Statement of Basis

Tier I Operating Permit No. T1-2012.0030
Project ID 61058

Blackfoot Facility of Basic American Foods, a Division of Basic American, Inc.
Blackfoot, Idaho

Facility ID 011-00012

Draft for Facility Review

DRAFT XX, 2013

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Permit Writer

The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

ASTM	American Society for Testing and Materials
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gr/dscf	grains (1 lb = 7,000 grains) per dry standard cubic foot
HAP	hazardous air pollutants
hr/yr	hours per consecutive 12 calendar month period
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
MRRR	Monitoring, Recordkeeping and Reporting Requirements
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
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
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
Rules	*Rules for the Control of Air Pollution in Idaho*
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T1	Tier I operating permit
TAP	toxic air pollutants
ULSD	ultra low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compound

2. INTRODUCTION AND APPLICABILITY

Blackfoot Facility of Basic American Foods, A Division of Basic American, Inc. (BAF) is a manufacturer of dried food products, and is located at 415 West Collins Road, Blackfoot. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit PM_{10}, NO_x, CO, and SO_2 above the major source threshold of 100 tons-per-year and has the potential to emit over 100,000 tons-per-year CO_2 equivalent of greenhouse gas pollutants.

IDAPA 58.01.01.362 requires that as part of its review of the Tier I application, DEQ shall prepare a technical memorandum (i.e. statement of basis) that sets forth the legal and factual basis for the draft Tier I operating permit terms and conditions including reference to the applicable statutory provisions or the draft denial. This document provides the basis for the draft Tier I operating permit for BAF.

The format of this Statement of Basis follows that of the permit with the exception of the facility's information discussed first followed by the scope, the applicable requirements and permit shield, and finally the general provisions.

BAF's Tier I operating permit is organized into sections. They are as follows:

Section 1 - Tier I Operating Permit Scope

The scope describes this permitting action.

Section 2 - Facility-Wide Conditions

The Facility-wide Conditions section contains the applicable requirements (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each permit condition follows the permit condition.

Sections 3 through 10 - Emissions Unit/Source Name

The emissions unit-specific sections of the permit contain the applicable requirements that specially apply to each regulated emissions unit. Some requirements that apply to an emissions unit (e.g. opacity limits) may be contained in the facility-wide conditions. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each applicable requirement immediately follows the applicable requirement.

Section 11 - Compliance Schedule

A compliance schedule will be in the permit to address any sources not in compliance with an applicable requirement at the time of permit issuance.

Sections 12 and 13 - Non-applicable Requirements and Insignificant Activities

This section lists those requirements that the applicant has requested as non-applicable, and DEQ proposes to grant a permit shield in accordance with IDAPA 58.01.01.325.

If requested by the applicant, this section also lists emissions units and activities determined to be insignificant activities based on size or production as allowed by IDAPA 58.01.01.317.01.b.

Section 14 - General Provisions

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I sources. These conditions have been reviewed by EPA and contain all terms required by IDAPA 58.01.01 et al as well as requirements from other air quality laws and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and the rule or permit, the rule or permit shall govern.

3. FACILITY INFORMATION

Facility Description

The BAF Plant includes a food dehydrating plant and a co-located research and development laboratory related to vegetable dehydrating and product development. The Blackfoot plant produces dehydrated food products using a variety of drying and dehydration processes. Products are dried by contact with heated air. Drying air is heated either by direct-firing with natural gas or indirectly using steam heat exchangers. Steam for plant operations is provided by Boiler Numbers 1, 2, and 3.

Facility Permitting History

Tier I Operating Permit History - Previous 5-year permit term November 20, 2007 to November 20, 2012

The following information is the permitting history of this Tier I facility during the previous five-year permit term which was from to November 20, 2007. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

November 20, 2007	T1-060315, Permitting action description, Permit status (S)

Underlying Permit History - Includes every underlying permit issued to this facility

The following information is the comprehensive permitting history of all underlying applicable permits issued to this Tier I facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

December 24, 1975	PTC Letter, issued December 24, 1975 (A)
November 12, 1982	PTC Letter, issued November 12, 1982 (A)
April 27, 1995	PTC No. 011-000012, issued April 27, 1995 (S)
December 11, 2002	Initial Tier I Operating Permit No. 011-00012, issued December 11, 2002 (S)
March 22, 2004	PTC No. P-040300, issued March 22, 2004 (S)
August 23, 2004	Consent Order issued, Case No. E-010007 dated August 20, 2004
September 16, 2005	PTC No. P-050301, issued September 16, 2005 (replaced PTC No. 040300 issued March 22, 2004) (A)
October 4, 2005	Tier I Operating Permit No. Tl-050308, issued October 4, 2005 (S)
December 6, 2005	BAF requested closure of the consent order for Case No. E-010007
January 23, 2006	DEQ terminated the consent order for Case No. E-010007
August 26, 2009	P-2009.0042, Natural gas finish dryer (S)
January 20, 2011	P-2009.0043, FEC permit, replaces P-2009.0042 (A)

4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

Application Scope

This permit is the renewal of the facility's currently effective Tier I operating permit.

Application Chronology

May 19, 2012	DEQ received application
July 11, 2012	DEQ determined that the application was complete.
October 26, 2012	DEQ made available the draft permit and statement of basis for peer and regional office review.

November 2, 2012 DEQ made available the draft permit and statement of basis for applicant review.

Month Day – Month Day, Year DEQ provided a public comment period on the proposed action.

Month Day, Year ***{For projects with public hearings}*** DEQ provided a public hearing in CITY.

5. EMISSIONS UNITS, PROCESS DESCRIPTION(S), AND EMISSIONS INVENTORY

This section lists the emissions units, describes the production or manufacturing processes, and provides the emissions inventory for this facility. The information presented was provided by the applicant in its permit application. Also listed in this section are the insignificant activities based on size or production rate.

5.1 Process No. 1 – REGULATED SOURCES

Table 5.1 lists the emissions units and control devices associated with the sources regulated by the Facility Emissions Cap (FEC) PTC.

Table 5.1 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)
Boiler 1	Manufacturer: Murray Model: D-style S/N: 9925 Heat input rating: 57 MMBtu/hr Maximum steam production rate: 45,500 lb/hr Fuels: Natural gas, #2 fuel oil, and #6 fuel oil Date installed: 1982	Wet scrubber: Manufacturer: Carbo-Tech Environmental Group, Inc. Model: 48x48-96HE Type: Venturi Note: Venturi wet scrubber system is used whenever Boilers 1 and/or 2 are combusting fuel oil
Boiler 2	Manufacturer: Johnston Model: 509 Series Heat input rating: 75.4 MMBtu/hr Maximum steam production rate: 62,100 lb/hr Fuels: Natural gas, #2 fuel oil, and #6 fuel oil Date installed: 1994	
Boiler 3	Manufacturer: Springfield Model: 52 Heat input rating: 39 MMBtu/hr Maximum steam production rate: 30,000 lb/hr Date installed: 1975 Fuel: Natural gas and #2 fuel oil	None
Process A		
DHQ	Cooler	None
DHT	Dryer - 7 MMBtu/hr, natural gas-fired	None
DHU	Dryer - 7 MMBtu/hr, natural gas-fired	None
DHZ	Dryer - 6 MMBtu/hr, steam heated and natural gas-fired	None
Process B		
DUQ	Dryer - 7 MMBtu/hr, natural gas-fired	None
DUT	Dryer - 7 MMBtu/hr, natural gas-fired	None
DUV	Dryers – Two, each rated at 6 MMBtu/hr, steam heated and natural gas-fired	None
DQA	Dryer - 7 MMBtu/hr, natural gas-fired	None
DQB	Dryer - 7 MMBtu/hr, natural gas-fired	None
Process C		
CIR	Dryer – Steam heated	None
CXX/CYY	Dryer – 6.05 MMBtu/hr pre-heater, 4.4 MMBtu/hr front dryer, 6.6 MMBtu/hr rear dryer, all natural gas-fired	None
CHX	Dryer – 10.3 MMBtu/hr, steam heated and natural gas-fired, with a 2.9 MMBtu/hr pre-heater, natural gas-fired	None
HEB	Dryer - 6 MMBtu/hr, natural gas-fired	None
CBB	Dryer – 1.5 MMBtu/hr, natural gas-fired	None

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)
CNV	Dryer - 12 MMBtu/hr, natural gas-fired	None
CNW	Dryer - 12 MMBtu/hr, natural gas-fired	None
CTU	Dryer – Steam heated	None
CTZ	Dryer – 5.75 MMBtu/hr, natural gas-fired	Low-NO_X burner
	Space Heaters	None

Fuels combusted include natural gas, #2 fuel oil, and #6 fuel oil.

Process A produces dehydrated potato products via a series of cooling, drying, and materials separation processes. Drying heat is provided by both natural gas combustion and steam produced by the plant boilers.

Process B produces dehydrated potato products via a series of cooling, drying, and materials separation processes. Drying heat is provided by both natural gas combustion and steam produced by the plant boilers.

Process C produces dehydrated food products via a series of cooling, drying, and materials separation processes. Drying heat is provided by both natural gas combustion and steam produced by the plant boilers. Process C also includes materials transport and packaging processes.

5.2 Process No. 2 – FEC REQUIREMENTS

Table 5.2 lists the emissions units and control devices associated with FEC permit.

Table 5.2 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
Boiler 1 Boiler 2 Boiler 3	Scrubber [2] Scrubber[2] None	Boiler Stacks
Process A	None	Multiple Stacks from Process A
Process B	None	Multiple Stacks from Process B
Process C	None (except source CTZ has low-NOx burners)	Multiple Stacks from Process C
Reyco Slice – space heater	None	Fugitive emissions

5.3 Process No. 3 – BOILERS 1, 2, AND 3

Table 5.3 lists the emissions units and control devices associated with Boilers 1, 2, and 3.

Table 5.3 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Boiler 1	<u>Wet Scrubber</u> Manufacturer: Carbo-Tech Environmental Group, Inc. Model: 48x48-96HE Venturi type wet scrubber system used whenever Boilers 1 or 2 are combusting fuel oil Monitoring: SO_2 emissions continuously monitored SO_2 Monitor: Sick Maihak in-situ SO_2 gas analyzer and FLOWSIC volume flow measuring unit
Boiler 2	<u>Wet Scrubber</u> Manufacturer: Carbo-Tech Environmental Group, Inc. Model: 48x48-96HE Venturi type wet scrubber system used whenever Boilers 1 or 2 are combusting fuel oil Monitoring: SO_2 emissions continuously monitored SO_2 Monitor: Sick Maihak in-situ SO_2 as analyzer and FLOWSIC volume flow measuring unit
Boiler 3	None

5.4 Process No. 4 – PROCESS A

Table 5.4 lists the emissions units and control devices associated with Process A.

Table 5.4 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Process A: DHQ-cooler DHT -dryer (7 MMBtu/hr natural gas-fired) DHU -dryer (7 MMBtu/hr natural gas-fired) DHZ -dryer (6 MMBtu/hr steam and natural gas-fired)	None

Process A produces dehydrated potato products. The raw materials put into the process are cooked potatoes and food additives, including sulfites. Process A can operate up to 8,760 hr/yr. There are no alternate operating scenarios.

Emissions units included in Process A include process vents from process equipment. All emissions units associated with this process are potential sources of particulate matter. The drying unit processes can potentially emit SO_2 from the conversion of sulfites. Drying heat is provided by both natural gas combustion and steam produced by the plant's boilers.

5.5 Process No. 5 – PROCESS B

Table 5.5 lists the emissions units and control devices associated with Process B.

Table 5.5 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
DUQ - dryer (7 MMBtu/hr natural gas-fired) DUT - dryer (7 MMBtu/hr natural gas-fired) , DUV - 2 dryers (6 MMBtu/hr each, steam and natural gas-fired) DQA - dryer (7 MMBtu/hr natural gas-fired) DQB - dryer (7 MMBtu/hr natural gas-fired)	None

Process B produces dehydrated potato products. The raw materials put into the process are cooked potatoes and food additives, including sulfites. Process B can operate up to 8,760 hr/yr. There are no alternate operating scenarios.

