that wear is within manufactures tolerances.

11) Reverse Air Fans Inspect reverse air fans to ensure that they provide sufficient air flow. Check bearings, and fan blades for wear and repair or replace as necessary.

12) Duct work and insulation Check for corrosion, warped panels and other damage that may lead to an air leak. Ensure that insulation is replaced after maintenance and that it is serviceable condition. Repair as necessary

13) Bypass Louvers Inspect bypass louvers to ensure proper damper seal. Check for corrosion, warped panels and other damage that may lead to air leakage past the damper.

14) Stack Insect gas path and breech to stack for corrosion, cracking and other damaged. Clean the stack breech and ductwork and repair as necessary.

Record Keeping

Record Keeping is a specific requirement in the Tier II permit. Record keeping is important to demonstrate that operational information and maintenance is completed as required in the Air Permit. As a minimum the following information will be collected and retained for up to five years:
Operations

1) The baghouse pressure drop will be recorded at least once per week during baghouse operation and archived in facility files.

Maintenance
1. All Baghouse Maintenance Performed.
2. All calibration information for baghouse control instrumentation