Emissions units included in Process B include process vents from process equipment. All emissions units associated with this process are potential sources of particulate matter. The drying unit processes can potentially emit SO_2 from the conversion of sulfites. Drying heat is provided by both natural gas combustion and steam produced by the plant's boilers.

5.6 Process No. 6 – PROCESS C

Table 5.6 lists the emissions units and control devices associated with Process C.

Table 5.6 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
ALT/ALQ/ALB: Dryer – steam heated ALX/ALW/ALV/ALY: Dryer – steam heated AGQ/AEV/AEW: Dryer – steam heated CHV/CIR: Dryer- steam heated CXX/CYY: Dryer - 6.05 MMBtu/hr pre-heater, 4.4 MMBtu/hr front dryer, 6.6 MMBtu/hr rear dryer, and a 1.2 MMBtu/hr final heater, natural gas-fired CHX: Pre-dryer – 12.2 MMBtu/hr, natural gas-fired CHY/CHZ: Dryer – 2.5 MMBtu/hr, natural gas-fired CIS: Dryer – steam heated CIT: Dryer – steam heated HEB/HNL: Dryer – steam heated with optional 14 MMBtu/hr pre-heater, natural gas-fired CNV: Dryer - 12 MMBtu/hr, natural gas-fired CNW: Dryer - 12 MMBtu/hr, natural gas-fired CTU: Dryer - steam heated CTZ: Finish dryer - 5.75 MMBtu/hr, natural gas-fired	None Except the burners associated with source CTZ are Low-NO_X burner

Process C produces dehydrated food products. The raw materials put into the process include raw and cooked foods, previously dehydrated foods, and food additives, including sulfites. Process C can operate up to 8,760 hr/yr. There are no alternate operating scenarios.

Emissions units included in Process C include process vents from process equipment. All emissions units associated with this process are potential sources of particulate matter. The process equipment can potentially emit SO_2 from the conversion of sulfites. Drying heat is provided by steam produced by the plant's boilers and natural gas-fired heaters.

5.7 Process No. 7 – PLANT SPACE HEATERS

Table 5.7 lists the emissions units and control devices associated with the plant space heaters.

Table 5.7 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
Reyco Slice: Space heater - 13.0 MMBtu/hr, natural gas-fired	None

The BAF Blackfoot Facility has natural gas-fired space heaters ranging in size from less than 200,000 Btu/hr to 7.5 MMBtu/hr. At the time of permit issuance, total space heater combustion capacity is 59.5 MMBtu/hr. Most of the units provide direct heating; i.e., the combustion air from the unit is discharged directly into the room to provide heating. The Reyco Slice heater is the only space heater with specific permit conditions.

5.8 Process No. 8 – Generator

Table 5.8 lists the emissions units and control devices associated with the generator.

Table 5.8 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit Description	Control Device (if applicable)
International Harvester propane-fired generator	None

The BAF Blackfoot Facility operates an emergency propane-fired generator.

5.9 Insignificant Emissions Units Based on Size or Production Rate

No emissions unit or activity subject to an applicable requirement may qualify as an insignificant emissions unit or activity. As required by IDAPA 58.01.01.317.01.b, insignificant emissions units (IEU's) based on size or production rate must be listed in the permit application. Table 5.4 lists the IEU's identified in the permit application. Also summarized is the regulatory authority or justification for each IEU.

Table 5.9 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION

Emissions Unit / Activity	Regulatory Authority / Justification IDAPA 58.01.01.317.01(b)(i) Citation
Operation, loading, and unloading of storage tanks and storage vessels, with lids or other appropriate closures and less than 260-gallon capacity, heated only to the minimum extent necessary to avoid solidification.	(1)
Operation, loading and unloading of storage tanks not greater than 1,100-gallon capacity with lids, not containing hazardous air pollutants and with maximum vapor pressure of 550 mmHg.	(2)
Operation, loading and unloading of volatile organic compound storage tanks, 10,000-gallon capacity or less, with lids or other appropriate closure and vapor pressure no greater than 80 mmHg at 21°C.	(3)
Operation, loading, unloading, and storage of butane, propane, or liquefied petroleum gas (LPF) in storage tanks or vessels less than 40,000-gallon capacity,	(4)
Combustion sources, less than five MMBtu/hr, use exclusively natural gas, butane, propane, and/or LPG.	(5)
Combustion source, not greater than 0.5 MMBtu/hr, if burning waste wood, wood waste, or waste paper.	(8)
Welding using not more than one /day of welding rod.	(9)
“Parylene” coaters using less than 500 gallons of coating per year.	(11)
Printing and silk-screening, using less than two gal/day of a combination of inks, coatings, adhesives, fountain solutions, thinners, retarders, or non-aqueous cleaning solutions.	(12)
Water cooling towers, not using chromium-based corrosion inhibitors, not using barometric jets or condensers, not greater than 10,000 gal/min, and not in direct contact with gaseous or liquid process streams containing regulated air pollutants.	(13)
Industrial water chlorination, less that 20 million gal/day capacity.	(16)
Surface coating, using less than two gal/day.	(17)
Space heaters and hot water heaters using natural gas, propane or kerosene and generating less than five MMBtu/hr.	(5)
Tanks, vessels, and pumping equipment, with lids or other appropriate closure, for storage or dispensing of aqueous solutions of inorganic salts, bases and acids, excluding solutions with: 99% or greater sulfuric or phosphoric acid; 77% or greater nitric acid; 30% or greater hydrochloric acid; or more than one liquid phase where the top phase is more than 1% VOC.	(19)
Equipment, with lids or other appropriate closure, used exclusively to pump, load, unload, or store high-boiling-point organic material, with initial boiling point not less than 150°C or vapor pressure not more than five mmHg at 21°C.	(20)
Milling and grinding activities (paste forms, if used, are less than 1% volatile organic compounds).	(22)
Rolling, forging, drawing, stamping, shearing, and	(23)

Emissions Unit / Activity	Regulatory Authority / Justification IDAPA 58.01.01.317.01(b)(i) Citation
spinning metals.	
Dip-coating operations using materials with less than 1% VOC.	(24)
Surface coating, aqueous solution or suspension containing less than 1% VOC.	(25)
Cleaning and stripping activities and equipment, using solutions having less than 1% volatile organic compounds by weight (no acid cleaning or stripping on metal substrates).	(26)
Storage and handling of water based lubricants for metal working with organic content less than 10%.	(27)
Natural gas-fired space heating units not listed in §5.7	(30)
Process A – DKW (vent from Process Equipment)	(30)
Process A – DKV (vent from Process Equipment)	(30)
Process B – DXS (vent from Process Equipment)	(30)
Process B – DUO (vent from Process Equipment)	(30)
Process B – DPY (vent from Process Equipment)	(30)
Process B – DPZ (vent from Process Equipment)	(30)
Process B – DUY (vent from Process Equipment)	(30)
Process B – DUZ (vent from Process Equipment)	(30)
Process B – DSO (vent from Process Equipment)	(30)
Process B – DSK (vent from Process Equipment)	(30)
Process B – DUU (vent from Process Equipment)	(30)
Process B – DRY (vent from Process Equipment)	(30)
Process C – ALB (vent from Process Equipment)	(30)
Process C – ALQ (vent from Process Equipment)	(30)
Process C – ALT (vent from Process Equipment)	(30)
Process C – ALY (vent from Process Equipment)	(30)
Process C – ALX (vent from Process Equipment)	(30)
Process C – ALV (vent from Process Equipment)	(30)
Process C – ALW (vent from Process Equipment)	(30)
Process C – AEV (vent from Process Equipment)	(30)
Process C – AEW (vent from Process Equipment)	(30)
Process C – AGQ (vent from Process Equipment)	(30)
Process C – CHV (vent from Process Equipment)	(30)
Process C – IBE (vent from Process Equipment)	(30)
Process C – CHY (vent from Process Equipment)	(30)
Process C – CHZ (vent from Process Equipment)	(30)
Process C – HNL (vent from Process Equipment)	(30)
Process C – CBB (vent from Process Equipment)	(30)
Process C – CTQ (vent from Process Equipment)	(30)
Process C – CTR (vent from Process Equipment)	(30)
Process C – CTS (vent from Process Equipment)	(30)
Process C – CTT (vent from Process Equipment)	(30)
Process C – TCD (vent from Process Equipment)	(30)
Process C – TCO (vent from Process Equipment)	(30)
Process C – TAC (vent from Process Equipment)	(30)
Process C – TAH (vent from Process Equipment)	(30)
Process C – TEM (vent from Process Equipment)	(30)
Process C – TEE (vent from Process Equipment)	(30)
Process C – ENV (vent from Process Equipment)	(30)
Process C – EUW (vent from Process Equipment)	(30)
Process C – ENR (vent from Process Equipment)	(30)
Process C – EDO (vent from Process Equipment)	(30)
Process C – ESX (vent from Process Equipment)	(30)
Process C – EGS (vent from Process Equipment)	(30)
Process C – EGT (vent from Process Equipment)	(30)
Process C – FIF (vent from Process Equipment)	(30)
Process C – CHK (vent from Process Equipment)	(30)
Process C – CHI (vent from Process Equipment)	(30)

5.9 Non-applicable Requirements for Which a Permit Shield is Requested

This section of the permit lists the regulations for which the facility has requested, and DEQ proposes to grant, a permit shield pursuant to IDAPA 58.01.01.325. The findings on which this shield is based are presented below:

Requirement	**Reason Code**
IDAPA Chapter 58.01.01:	
Section 214 Preconstruction Requirements for Major HAP Sources	b
Section 336 Tier I Permits for Portable Sources	b
Section 500 Registration for Portable Equipment	b
Section 563-574 Transportation Conformity	b
Section 580 Classification of PSD Areas	i
Section 582 Conformity for Northern Ada County PM_{10} Maintenance Area	d
Section 610-613 Industrial Flares, Residential Waste Fires, Landfill Site Fires, Orchard Fires	b
Section 626 Visible Emissions from Wigwam Burners	b
Section 776.02 Odors from Rendering Plants	b
Section 750-751 Control of Fluoride Emissions	a
Section 790-999 Rules for Specific Source Categories	b
40CFR	
Part 49 Tribal Clean Air Authority	c
Part 51 Sections 51.1-51.45	i
Part 55 OCS Air Regulations	b
Part 56 Regional Consistency	i
Part 57 Nonferrous Smelter Rules	b
Part 59 VOC Standards for Consumer and Commercial Products	b
Part 60, except subparts A, Dc, and appendixes	b
Part 61, except subpart A, M, and appendices	b
Part 62 Approval and Promulgation of State Plans for Designated Facilities and Pollutants	b
Part 63 National Emission Standards for Hazardous Air Pollutants except ZZZZ	j
Part 64 Compliance Assurance Monitoring (CAM)	g
Part 71 through 80	b
Part 82, except subpart F	b
Parts 85 through 94	b

Reason code definitions:

a this pollutant is not emitted by the facility
b the facility is not currently in this source category
c the facility is not in a special control/nonattainment area
d the facility is not in this county
e the facility does not have this emissions unit
f the facility does not use this fuel type
g the facility does not have any emissions units which are subject to CAM requirements, as determined under 40 CFR 64.2
h this method/procedure is not used by the facility
i this rule applies only to DEQ and regional authorities
j the facility is not subject to any Part 63 NESHAPS other than Subpart ZZZZ

5.10 Emissions Inventory

Table 5.10 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emission is state or federally enforceable.

Listed below Table 5.10 are the references for the emission factors used to estimate the emissions. The documentation provided by the applicant for the emissions inventory and emission factors is provided as Appendix B of this statement of basis.

Table 5.10 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr)

Source Description	PM10 T/yr	NOx T/yr	SO_2 T/yr	CO T/yr	VOC T/yr	Lead T/yr	HAP T/yr	GHG CO_2e T/yr
Boiler 1	18.3	198	145	46	1.3	7.32E-04		28,626
Boiler 2					1.8	1.45E-03		39,454
Boiler 3					0.9	3.28E-04		20,245
DHQ (cooler)	1.38	---	---	---	---	---		---
DHT (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DHU (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DHZ (6 MMBtu NG and steam heated dryer)	7.63	1.3	0.5	6.8	0.1	1.29E-05		3,111
DKV (vent from process equipment)	1.08	---	---	---	---	---		---
DKW (vent from process equipment)	0.03	---	---	---	---	---		---
DXS (vent from process equipment)	0.76	---	---	---	---	---		---
DUO (vent from process equipment)	0.76	---	---	---	---	---		---
DPY (vent from process equipment)	0.76	---	---	---	---	---		---
DPZ (vent from process equipment)	0.76	---	---	---	---	---		---
DUQ (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DUT (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DUV (6 MMBtu each (2) NG and steam heated dryers)	3.58	2.7	1.0	13.7	0.3	2.58E-05		6,221
DQA (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DQB (7 MMBtu NG dryer)	5.06	2.4	0.3	12.3	0.2	1.5E-05		3,629
DUY (vent from process equipment)	0.07	---	---	---	---	7.09E-06		---
DUZ (vent from process equipment)	0.07	---	---	---	---	---		---
DSO (vent from process equipment)	1.06	---	0.1	---	---	---		---
DSK (vent from process equipment)	0.18	---	---	---	---	---		---
DRY (vent from process equipment)	0.09	---	---	---	---	---		---
ALB (vent from process equipment)	0.44	---	0.1	---	---	---		---
ALT (vent from process equipment)	0.03	---	---	---	---	---		---
ALQ (vent from process equipment)	0.28	---	0.1	---	---	---		---
ALY (vent from process equipment)	0.01	---	---	---	---	---		---
ALX (vent from process equipment)	0.05	---	---	---	---	---		---
ALV (vent from process equipment)	0.72	---	0.1	---	---	---		---
ALW (vent from process equipment)	0.46	---	0.1	---	---	---		---
AEV (vent from process equipment)	0.48	0.7	0.1	3.8	0.1	---		1,711
AEW (vent from process equipment)	0.34	---	0.1	---	---	---		---
AGQ (vent from process equipment)	0.01	---	---	---	---	---		---
CIR_RTC (steam heated dryer)	1.72	---	4.1	---	---	---		---
CHV (vent from process equipment)	0.03	---	---	---	---	---		---

CXX/CYY (Dryer – 6.05 MMBtu/hr pre-heater, 4.4 MMBtu/hr front dryer, 6.6 MMBtu/hr rear dryer, all natural gas-fired)	7.51/7.16	2.6/1.5	1.4/1.4	11.9/10.3	0.3/0.2	2.3E-05/ 1.62E-05		5,560/ 3,901
CHX (Dryer – 10.3 MMBtu/hr, steam heated and natural gas-fired, with a 2.9 MMBtu/hr pre-heater, natural gas-fired)	1.49	2.7	0.1	6.2	0.2	1.68E-05		4,054
CHY (vent from process equipment)	0.50	1.6	0.2	3.7	0.1	9.92E-06		2,395
CHZ (vent from process equipment)	0.26	0.8	0.2	1.8	0.1	4.85E-06		1,172
TEE (vent from process equipment)	0.07	---	0.2	---	---	---		---
TEM (vent from process equipment)	0.07	---	0.2	---	---	---		---
HEB (6 MMBtu NG dryer)	6.17	1.3	1.1	2.0	0.3	2.31E-05		5,589
HNL (vent from process equipment)	1.37	0.4	0.2	0.6	0.1	6.91E-06		1,669
CBB (1.5 MMBtu NG dryer)	0.79	0.3	0.4	1.7	0.0	3.22E-06		778
CTQ (vent from process equipment)	0.63	0.9	0.3	4.6	0.1	8.60E-06		2,077
CTR (vent from process equipment)	0.61	1.5	0.3	7.5	0.2	1.41E-05		3,416
CTS (vent from process equipment)	0.19	2.0	0.2	10.0	0.2	1.89E-05		4,553
CTT (vent from process equipment)	0.16	2.2	0.2	11.0	0.2	2.08E-05		5,029
CNV (12 MMBtu NG dryer)	0.58	2.7	0.2	13.7	0.3	2.58E-05		6,221
CNW (12 MMBtu NG dryer)	0.59	2.7	0.2	13.7	0.3	2.58E-05		6,221
CTU (steam heated dryer)	3.96	---	0.5					
CTZ (5.75 MMBtu NG dryer)	1.00	0.5	0.4	0.7	0.3	2.32E-05		5,599
TCD (vent from process equipment)	0.15	0.4	0.5	2.3	0.0	2.68E-06		1,037
TCO (vent from process equipment)	0.15	---	---	---	---	---		---
TAC (vent from process equipment)	0.69	0.3	0.1	1.4	0.0	2.68E-06		648
TAH (vent from process equipment)	0.69	0.3	0.1	1.4	0.0	2.68E-06		648
EUW (vent from process equipment)	0.02	---	---	---	---	---		---
SUF	0.02	---	---	---	---	---		---
DSX	0.04	---	---	---	---	---		---
EGS (vent from process equipment)	0.04	---	---	---	---	---		---
EGT (vent from process equipment)	0.04	---	---	---	---	---		---
FIF (vent from process equipment)	0.13	---	---	---	---	---		---
Total Emissions	106.51	241.4	161.6	248.4	8.3	2.16E-03		181,708

The emission estimates are explained in the emissions inventory appendix spreadsheets.

The PM_{10}, SO_2, CO, and NO_x estimates for the boilers are based on enforceable limits from the 9/16/05 PTC. The VOC estimates were based on AP-42 for the highest emitting fuel.

Emissions estimates for process equipment, including process burners, are based on voluntary source tests done by the facility at various times since 1995. This testing has been done because of the lack of standard emission factors for BAF processes, many of which are proprietary or unique. Development and use of emission factors has been documented in previous permitting actions for the facility through the issuance of Permit to Construct No. 2009.0043, issued January 20, 2011. SO2 emission factors for natural gas combustion in process dryers and space heaters are derived from AP-42 and assume 0.8 grains of sulfur per 100 scf of gas combusted. SO2 emissions associated with conversion of sulfite are based on BAF experience with sulfite conversion in drying processes.

To estimate annual emissions the emission factors are generally used assuming that equipment operates 8760 hours per year at full capacity, with the exception that space heaters are assumed to operate 4380 hours years (50% duty). Plant space heaters are designed and sized for comfort space heating during cold weather periods. During warm weather periods the heaters are not needed and do not operate. In fact were the space heaters to operate when they are not needed for space heating, working conditions inside the plant would become unbearably hot. Accordingly, the assumption that space heaters operate at no more than 50 per cent of firing capacity on an annual basis is a practical and effective limit on operations, as higher operating rates are an operating condition that is contrary to design and that would be detected and corrected.

The only changes in emission factors from those used in Permit to Construct No. 2009.0043 involve the following stacks:

Process	**Stack**	**Pollutants with Revised Emission Factors**
A	DUV	PM-10
C	CHX	PM-10; CO; NOx
C	CHY	PM-10; CO; NOx
C	CHZ	PM-10; CO; NOx
C	TEE	PM-10; CO; NOx
C	TEM	PM-10; CO; NOx
C	CBB	PM-10
C	CTQ	PM-10
C	CTR	PM-10
C	CTS	PM-10
C	CTT	PM-10
C	CNV	PM-10
C	CNW	PM-10
C	CTU	PM-10
C	CTZ	PM-10

The changes in emission factors listed above are based on additional voluntary source testing conducted by BAF in November 2011. This testing program and the basis for changes is documented in BAF's report to DEQ, “Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors”, (Coal Creek Environmental Associates, April 2012), which was submitted to DEQ in accordance with provision 3.4.2 of Permit to Construct No. 2009.0043, issued January 20, 2011.

6. EMISSIONS LIMITS AND MRRR

This section contains the applicable requirements for this major facility. Where applicable, monitoring, recordkeeping and reporting requirements (MRRR) follow the applicable requirement and state how compliance with the applicable requirement is to be demonstrated.

This section is divided into several subsections. The first subsection lists the requirements that apply facility wide. The next subsection lists the emissions units- and emissions activities-specific applicable requirements. The final subsection contains the general provisions that apply to all major facilities subject to Idaho DEQ's Tier I operating permit requirements.

This section contains the following subsections:

- Facility-Wide Conditions;
- Regulated Sources Emissions Limits;
- Facility Emissions Cap Emissions Limits;
- Boilers 1-3 Emissions Limits;
- Process A Emissions Limits;
- Process B Emissions Limits;
- Process C Emissions Limits;
- Plant Space Heaters Emissions Limits;
- Tier I Operating Permit General Provisions.

MRRR

Immediately following each applicable requirement (permit condition) is the periodic monitoring regime upon which compliance with the underlying applicable requirement is demonstrated. A periodic monitoring regime consists of monitoring, recordkeeping and reporting requirements for each applicable requirement. If an applicable requirement does not include sufficient monitoring, recordkeeping and reporting to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit. This is known as gap filling. In addition to the specific MRRR described under each permit condition, generally applicable facility-wide conditions and general provisions may also be required, such as monitoring, recordkeeping, performance testing, reporting, and certification requirements.

The discussion of each permit condition includes the legal and factual basis for the permit condition. If a permit condition was changed due to facility draft or public comments, a description of why and how the condition was changed is provided.

State Enforceability

An applicable requirement that is not required by the federal CAA and has not been approved by EPA as a SIP-approved requirement is identified as a "State-only" requirement and is enforceable only under state law. State-only requirements are not enforceable by the EPA or citizens under the CAA. State-only requirements are identified in the permit within the citation of the legal authority for the permit condition.

Federal Enforceability

Unless identified as "State-only," all applicable requirements, including MRRR, are state and federally enforceable. It should be noted that while a violation of a MRRR is a violation of the permit, it is not necessarily a violation of the underlying applicable requirement (e.g. emissions limit).

To minimize the length of this document, the following permit conditions and MRRR have been paraphrased. Refer to the permit for the complete requirements.

6.1 Facility-Wide Conditions

Permit Condition 2.1 - Fugitive Dust

All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651, 3/30/07]

MRRR (Permit Conditions 2.2 through 2.4)

- Monitor and maintain records of the frequency and the methods used to control fugitive dust emissions;
- Maintain records of all fugitive dust complaints received and the corrective action taken in response to the complaint;
- Conduct facility-wide inspections of all sources of fugitive emissions. If any of the sources of fugitive dust are not being reasonably controlled, corrective action is required.

[IDAPA 58.01.01.322.06, 07, 08, 4/5/2000]

Permit Condition 2.5 - Odors

The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.

[IDAPA 58.01.01.775-776 (State-only), 5/1/94]

MRRR (Permit Condition 2.6)

- Maintain records of all odor complaints received and the corrective action taken in response to the complaint;
- Take appropriate corrective action if the complaint has merit, and log the date and corrective action taken.

[IDAPA 58.01.01.322.06, 07 (State only), 5/1/94]

Permit Condition 2.7 - Visible Emissions

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.

[IDAPA 58.01.01.625, 4/5/00]

MRRR (Permit Condition 2.8 through 2.9)

- Conduct facility-wide inspections of all emissions units subject to the visible emissions standards (or rely on continuous opacity monitoring);
- If visible emissions are observed, take appropriate corrective action and/or perform a Method 9 opacity test;
- Maintain records of the results of each visible emissions inspection.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

Permit Conditions 2.10 through 2.14 - Excess Emissions

The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between the excess emissions facility wide conditions and the regulations of IDAPA 58.01.01.130-136.

MRRR (Permit Conditions 2.11 through 2.14)

Monitoring, recordkeeping and reporting requirements for excess emissions are provided in Sections 131 through 136.

- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events;
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory;
- Notify DEQ of each excess emissions events as soon as possible, including information regarding upset, breakdown, or safety events.
- Submit a report for each excess emissions event to DEQ;
- Maintain records of each excess emissions event.

Permit Condition 2.15 and 2.16 – Fuel-Burning Equipment PM Standards

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuel.

[IDAPA 58.01.01.676-677, 5/1/94]

For fuel-burning equipment in operation prior to October 1, 1979, or with a maximum rated input of 10 MMBtu/hr or less, the permittee shall not discharge to the atmosphere PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas; and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuel.

[IDAPA 58.01.01.677, 5/1/94]

MRR

No specific monitoring is required for these facility-wide conditions. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Conditions 2.17 and 2.18 - Sulfur Content Limits

The permittee shall not sell, distribute, use, or make available for use any of the following:

- Distillate fuel oil containing more than the following percentages of sulfur:
  - ASTM Grade 1 fuel oil, 0.3% by weight.
  - ASTM Grade 2 fuel oil, 0.5% by weight.

[IDAPA 58.01.01.725, 3/29/10]

The permittee shall not sell, distribute, use, or make available for use any residual fuel oil containing more than one and three-fourths percentage (1.75%) sulfur by weight.

[IDAPA 58.01.01.727, 5/1194]

MRRR - (Permit Condition 2.19)

The permittee shall maintain documentation of supplier verification of fuel sulfur content on an as received basis.

[IDAPA 58.01.01.322.06, 5/1/94]

Permit Condition 2.20 - Open Burning

The permittee shall comply with the *Rules for Control of Open Burning*, IDAPA 58.01.01.600-623.

[IDAPA 58.01.01.600-623, 5/08/09]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 2.21 - Asbestos

The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

[40 CFR 61, Subpart M]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 2.22 - Accidental Release Prevention

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR 68.10 (a)]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 2.23 - Recycling and Emissions Reductions

The permittee shall comply with applicable standards for recycling and emissions reduction of refrigerants and their substitutes pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction.

[40 CFR 82, Subpart F]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 2.24 and 2.25 - Monitoring and Recordkeeping

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating 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, 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 58.01.01.322.06, 07, 5/1/94]

During periods when a process or activity is shut down or not operating, monitoring requirements for that process are suspended. In these circumstances, monitoring reports submitted shall note that the process was shut down or not operating, and shall provide, as applicable, the dates of shutdown and start-up.

[IDAPA 58.01.01.322.06, 07, 5/1/94; IDAPA 58.01.01.322.08, 4/5/00]

MRRR

No specific monitoring is required for these facility-wide conditions. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Conditions 2.26 through 2.27 - Performance Testing

If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All 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, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

- The type of method to be used
- Any extenuating or unusual circumstances regarding the proposed test
- The proposed schedule for conducting and reporting the test

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

MRRR (Permit Conditions 2.28 and 2.29)

The permittee shall submit compliance test report(s) to DEQ following required testing.

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

Permit Condition 2.30 - Reports and Certifications

This permit condition establishes generally applicable MRRR for submittal of reports, certifications, and notifications to DEQ and/or EPA as specified.

[IDAPA 58.01.01.322.08, 11, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Permit Condition 2.31 - Incorporation of Federal Requirements by Reference

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.

[IDAPA 58.01.01.107, 4/7/11]

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Regulated Sources Emissions Limits and MRR

There are no emission limits in this section.

Facility Emissions Cap Emissions Limits and MRR

Facility Emissions Cap

Permit Condition 4.4 – Emissions Limits

The PM_{10}, SO_2, NO_X, CO, and VOC emissions from this facility shall not exceed any corresponding facility emissions cap (FEC) limits listed in Table 4.3.

Table 4.3 FEC EMISSIONS LIMITS

Source Description	PM_{10}	SO_2	NO_X	CO	VOC
	T/yr[1]	T/yr[1]	T/yr[1]	T/yr[1]	T/yr[1]
Total Facility Emissions Cap	**128**	**161**	**235**	**235**	**5.1**

[1] Tons per rolling 12-month period.

MRRR - (Permit Condition 4.5)

Criteria Pollutant Facility Emissions Cap Compliance

The permittee shall calculate and record estimated total PM_{10}, SO_2, NO_X, CO, VOC, and Pb emissions for all combustion sources each calendar month, based on fuel consumption, steam production, or heat input rating for natural gas, #2 fuel oil, and #6 fuel oil combustion sources, using the emission factors provided in Appendices A-F of this permit, or other DEQ approved method. Emission factors included in Appendices A-F of this Permit may be updated, with concurrence of DEQ. To update an emission factor, the permittee shall submit to DEQ the proposed revised emission factor and the basis for the revisions. Upon approval by DEQ, the updated emission factor shall replace the corresponding emissions factor in Appendices A-F. Records shall be maintained on site for a period of at least five years and shall be made available to DEQ representatives upon request.

The permittee shall calculate and record estimated total PM_{10} and SO_2 emissions for all production-related sources each calendar month, based on pounds of unit process throughput for production processes and using the emission factors provided in Appendices A-F of this permit, or other DEQ approved method. Emission factors included in Appendices A-F of this Permit may be updated, with concurrence of DEQ. To update an emission factor, the permittee shall submit to DEQ the proposed revised emission factor and the basis for the revisions. Upon approval by DEQ, the updated emission factor shall replace the corresponding emissions factor in Appendices A-F. Records shall be maintained on site for a period of at least five years and shall be made available to DEQ representatives upon request.

The permittee shall calculate rolling 12-month total estimated emissions of PM_{10}, SO_2, NO_X, CO, VOC, and Pb for each calendar month. Emissions totals shall be available within 30 days of the end of a month. The permittee shall total PM_{10}, SO_2, NO_X, CO, VOC, and Pb emissions as calculated for the combustion sources and the production sources to determine compliance with the criteria pollutant FEC. Records shall be maintained on site for a period of at least five years and shall be made available to DEQ representatives upon request.

MRRR - (Permit Condition 4.6)

Demonstration of Preconstruction Compliance with Toxic Standards

The permittee shall maintain documentation of compliance with the requirements of IDAPA 58.01.01.210 for any modifications made to the facility after the issuance date of this permit that may increase toxic air pollutants.

MRRR – (Permit Condition 4.7)

Reporting Requirement

Once per year, the permittee shall report to DEQ the 12-month total facility-wide criteria pollutant emissions recorded under the Criteria Pollutant Emissions Calculation (Permit Condition 4.5.3) used to determine compliance with the Criteria Pollutant FEC (Permit Condition 4.4). The report shall include, but is not limited to, all methods, equations, emissions factors, and sources for emissions factors not previously identified used to determine the 12-month total facility-wide criteria pollutant emissions. Records of the quantity of fuel consumption, steam production, and process throughput used for determining the 12-month total facility-wide criteria pollutant emissions shall be submitted with the annual report. In addition, the permittee shall provide DEQ with the 12-month rolling emissions totals generated under the Criteria Pollutant Emissions Calculation (Permit Condition 4.5.3) for the reporting period.

Any changes in the List of Emissions Units (Permit Condition 4.2) not identified in the previous annual report shall be identified and explained. The report shall be for the period January 1st through December 31st and shall be due on or before January 30th of each calendar year. All reports must be certified in accordance with IDAPA 58.01.01.123. The report shall be sent to DEQ at the following address:

Air Quality Stationary Source Division
Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706
Telephone: (208) 373-0502
Fax: (208) 373-0340

MRRR – (Permit Condition 4.8)

Notice and Recordkeeping of Ambient Concentration Estimates

For facility changes that comply with the terms and conditions establishing the FEC but are not included in the estimate of ambient concentration analysis approved for the permit establishing the FEC, the permittee shall review the estimate of ambient concentration analysis. In the event the facility change would result in a significant contribution (as defined in IDAPA 58.01.01.006) above the design concentration determined by the estimate of ambient concentration analysis approved for the permit establishing the FEC, but does not cause or significantly contribute to a violation of any ambient air quality standard, the permittee shall provide notice to DEQ in accordance with IDAPA 58.01.01.181.01.b. This notice shall also identify new or modified emission factors used to estimate emissions for purposes of this review of the estimate of ambient concentration analysis and for determining compliance with the Criteria Pollutant Facility Emissions Cap Compliance (Permit Condition 4.5).

The permittee shall record and maintain documentation of the review of the ambient concentration analysis on site.

In accordance with IDAPA 58.01.01.181.03, the permittee shall use the most current EPA-approved regulatory guideline model to estimate ambient concentrations where required by the Demonstration of Preconstruction Compliance with Toxic Standards (Permit Condition 4.6.1), except where DEQ approves the permittee's use of an alternative model. The permittee is strongly encouraged to submit a modeling protocol to DEQ for review and approval prior to conducting a modeling analysis using a model that differs from that used in the permit application.

MRRR – (Permit Condition 4.9)

Renewal

In accordance with IDAPA 58.01.01.179.02, the permittee shall submit a complete application for a renewal of the terms and conditions establishing the FEC at least six months before, but no earlier than 18 months before, the expiration date of the FEC permit.

In accordance with IDAPA 58.01.01.177, the permittee's renewal application for the FEC portions of Permit to Construct No. 2009.043 must include the information required under Sections 176 through 181 and Subsections 177.01 through 177.03.

In accordance with IDAPA 58.01.01.177.02.d, regarding Estimates of Ambient Concentrations, for a renewal of terms and conditions establishing a FEC, it is presumed that the previous permitting analysis is satisfactory, unless the Department determines otherwise.

MRRR – (Permit Condition 4.10)

Non-Renewal

If the permittee elects to not renew the terms and conditions establishing the FEC, the permittee shall notify the Department of this decision at least six months before, but not earlier than 18 months before, the expiration date of the FEC provisions of this permit.

If the permittee has made any changes or modifications in accordance with the FEC terms and conditions for which a PTC would have been needed absent the FEC, the permittee’s notice shall identify the changes or modifications and request issuance of one or more PTCs to cover them.

Upon expiration of the FEC terms and conditions, all other provisions of Permit to Construct No. P-2009.0043 shall remain in effect as a Permit to Construct.

MRRR – (Permit Condition 4.11)

List of Emissions Units

A list of boilers, dryers, coolers, and space heaters (except for space heaters with emissions which are “Below Regulatory Concern”) installed at the facility, which are subject to permitting requirements, shall be maintained by the permittee and provided to DEQ personnel upon request. The list shall include:
Identification if equipment was included in the permit application;

- Identification if in service at time of permit issuance;
- Equipment location;
- Installation date, if installed after permit issuance;
- De-installation date if removed after permit issuance; and
- Identification if equipment is subject to NSPS requirements (40 CFR 60).

Boilers 1, 2, and 3 Emissions Limits and MRR

Permit Condition 5.3 – Emissions Limits

PM_{10}, SO_2, NO_X, and CO Emissions - Boilers 1, 2, and 3

Emissions of particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and carbon monoxide (CO) from the exhaust stacks of Boilers 1, 2, and 3 shall not exceed the values listed in Table 5.3.

Table 5.3 BOILER CRITERIA EMISSION LIMITS[A] - HOURLY (LB/HR) AND ANNUAL[B, C] (T/YR)

Source Description	PM_{10}		SO_2		NO_x		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Boiler 1	---	---	---	---	---	---	4.6	---
Boiler 2	---	---	---	---	---	---	6.1	---
Boiler 3	0.30	---	1.9	---	5.4		1.8	---
Combined emissions from Boilers 1 and 2	5.7	---	45.3	---	61.9	---	---	---
Combined emissions from Boilers 1, 2, and 3	---	18.3	---	145	---	198	---	46

A As determined by a pollutant specific U.S. EPA reference method, or DEQ approved alternative, or as determined by DEQ's emission estimation methods used in this permit analysis.

B As determined by multiplying the actual or allowable (if actual is not available) pound per hour emission rate by the allowable hours per year that the process(es) may operate(s), or by actual annual production rates.

C T/yr is tons of emissions per any consecutive l2-month period

MRRR – (Permit Condition 5.26)

Opacity and SO_2 Monitoring - Boilers 1 and 2

Whenever oil is combusted in Boiler 1, opacity from the Boiler 1 stack shall be monitored by complying with the opacity requirements described in the 40 CFR Part 60 (NSPS) requirements for Boiler 2 as described in the operating requirements of this boiler section of this permit, or complying with the alternative opacity monitoring procedure identified in Permit Condition 5.24 and Appendix G.

Whenever oil is combusted in Boiler 1 or Boiler 2, SO_2 emissions from the Boiler(s) shall be monitored by complying with the SO_2 CEMS or fuel sampling requirements as described in the 40 CFR Part 60 (NSPS) requirements for Boiler 2, as described in Section 3 of this permit, for purposes of complying with the Compliance Assurance Monitoring (CAM) exemption requirements under 40 CFR 64.2(b)(1)(vi). Maintaining records of fuel receipts for fuel oil may not be used for this purpose.

MRRR - (Permit Condition 5.27)

PM Performance Test - Boiler 1 and Boiler 2

At least once every five years a PM performance test shall be conducted on the stack of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the PM emission limit in Permit Condition 2.15. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less than once every 5 years. The test shall be conducted in accordance with the procedures outlined in 40 CFR 60, Appendix A, Method 5, or a DEQ-approved alternative. The performance test shall be performed in accordance with IDAPA 58.01.01.157 and the following requirements:

- The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report.
- Visible emissions shall be observed during each performance test run using the methods specified in IDAPA 58.01.01.625.
- The quantity of fuel oil combusted by the boiler during the test shall be recorded in units of gallons per hour.

MRRR – (Permit Condition 5.29)

NO_x Performance Test - Boilers 1 and 2

Within 60 days of achieving the maximum production rate of Boiler 1 and Boiler 2 when firing No.6 fuel oil, but not later than 180 days after issuance of this permit, and at least once every five years thereafter, performance tests shall be conducted to measure NO_x emissions from the stacks of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the pound per hour NO_x emission limits in Permit Condition 5.4. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less than once every five years. The tests shall be conducted in accordance with the procedures outlined in 40 CFR 60, Appendix A, Method 7E, or a DEQ approved alternative. Each performance test shall be performed in accordance with lDAPA 58.01.01.157 and the following requirements:

- The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report.
- Visible emissions shall be observed during each performance test run using the methods specified in IDAPA 58.01.01.625.
- The quantity of fuel oil combusted by the boiler during the test shall be recorded in units of gallons per hour.

MRRR – (Permit Condition 5.31)

Records of Boiler Tuning - Boilers 1, 2, and 3

Records shall be maintained of boiler tuning providing the date the tuning was conducted and a description of adjustments made to the burners to improve combustion efficiency.

MRRR – (Permit Condition 5.32)

Monitoring of Boiler Operating Parameters

The following operating data shall be monitored and recorded for Boilers 1, 2, and 3:

On a monthly basis, record the quantity of natural gas combusted in Boiler 3 in units of MMscf per month and MMscf per consecutive 12-month period. The annual fuel consumption shall be determined by summing the most recent monthly quantity and the monthly quantities over the previous consecutive 11 month period.

On a monthly basis, record the quantity of distillate oil combusted in Boiler 3 in units of gallons per month and gallons per consecutive 12-month period.

On a monthly basis, record the combined quantity of residual oil combusted in Boiler 1 and Boiler 2 in units of gallons per month and gallons per consecutive 12-month period.

On a daily basis, record the date and the combined quantity of residual oil combusted that day in Boiler 1 and Boiler 2.

Each day that residual oil is combusted in Boiler 1 or Boiler 2, record the following: date; total combined pounds of steam produced that day by all three boilers; and the combined average quantity of steam produced by all three boilers in units of pounds per hour, based on a daily average.

MRRR – (Permit Condition 5.33)

Fuel Sulfur Content Receipts - Boilers 1, 2, and 3

For each shipment of fuel oil received, the permittee shall obtain and maintain at the facility fuel receipts from the fuel supplier which demonstrate the oil received complies with the fuel sulfur content limits specified in Permit Condition 2.17 and IDAPA 58.01.01.725-728.

MRRR – (Permit Condition 5.35)

Wet Scrubber Operating Parameters - Boilers 1 and 2

The pressure drop, scrubbing solution pH and scrubbing solution flow rate shall be monitored and recorded once each week when the wet scrubbing system is required to be operated. Monitoring records shall be maintained onsite for a period of five years and made available to DEQ representatives upon request.

MRRR – (Permit Condition 5.38)

Performance Test Reports DEQ - Boilers 1 and 2

Each performance test report, including the required process data, shall be submitted to DEQ within 60 days of the date on which the performance test is conducted.

Permit Condition 5.4 – NO_x Emissions Limits

NO_x Emissions - Boilers 1 and 2

Emissions of NO_x from the exhaust stacks of Boilers l and 2 shall each not exceed 96.64 pounds per 1000 gallons when No. 6 oil is combusted.

MRRR - (Permit Condition 5.29)

NO_x Performance Test - Boilers 1 and 2

Within 60 days of achieving the maximum production rate of Boiler 1 and Boiler 2 when firing No.6 fuel oil, but not later than 180 days after issuance of this permit, and at least once every five years thereafter, performance tests shall be conducted to measure NO_x emissions from the stacks of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the pound per hour NO_x emission limits in Permit Condition 5.4. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less !ban once every five years. The tests shall be conducted in accordance with the procedures outlined in 40 CFR 60, Appendix A, Method 7E, or a DEQ approved alternative. Each performance test shall be performed in accordance with lDAPA 58.01.01.157 and the following requirements:

- The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report.
- Visible emissions shall be observed during each performance test run using the methods specified in IDAPA 58.01.01.625.
- The quantity of fuel oil combusted by the boiler during the test shall be recorded in units of gallons per hour.

MRRR – (Permit Condition 5.31)

Records of Boiler Tuning - Boilers 1, 2, and 3

Records shall be maintained of boiler tuning providing the date the tuning was conducted and a description of adjustments made to the burners to improve combustion efficiency.

MRRR – (Permit Condition 5.32)

Monitoring of Boiler Operating Parameters

The following operating data shall be monitored and recorded for Boilers 1, 2, and 3:

On a monthly basis, record the quantity of natural gas combusted in Boiler 3 in units of MMscf per month and MMscf per consecutive 12-month period. The annual fuel consumption shall be determined by summing the most recent monthly quantity and the monthly quantities over the previous consecutive 11 month period.

On a monthly basis, record the quantity of distillate oil combusted in Boiler 3 in units of gallons per month and gallons per consecutive 12-month period.

On a monthly basis, record the combined quantity of residual oil combusted in Boiler 1 and Boiler 2 in units of gallons per month and gallons per consecutive 12-month period.

On a daily basis, record the date and the combined quantity of residual oil combusted that day in Boiler 1 and Boiler 2.

Each day that residual oil is combusted in Boiler 1 or Boiler 2, record the following: date; total combined pounds of steam produced that day by all three boilers; and the combined average quantity of steam produced by all three boilers in units of pounds per hour, based on a daily average.

MRRR – (Permit Condition 5.38)

Performance Test Reports DEQ - Boilers 1 and 2

Each performance test report, including the required process data, shall be submitted to DEQ within 60 days of the date on which the performance test is conducted.

Permit Condition 5.5 – PM Emissions Limit for Boiler 2

PM Emissions - Boiler 2

No owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 0.030 lb/MMBtu heat input.

MRRR - (Permit Condition 5.21)

General Performance Testing - Boiler 2 - NSPS

Performance testing conducted for Boiler 2 under 40 CFR Part 60 Subpart Dc shall be performed in accordance with 40 CFR 60 Subpart A, including but not limited to the following requirements under 40 CFR 60.8 and 60.11.

Within 60 days after achieving the maximum production rate at which Boiler 2 facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the EPA Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the EPA Administrator a written report of the results of such performance test(s) in accordance with 40 CFR 60.8(a).

For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 except as otherwise provided in 40 CFR 60.11(e)(l).

Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60 Subpart Dc unless the EPA Administrator provides otherwise in accordance with 40 CFR 60.8(b).

Performance tests shall be conducted under such conditions as the EPA Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the EPA Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard in accordance with 40 CFR 60.8(c).

MRRR - (Permit Condition 5.23)

Monitoring. Compliance and Performance Test Methods and Procedures for PM- Boiler 2 - NSPS

In accordance with 40 CFR 60.45c(a), the owner or operator of an affected facility subject to the opacity standards under 40 CFR 60.43c shall conduct an initial performance test as required under 40 CFR 60.8, and shall conduct subsequent performance tests as requested by the EPA Administrator, to determine compliance with the standards using the following procedures and reference methods:

Particulate matter emissions shall be determined using the methods and procedures in 40 CFR 60.45c(a)(1)-(7).

Method 9 (six-minute average of 24 observations) shall be used for determining the opacity of stack emissions in accordance with 40 CFR 60.45c(a)(8).

In accordance with 40 CFR 60.47c(a), the owner or operator of an affected facility combusting residual oil that is subject to the opacity standards under 40 CFR 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

In accordance with 40 CFR 60.47c(b), all COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (40 CFR Part 60 Appendix B). The span value of the opacity COMS shall be between 60 and 80%.

MRRR - (Permit Condition 5.30)

Record Keeping Requirements - Boiler 2 - NSPS

The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day in accordance with 40 CFR 60.48c(g).

All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record in accordance with 40 CFR 60.48c(i).

MRRR - (Permit Condition 5.34)

40 CFR 60 Subpart A General Provisions - Boiler 2 - NSPS

The permittee shall comply with the requirements of 40 CFR 60 Subpart A for Boiler 2 including, but not limited to, notification of commencement of construction within 30 days of commencement and notification of actual date of startup postmarked within 15 days of that date.

MRRR - (Permit Condition 5.35)

Wet Scrubber Operating Parameters - Boilers 1 and 2

The pressure drop, scrubbing solution pH and scrubbing solution flow rate shall be monitored and recorded once each week when the wet scrubbing system is required to be operated. Monitoring records shall be maintained onsite for a period of five years and made available to DEQ representatives upon request.

Permit Condition 5.6 - Sulfur Dioxide Emissions - Boiler 2 - NSPS

In accordance with 40 CFR 60.42c(d), on and after the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8, whichever date comes first, when oil is combusted in Boiler 2 BAF shall not cause to be discharged into the atmosphere from Boiler 2 any gases that contains SO_2 in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, when oil is combusted in Boiler 2 BAF shall not combust oil in Boiler 2 that contains greater than 0.5 weight percent sulfur.

In accordance with 40 CFR 60.42c(g), compliance with the fuel oil sulfur limits and emission limits of this section shall be determined on a 30-day rolling average basis.

In accordance with 40 CFR 60.42c(i), the SO_2 emission limits and fuel oil sulfur limits under this section apply at all times, including periods of startup, shutdown, and malfunction.

In accordance with 40 CFR 60.42c(j), only the heat input supplied to Boiler 2 from the combustion of oil is counted under this section. No credit is provided for the heat input to Boiler 2 from other fuels or for heat derived from exhaust gases from other sources, such as internal combustion engines and kilns.

MRRR - (Permit Condition 5.22)

Compliance and Performance Test Methods and Procedures for SO_2 - Boiler 2 - NSPS

Except as provided in paragraphs 40 CFR 60.44c(g) and (h) and in 60.8(b), performance tests required under 40 CFR 60.8 shall be conducted following the procedures specified in 40 CFR 60.44c(b), (c), (d), and (e), as applicable. Section 60.8(t) does not apply to this section. The 30-day notice required in 40 CFR 60.8(d) applies only to the initial performance test unless otherwise specified by the EPA Administrator in accordance with 40 CFR 60.44c(a).

The initial performance test required under 40 CFR 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 emission limits under 40 CFR 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which Boiler 2 will be operated, but not later than 180 days after the initial startup of the Boiler 2. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions in accordance with 40 CFR 60.44c(b).

After the initial performance test required under paragraph 40 CFR 60.44c(b) and 60.8, compliance with the SO_2 emission limits under 40 CFR 60.42c is based on the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average SO_2 emission rate is calculated to show compliance with the standard in accordance with 40 CFR 60.44c(c).

If only oil is combusted in Boiler 2, the procedures in Method 19 are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B in accordance with 40 CFR 60.44c(d).

In accordance with 40 CFR 60.44c(g), for oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under 40 CFR 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under 40 CFR 60.46c(d)(2).

In accordance with 40 CFR 60.44c(j), the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating E_{ho} under 40 CFR 60.44c(d) or (e), as applicable, whether or not the minimum emissions data requirements under 40 CFR 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating E_{ho} pursuant to 40 CFR 60.44c(d) or (e), as applicable.

MRRR - (Permit Condition 5.23) - Boiler 2 - NSPS

In accordance with 40 CFR 60.46c(a), except as provided in 40 CFR 60.46c(d) and (e), the owner or operator of an affected facility subject to the SO_2 emission limits under 40 CFR 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The percent reduction requirements under 40 CFR 60.42c do not apply and BAF is not required to measure SO_2 concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO_2 control device.

In accordance with 40 CFR 60.46c(b), the one-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under 40 CFR 60.42c. Each one-hour average SO_2 emission rate must be based on at least 30 minutes of operation and include at least two data points representing two 15-minute periods. Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

In accordance with 40 CFR 60.46c(c), the procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (40 CFR Part 60 Appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (40 CFR Part 60 Appendix F).

(3) 40 CFR 60.46c(c)(3) does not apply

(4) The span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125% of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

As an alternative to operating an SO_2 CEMS, fuel sampling may be conducted in accordance with 40 CFR 60.46c(d).

In accordance with 40 CFR 60.46c(f), the owner or operator of an affected facility operating a CEMS pursuant to 40 CFR 60.46c(a), or conducting as-fired fuel sampling pursuant to 40 CFR 60.46c(d)(1), shall obtain emission data for at least 75% of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the EPA Administrator.

MRRR - (Permit Condition 5.30)

Record Keeping Requirements - Boiler 2 - NSPS

The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day in accordance with 40 CFR 60.48c(g).

All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record in accordance with 40 CFR 60.48c(i).

MRRR - (Permit Condition 5.31)

Records of Boiler Tuning - Boilers 1, 2, and 3

Records shall be maintained of boiler tuning providing the date the tuning was conducted and a description of adjustments made to the burners to improve combustion efficiency.

MRRR - (Permit Condition 5.36)

Notifications and Reporting Requirements - Boiler 2 - NSPS

In accordance with 40 CFR 60.48c(a), BAF shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by 40 CFR 60.7. This notification shall include:

(1) The design heat input capacity of Boiler 2 and identification of fuels to be combusted in Boiler 2.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c or 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating Boiler 2 based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions as described in 40 CFR 60 48c(a)(4).

In accordance with 40 CFR 60.48c(b), the owner or operator of each affected facility subject to the SO_2 emission limits of 40 CFR 60.42c, or the opacity limits of 40 CFR 60.43c, shall submit to the EPA Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in 40 CFR 60 Appendix B.

In accordance with 40 CFR 60.48c(c), the owner or operator of each residual oil-fired affected facility subject to the opacity limits under 40 CFR 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.

In accordance with 40 CFR 60.48c(d), the owner or operator of each affected facility subject to the SO_2 emission limits or fuel oil sulfur limits under 40 CFR 60.42c shall submit reports to the EPA Administrator.

In accordance with 40 CFR 60.48c(e), the owner or operator of each affected facility subject to the SO_2 emission limits or fuel oil sulfur limits under 40 CFR 60.42c shall keep records and submit reports as required under 40 CFR 60.48c(d), including the following information, as applicable:

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) 40 CFR 60.48c(e)(3) does not apply

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which oil was not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (40 CFR 60 Appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60 Appendix F, Procedure 1.

In accordance with 40 CFR 60.48c(j), the reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the EPA Administrator and shall be postmarked by the 30th day following the end of the reporting period.

Permit Condition 5.7 - Visible Emissions - Boiler 2 - NSPS

On and after the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8, whichever date comes first,BAF shall not cause to be discharged into the atmosphere from Boiler 2 any gases that exhibit greater than 20% opacity (six-minute average), except for one six-minute period (average) per hour of not more than 27% opacity in accordance with 40 CFR 60.43c(c).

The opacity standard under 40 CFR 60.43c(c) applies at all times, except during periods of startup, shutdown, or malfunction in accordance with 40 CFR 60.43c(d).

MRRR - (Permit Condition 5.23)

Monitoring Compliance and Performance Test Methods and Procedures for PM- Boiler 2 - NSPS

In accordance with 40 CFR 60.45c(a), the owner or operator of an affected facility subject to the opacity standards under 40 CFR 60.43c shall conduct an initial performance test as required under 40 CFR 60.8, and shall conduct subsequent performance tests as requested by the EPA Administrator, to determine compliance with the standards using the following procedures and reference methods:

- Particulate matter emissions shall be determined using the methods and procedures in 40 CFR 60.45c(a)(1)-(7).
- Method 9 (six-minute average of 24 observations) shall be used for determining the opacity of stack emissions in accordance with 40 CFR 60.45c(a)(8).

In accordance with 40 CFR 60.47c(a), the owner or operator of an affected facility combusting residual oil that is subject to the opacity standards under 40 CFR 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

In accordance with 40 CFR 60.47c(b), all COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (40 CFR Part 60 Appendix B). The span value of the opacity COMS shall be between 60 and 80%.

MRRR - (Permit Condition 5.25)

Alternative Opacity and SO_2 Monitoring Procedures - Boiler 2 - NSPS

After receipt and consideration of a written application, the EPA Administrator may approve alternatives to any monitoring procedures or requirements of 40 CFR Part 60 in accordance with 40 CFR 60.13(i). If approved, provisions of the alternate opacity monitoring plan will replace permit provisions requiring a COMS.

MRRR - (Permit Condition 5.26)

Opacity and SO_2 Monitoring - Boilers 1 and 2

Whenever oil is combusted in Boiler 1, opacity from the Boiler 1 stack shall be monitored by complying with the opacity requirements described in the 40 CFR Part 60 (NSPS) requirements for Boiler 2 as described in the operating requirements of this boiler section of this permit, or complying with the alternative opacity monitoring procedure identified in Permit Condition 5.24 and Appendix G.

Whenever oil is combusted in Boiler 1 or Boiler 2, SO_2 emissions from the Boiler(s) shall be monitored by complying with the SO_2 CEMS or fuel sampling requirements as described in the 40 CFR Part 60 (NSPS) requirements for Boiler 2, as described in Section 3 of this permit, for purposes of complying with the Compliance Assurance Monitoring (CAM) exemption requirements under 40 CFR 64.2(b)(1)(vi). Maintaining records of fuel receipts for fuel oil may not be used for this purpose.

Permit Condition 5.8 - SO_2 and Visible Emissions with Merged Exhaust - Boiler 1

When the exhausts from Boiler 1 and 2 are merged ahead of a single scrubber to comply with Permit Condition 5.17, the exhaust from Boiler 1 shall be subject to the same emissions limits set forth for Boiler

2 in Permit Conditions 6.6 and 6.7, and BAF may install applicable continuous monitoring systems on each effluent or the combined effluent from Boilers 1 and 2 in accordance with 40 CFR 60.13(g).

MRRR - (Permit Condition 5.6)

Same as for Permit Condition 5.6.

Permit Condition 5.9 - Nickel Emissions - Boilers 1 and 2

Combined emissions of nickel from the exhaust stacks of Boilers 1 and 2 shall not exceed 240 pounds per any consecutive 12-month period.

MRRR - (Permit Condition 5.30)

Record Keeping Requirements - Boiler 2 - NSPS

The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day in accordance with 40 CFR 60.48c(g).

All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record in accordance with 40 CFR 60.48c(i).

MRRR - (Permit Condition 5.32)

Monitoring of Boiler Operating Parameters

The following operating data shall be monitored and recorded for Boilers 1, 2, and 3:

On a monthly basis, record the quantity of natural gas combusted in Boiler 3 in units of MMscf per month and MMscf per consecutive 12-month period. The annual fuel consumption shall be determined by summing the most recent monthly quantity and the monthly quantities over the previous consecutive 11 month period.

On a monthly basis, record the quantity of distillate oil combusted in Boiler 3 in units of gallons per month and gallons per consecutive 12-month period.

On a monthly basis, record the combined quantity of residual oil combusted in Boiler 1 and Boiler 2 in units of gallons per month and gallons per consecutive 12-month period.

On a daily basis, record the date and the combined quantity of residual oil combusted that day in Boiler 1 and Boiler 2.

Each day that residual oil is combusted in Boiler 1 or Boiler 2, record the following: date; total combined pounds of steam produced that day by all three boilers; and the combined average quantity of steam produced by all three boilers in units of pounds per hour, based on a daily average.

Permit Condition 5.10 - NO_x Emissions - Boilers 1, 2, and 3

The combined emissions of NO_x from Boiler 1, Boiler 2, and Boiler 3 shall not exceed 198 tons per any consecutive 12-month period.

MRRR - (Permit Condition 5.29)

NO_x Performance Test - Boilers 1 and 2

Within 60 days of achieving the maximum production rate of Boiler 1 and Boiler 2 when firing No.6 fuel oil, but not later than 180 days after issuance of this permit, and at least once every five years thereafter, performance tests shall be conducted to measure NO_x emissions from the stacks of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the pound per hour NO_x emission limits in Permit Condition 2.1. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less than once every five years. The tests shall be conducted in accordance with the procedures outlined in 40 CFR 60, Appendix A, Method 7E, or a DEQ approved alternative. Each performance test shall be performed in accordance with lDAPA 58.01.01.157 and the following requirements:

- The boiler shall be operated at the worst case normal production rate during the performance test. A description of how this requirement was met shall be included in the performance test report.
- Visible emissions shall be observed during each performance test run using the methods specified in IDAPA 58.01.01.625.
- The quantity of fuel oil combusted by the boiler during the test shall be recorded in units of gallons per hour.

Permit Condition 5.39 - NSPS General Provisions

This facility is subject to NSPS Subpart Dc, and is therefore required to comply with applicable General Provisions. The general provisions apply to Boilers 1 and 2 when burning fuel oil.

MRRR

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

Process A Emissions Limits and MRR

Permit Condition 6.1 – Process Weight Rate Limit

The permittee shall not discharge to the atmosphere from any source operating prior to October 1, 1979, PM in excess of the amount shown by the following equations, where E is the allowable emission from the entire source in pounds per hour, and PW is the process weight in pounds per hour.

a. If PW is less than 17,000 lb/hr,

   $E = 0.045(PW)^{0.6}$

b. If PW is equal to or greater than 17,000 lb/hr,

   $E = 1.12(PW)^{0.27}$

MRRR - (Permit Condition 6.1.1)

The process weight PM limitation applies to the collection of emissions units/processes identified in Table 6.1. Demonstrating compliance with the visible emissions requirement contained in Permit Condition 6.2 inherently demonstrates compliance with the process weight PM emissions limitations.

MRRR - (Permit Condition 6.2)

To demonstrate compliance with Permit Condition 2.7, the permittee shall conduct a monthly one minute observation of each affected emissions point or source, using EPA Method 22 (in 40 CFR 60, Appendix A). If visible emissions in excess of 10% opacity are observed from any emissions point or source, a six-minute observation, using EPA Method 9, shall be conducted. The visible emissions evaluations shall be performed during daylight hours under normal operating conditions. The results of each evaluation shall be recorded and shall be maintained in accordance with Permit Condition 2.25.

Process B Emissions Limits and MRR

Permit Condition 7.1 – Process Weight Rate Limit

The permittee shall not discharge to the atmosphere from any source operating prior to October 1, 1979, PM in excess of the amount shown by the following equations, where E is the allowable emission from the entire source in pounds per hour, and PW is the process weight in pounds per hour.

a. If PW is less than 17,000 lb/hr,

$E = 0.045(PW)^{0.6}$

b. If PW is equal to or greater than 17,000 lb/hr,

$E = 1.12(PW)^{0.27}$

MRRR - (Permit Condition 7.1.1)

The process weight PM limitation applies to the collection of emissions units/processes identified in Table 6.1. Demonstrating compliance with the visible emissions requirement contained in Permit Condition 7.2 inherently demonstrates compliance with the process weight PM emissions limitations.

MRRR - (Permit Condition 7.2)

To demonstrate compliance with Permit Condition 2.7, the permittee shall conduct a monthly one minute observation of each affected emissions point or source, using EPA Method 22 (in 40 CFR 60, Appendix A). If visible emissions in excess of 10% opacity are observed from any emissions point or source, a six-minute observation, using EPA Method 9, shall be conducted. The visible emissions evaluations shall be performed during daylight hours under normal operating conditions. The results of each evaluation shall be recorded and shall be maintained in accordance with Permit Condition 2.25.

Process C Emissions Limits and MRR

Process C has been permitted by a PTC since the last Tier I operating permit was issued. Some of the permit conditions in the Tier I were updated to match the most recent permit to construct for that process.

Permit Condition 8.3 – Process Weight Rate Limit

<u>Particulate Matter – New Equipment Process Weight Limitations</u>

The permittee shall not discharge to the atmosphere from any source operating on or after October 1, 1979, PM in excess of the amount shown by the following equations, where E is the allowable emission from the entire source in pounds per hour, and PW is the process weight in pounds per hour.

If PW is less than 9,250 lb/hr,

$E = 0.045 (PW)^{0.60}$

If PW is equal to or greater than 9,250 lb/hr,

$E = 1.10 (PW)^{0.25}$

MRRR - (Permit Condition 8.3.1)

The process weight PM limitation applies to the collection of emissions units/processes identified in Table 8.1. Demonstrating compliance with the visible emissions requirement contained in the Visible Emissions Monitoring requirement (Permit Condition 8.8) inherently demonstrates compliance with the process weight PM emissions limitations.

Permit Condition 8.4 - Emissions Limits

The PM_{10}, SO_2, NO_x, CO, and VOC emissions from the stack of finish dryer CTZ shall not exceed any corresponding emissions rate limits listed in the following Table.

Table 8.3 NATURAL GAS-FIRED FINISH DRYER CTZ EMISSIONS LIMITS[1]

Source Description	PM_{10}		SO_2		NO_x		CO		VOC	
	lb/hr	T/yr[2]	lb/hr	T/yr[2]	lb/hr	T/yr[2]	lb/hr	T/yr[2]	lb/hr	T/yr[2]
Finish Dryer CTZ	0.58	1.63	0.12	0.36	0.20	0.88	1.43	6.24	0.06	0.26

1. In absence of any other credible evidence, compliance is assured by complying with this permit's operating, monitoring and record keeping requirements.
2. Tons per consecutive 12-calendar month period.

MRRR - (Permit Condition 8.8)

Visible Emissions Monitoring

To demonstrate compliance with the Particulate Matter – New Equipment Process Weight Limitations (Permit Condition 8.3), the permittee shall conduct a monthly one-minute observation of each affected emissions point, or source, using EPA Method 22 (in 40 CFR 60, Appendix A). If visible emissions in excess of 10% opacity are observed from any emissions point, or source, a six-minute observation, using EPA Method 9, shall be conducted. The visible emissions evaluations shall be performed during daylight hours under normal operating conditions. The results of each evaluation shall be recorded and shall be maintained in accordance with the Recordkeeping General Requirements permit condition.

MRRR - (Permit Condition 8.9)

Dehydrated Food Products Hourly Production Weight Monitoring

To demonstrate compliance with the dehydrated food products hourly production limit the permittee shall monitor and record dehydrated food products production for the CTZ finish dryer daily. Hourly production shall be determined by dividing total daily dehydrated food products production by the actual hours of operation for the day.

MRRR - (Permit Condition 8.10)

Dehydrated Food Products Annual Production Weight Monitoring

To demonstrate compliance with the dehydrated food products annual production limit the permittee shall monitor and record dehydrated food products production for the CTZ finish dryer monthly and annually. Annual throughput shall be determined by summing total monthly dehydrated food products production over each previous consecutive 12-month period.

MRRR - (Permit Condition 8.11)

The permittee shall comply with the recordkeeping requirements of Facility-Wide Permit Condition 2.25.

Plant Space Heaters Emissions Limits and MRR

Permit Condition 9.3 - Emissions Limits

There are no emission limits specifically applicable to the plant space heaters. Emissions from plant space heaters are regulated as part of the facility emissions cap in Permit Section 4.

MRRR - (Permit Condition 9.4)

Process Description

BAF shall determine the total natural gas usage of plant space heaters on a monthly basis. Natural gas combusted in the plant space heaters will be calculated as the difference between total facility natural gas usage less natural gas combusted in the boilers and process dryers. Emissions shall be calculated using the emission factors in the appendices of the permit.

Compliance Schedule

The previous permit has a compliance plan. Those permit conditions are addressed below:

Permit Condition 7.1

DEQ and BAF have identified that portions of source Process C (including, but not limited to, P6 process dryer and P8 process dryer) are not in compliance because permits to construct were not obtained prior to construction or modification. The permittee has the continuing responsibility to submit any supplementary information needed, including information for any other sources, in accordance with IDAPA 58.01.01.315.

Permit Condition 7.2

The Basic American Foods Blackfoot facility shall submit a complete permit application and all additional information requested by DEQ for issuance of a facility-wide permit within 180 days of ssuance of the initial Tier I operating permit. The application shall address the requirements for Tier II operating permits in accordance with IDAPA 58.01.01.400 through 410.

Resolution: Complete. The initial Tier I operating permit was issued December 11, 2002. Basic American Foods submitted a Tier II application on May 28, 2003, and DEQ issued a letter that determined the application complete on August 8, 2003.

Therefore, these permit condions have been removed from the Tier I permit.

Permit Condition 7.3

In addition to the requirements for Tier II operating permits, the facility-wide permit application shall include all ofthe applicable information and address the applicable requirements for PTCs in accordance with IDAPA 58.01.01.200 through IDAPA 58.01.01.228 for the construction and/or modification of sources for which the permittee was required to, but did not obtain, a PTC. DEQ has identified the sources listed in Permit Condition 7.1 as sources that failed to obtain a permit prior to construction or modification.

Resolution: Complete. DEQ determined the application complete on August 8, 2003.

Permit Condition 7.4

The permittee shall submit a supplemental application that addresses the applicable requirements for PTCs within 30 days of receiving written notification from DEQ if it is determined that the facility should have obtained a PTC or a PTC modification for any other sources or sources at the facility through the development of the facility-wide permit.

Resolution: The facility-wide permit has been issued. Therefore, this permit condition is no longer applicable.

Permit Condition 7.5

The application submittal deadlines set forth in the compliance schedule may be extended if the permittee clearly demonstrates that additional time is needed to collect new data for submittal of a complete application. Extension requests, with complete information to justify the request, must be submitted in writing to DEQ no later than the end of the milestone timeline. The deadlines may be extended through written authorization from DEQ.

Resolution: The facility-wide permit has been issued. Therefore, this permit condition is no longer applicable.

Permit Condition 7.6

DEQ will draft a single proposed facility-wide permit for the facility upon receipt of a compete application. The permit will contain all ofthe terms and conditions necessary to comply with the applicable requirements for PTCs in accordance with IDAPA 58.01.01.200 through 223 and the requirements for Tier II operating permits in accordance with IDAPA 58.01.01.400 through 410. The procedures for issuing a PTC under IDAPA 58.01.01.209 shall be followed concurrently with the procedures for issuing a Tier II operating permit under IDAPA 58.01.01.404.

Resolution: The facility-wide permit has been issued. Therefore, this permit condition is no longer applicable.

Permit Condition 7.7

The Basic American Foods Blackfoot facility shall request a modification to their Tier I operating permit within 30 days after the combined facility-wide operating permit and PTC application is determined complete by DEQ. The Tier I operating permit shall be modified to incorporate all applicable requirements ofthe facility-wide permit and shall be issued concurrently with the facility-wide permit in accordance with the procedures for issuing a Tier I permit in IDAPA 58.01.01.360 through 369.

Resolution: Complete. Basic American Foods submitted a request to modify the Tier I operating permit in a letter dated September 24, 2003.

Permit Condition 7.8

Until such time that a modified Tier I operating permit is issued, the Basic American Foods Blackfoot facility shall submit a progress report each calendar quarter to DEQ, stating when each ofthe milestones and compliance with each condition in the compliance schedule were or will be achieved, an explanation of why any dates were not or will not be met, and a detailed description of any preventative or corrective measures undertaken by the permittee.

Resolution: This is the modified Tier I operating permit. Once this is isssued, the permit condition will no longer be applicable. Therefore, it has been taken out of this permit.

Permit Condition 7.9

This schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

Resolution: Because all of the compliance schedule permit conditions have been met, there is no longer a need for this statement. Therefore, this has been removed from the permit.

There are duplicate conditions in the facility wide permit conditions and in the PTC's. Therefore, the duplicates have not been carried into the Tier I from the PTC's. These are the visible emissions limit, part of the sulfur content in fuel limit, and the fuel burning equipment condition.

New Compliance Schedule

This compliance schedule was taken from PTC No. 2009.0043, issued 1/20/2011.

Permit Condtion 11.1 - PM_{10} Compliance

To ensure compliance with applicable requirements in the Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01, the permittee shall implement the compliance requirements presented in the Exhaust Stacks Proposed For Removal and the Exhaust Stacks Proposed For Increased Stack Heights permit conditions. The Exhaust Stacks Proposed For Removal and the Exhaust Stacks Proposed For Increased Stack Heights permit conditions are necessary to ensure that PM_{10} emissions from the facility do not cause or significantly contribute to a violation of the NAAQS. Any changes in the methods proposed or timeframes specified in this compliance schedule must be approved by DEQ prior to implementation. Upon issuance of PTC No. 2009.0043, issued 1/20/2011, the Permittee has three years to comply with the following permit requirements.

Permit Condtion 11.2 - Exhaust Stacks Proposed For Removal

Unless an alternative compliance method has been demonstrated by Permittee and approved by DEQ the Permittee shall remove and render inoperable the following exhaust stacks at this facility:

Table 11.1 EXHAUST STACKS PROPOSED FOR REMOVAL

Exhaust Stack
CHI
CHK
DKV
DRY
DSK
DSO
DUU

Permit Condtion 11.3 - Exhaust Stacks Proposed For Increased Height

Unless an alternative compliance method has been demonstrated by Permittee and approved by DEQ the Permittee shall increase the following exhaust stacks height at this facility to 90 feet or remove the stack from operation:

Table 11.2 EXHAUST STACKS PROPOSED FOR INCREASED HEIGHT

Exhaust Stack
CHX
CXX
DHT
DHU
DHZ
DQA
DQB
DUQ
DUT
DUV

Permit Condition 11.4 - Exhaust Stacks Identification

The exhaust stacks presented in both the Exhaust Stacks Proposed For Removal and the Exhaust Stacks Proposed For Increased Stack Heights permit conditions shall be identified in a manner that will allow a DEQ representative to positively identify each individual stack.

Permit Condition 11.5

<u>Reporting</u>

After the exhaust stacks have been modified or removed and the PM_{10} modeling analyses have been completed, the permittee shall submit a final report to DEQ detailing the modifications made or the removals of the exhaust stacks and the dates that these actions occurred. If the permittee has submitted an alternate compliance demonstration program that has been approved by DEQ, in accordance with the PM_{10} Compliance requirement (Permit Condition 11.1), the permittee's final report shall detail compliance with the provisions of that alternate compliance plan.

The report shall be sent to DEQ at the following address:

Air Quality Stationary Source Division
Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706
Telephone: (208) 373-0502
Fax: (208) 373-0340

General Provisions

Unless expressly stated, there are no MRRR for the general provisions.

General Compliance, Duty to Comply

The permittee must comply with the terms and conditions of the permit.

[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

General Compliance, Need to Halt or Reduce Activity Not a Defense

The permittee cannot use the fact that it would have been necessary to halt or reduce an activity as a defense in an enforcement action.

[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

General Compliance, Duty to Supplement or Correct Application

The permittee must promptly submit such supplementary facts or corrected information upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application. The permittee must also provide information as necessary to address any new requirements that become applicable after the date a complete application has been filed but prior to the release of a draft permit.

[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

Reopening, Additional Requirements, Material Mistakes, Etc.

This term lists the instances when the permit must be reopened and revised, including times when additional requirements become applicable, when the permit contains mistakes, or when revision or revocation is necessary to assure compliance with applicable requirements.

[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

Reopening, Permitting Actions

This term discusses modification, revocation, reopening, and/or reissuance of the permit for cause. If the permittee files a request to modify, revoke, reissue, or terminate the permit, the request does not stay any permit condition, nor does notification of planned changes or anticipated noncompliance.

[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

Information Requests

The permittee must furnish, within a reasonable time to DEQ, any information, including records required by the permit, that is requested in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.

[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Information Requests, Confidential Business Information

Upon request, the permittee must furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Severability

If any provision of the permit is held to be invalid, all unaffected provisions of the permit will remain in effect and enforceable.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213, or complying with IDAPA 58.01.01.220 through 223. The permittee must comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223, 4/2/08; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01. 383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/11/06; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

All permit conditions are federally enforceable unless specified in the permit as a state or local only requirement. State and local only requirements are not required under the CAA and are not enforceable by EPA or by citizens.

[IDAPA 58.01.01.322.15.j, 5/1/94; IDAPA 58.01.01.322.15.k, 3/23/98; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

Inspection and Entry

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

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- 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; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

New Applicable Requirements

The permittee must continue to comply with all applicable requirements and must comply with new requirements on a timely basis.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

Certification

All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

[IDAPA 58.01.01.322.15.o, 5/1/94; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

Renewal

The permittee shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

Permit Shield

Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
  - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
  - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
  - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
  - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and
  - The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

**[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00;
IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99;
IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]**

Compliance Schedule and Progress Reports

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.
- For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.
- For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.
- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

**[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00;
40 CFR 70.6(c)(3) and (4)]**

Periodic Compliance Certification

The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA as specified.

- Compliance certifications for all emissions units shall be submitted annually unless otherwise specified;
- All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.

[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

False Statements

The permittee may not 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]

No Tampering

The permittee may not 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]

Semiannual Monitoring Reports.

In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months as specified.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

Each and every applicable requirement, including MRRR, is subject to prompt deviation reporting. Deviations due to excess emissions must be reported in accordance Sections 130-136. All instances of deviation from Tier I operating permit requirements must be included in the deviation reports. The reports must describe the probable cause of the deviation and any corrective action or preventative measures taken. Deviation reports must be submitted at least every six months unless the permit specifies a different time period as required by IDAPA 58.01.01.322.08.c. Examples of deviations include, but are not limited to, the following:

- Any situation in which an emissions unit fails to meet a permit term or condition
- Emission control device does not meet a required operating condition
- Observations or collected data that demonstrate noncompliance with an emissions standard
- Failure to comply with a permit term that requires a report

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/11/06; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required, Emissions Trading

No permit revision will be required, under any approved, economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in the permit.

[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

Emergency

In accordance with IDAPA 58.01.01.332, an “emergency” as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

7. REGULATORY REVIEW

Attainment Designation (40 CFR 81.313)

The facility is located in Bingham 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.

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

Post project facility-wide emissions from this facility have a potential to emit greater then 100 tons per year for PM_{10}, SO_2, NO_x, and CO as demonstrated in the Emissions Inventories section of this analysis. Therefore, this facility is classified as a major facility as defined in IDAPA 58.01.01.008.10.

PSD Classification (40 CFR 52.21)

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1). The facility does not have facility-wide emissions for any criteria pollutant that exceeds 250 T/yr. In addition, the facility is not undergoing any physical change at a stationary source not otherwise qualifying under 40 CFR 52.21(b)(1) as a major stationary source that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore, the PSD requirements do not apply.

NSPS Applicability (40 CFR 60)

40 CFR 60 Subpart Dc applies to Boiler No. 2 and was addressed in the statement of basis for P-050301, issued September 16, 2005 and in the statement of basis for P-2009.0043, issued January 20, 2011.

Boilers 1 and 3 were constructed before June 9, 1989, so are not subject to Subpart Dc.

NESHAP Applicability (40 CFR 61)

This facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

40 CFR 63 Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The BAF Blackfoot Facility has a 201 HP-rated propane fired gas engine that provides emergency backup power for one of the plant water supply wells. The engine was installed in 1962. It is typically operated approximately once/month for a short time. The engine has a non-resettable hours meter.

In accordance with 40 CFR 63.6595(a)(1), because the facility has an existing stationary SI RICE located at an area source of HAP emissions, the facility must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

In accordance with 40 CFR 63.6595(c), because the facility operates an affected source, the facility must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

In accordance with 40 CFR 63.6603(a), the facility must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to the generator.

In accordance with 40 CFR 63 Subpart ZZZZ Table 2d, no later than October 19, 2013, except during periods of start-up, the facility shall:

a. *Change oil and filter every 1,000 hours of operation or annually, whichever comes first;*

b. *Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;*

c. *Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.*

In accordance with 40 CFR 63.6605(b), at all times, the facility must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the facility to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

40 CFR 63.6625:

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

40 CFR 63.6625:

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

In accordance with 40 CFR 63 Subpart ZZZZ Table 6, the permittee shall demonstrate continuous compliance by:

i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or

ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

40 CFR 63.6640:

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §

63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

The above paragraph is not applicable.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

The compliance report referred to in 40 CFR63.6650 is a requirement of Table 7. This does not apply to emergency engines.

From 40 CFR 63.6650(f): *Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in 40 CFR 63 Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A).*

From 40 CFR 6650(h): *If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose* *specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.*

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

From 40 CFR 63.6655:

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

There are no emission or operating limits specified in Table 6 for the engine. There are work or management practices, but this subpart specifically states, "emisson or operating limitation."

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

Parts (2) and (3) apply, so this recordkeeping requirement applies.

From 40 CFR 63.6655:

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

Part (f)(2) applies.

40 CFR 63 Subpart ZZZZ Table 8 identifies the general provisions that apply to RICE that are subject to 40 CFR Subpart ZZZZ in general. Because this table addresses the general provisions that apply to RICE in general, some parts will apply to the RICE permitted by this permit, and some parts will not apply.

General provisions citation	***Subject of citation***	***Applies to subpart***	***Explanation***
§ 63.1	*General applicability of the General Provisions*	*Yes.*	
§ 63.2	*Definitions*	*Yes*	*Additional terms defined in § 63.6675.*
§ 63.3	*Units and abbreviations*	*Yes.*	
§ 63.4	*Prohibited activities and circumvention*	*Yes.*	
§ 63.5	*Construction and reconstruction*	*Yes.*	
§ 63.6(a)	*Applicability*	*Yes.*	
§ 63.6(b)(1)-(4)	*Compliance dates for new and reconstructed sources*	*Yes.*	
§ 63.6(b)(5)	*Notification*	*Yes.*	
§ 63.6(b)(6)	*[Reserved]*		
§ 63.6(b)(7)	*Compliance dates for new and reconstructed area sources that become major sources*	*Yes.*	
§ 63.6(c)(1)-(2)	*Compliance dates for existing sources*	*Yes.*	
§ 63.6(c)(3)-(4)	*[Reserved]*		
§ 63.6(c)(5)	*Compliance dates for existing area sources that become major sources*	*Yes.*	
§ 63.6(d)	*[Reserved]*		
§ 63.6(e)	*Operation and maintenance*	*No.*	
§ 63.6(f)(1)	*Applicability of standards*	*No.*	
§ 63.6(f)(2)	*Methods for determining compliance*	*Yes.*	
§ 63.6(f)(3)	*Finding of compliance*	*Yes.*	
§ 63.6(g)(1)-(3)	*Use of alternate standard*	*Yes.*	
§ 63.6(h)	*Opacity and visible emission standards*	*No*	*Subpart ZZZZ does not contain opacity or visible emission standards.*
§ 63.6(i)	*Compliance extension procedures and criteria*	*Yes.*	
§ 63.6(j)	*Presidential compliance*	*Yes.*	

	exemption		
§ 63.7(a)(1)-(2)	*Performance test dates*	*Yes*	*Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.*
§ 63.7(a)(3)	*CAA section 114 authority*	*Yes.*	
§ 63.7(b)(1)	*Notification of performance test*	*Yes*	*Except that § 63.7(b)(1) only applies as specified in § 63.6645.*
§ 63.7(b)(2)	*Notification of rescheduling*	*Yes*	*Except that § 63.7(b)(2) only applies as specified in § 63.6645.*
§ 63.7(c)	*Quality assurance/test plan*	*Yes*	*Except that § 63.7(c) only applies as specified in § 63.6645.*
§ 63.7(d)	*Testing facilities*	*Yes.*	
§ 63.7(e)(1)	*Conditions for conducting performance tests*	*No.*	*Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.*
§ 63.7(e)(2)	*Conduct of performance tests and reduction of data*	*Yes*	*Subpart ZZZZ specifies test methods at § 63.6620.*
§ 63.7(e)(3)	*Test run duration*	*Yes.*	
§ 63.7(e)(4)	*Administrator may require other testing under section 114 of the CAA*	*Yes.*	
§ 63.7(f)	*Alternative test method provisions*	*Yes.*	
§ 63.7(g)	*Performance test data analysis, recordkeeping, and reporting*	*Yes.*	
§ 63.7(h)	*Waiver of tests*	*Yes.*	
§ 63.8(a)(1)	*Applicability of monitoring requirements*	*Yes*	*Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.*
§ 63.8(a)(2)	*Performance specifications*	*Yes.*	
§ 63.8(a)(3)	*[Reserved]*		
§ 63.8(a)(4)	*Monitoring for control devices*	*No.*	
§ 63.8(b)(1)	*Monitoring*	*Yes.*	
§ 63.8(b)(2)-(3)	*Multiple effluents and multiple monitoring systems*	*Yes.*	
§ 63.8(c)(1)	*Monitoring system operation and maintenance*	*Yes.*	
§ 63.8(c)(1)(i)	*Routine and predictable SSM*	*No.*	
§ 63.8(c)(1)(ii)	*SSM not in Startup Shutdown Malfunction Plan*	*Yes.*	
§ 63.8(c)(1)(iii)	*Compliance with operation and maintenance requirements*	*No.*	
§ 63.8(c)(2)-(3)	*Monitoring system installation*	*Yes.*	
§ 63.8(c)(4)	*Continuous monitoring system (CMS) requirements*	*Yes*	*Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).*
§ 63.8(c)(5)	*COMS minimum procedures*	*No*	*Subpart ZZZZ does not require COMS.*
§ 63.8(c)(6)-(8)	*CMS requirements*	*Yes*	*Except that subpart ZZZZ does not require COMS.*
§ 63.8(d)	*CMS quality control*	*Yes.*	
§ 63.8(e)	*CMS performance evaluation*	*Yes*	*Except for § 63.8(e)(5)(ii), which applies to COMS.*
		Except that § 63.8(e) only applies as specified in § 63.6645.	
§ 63.8(f)(1)-(5)	*Alternative monitoring method*	*Yes*	*Except that § 63.8(f)(4) only applies as specified in § 63.6645.*
§ 63.8(f)(6)	*Alternative to relative accuracy*	*Yes*	*Except that § 63.8(f)(6) only applies as*

	test		*specified in § 63.6645.*
§ 63.8(g)	*Data reduction*	*Yes*	*Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.*
§ 63.9(a)	*Applicability and State delegation of notification requirements*	*Yes.*	
§ 63.9(b)(1)-(5)	*Initial notifications*	*Yes*	*Except that § 63.9(b)(3) is reserved.*
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	*Request for compliance extension*	*Yes*	*Except that § 63.9(c) only applies as specified in § 63.6645.*
§ 63.9(d)	*Notification of special compliance requirements for new sources*	*Yes*	*Except that § 63.9(d) only applies as specified in § 63.6645.*
§ 63.9(e)	*Notification of performance test*	*Yes*	*Except that § 63.9(e) only applies as specified in § 63.6645.*
§ 63.9(f)	*Notification of visible emission (VE)/opacity test*	*No*	*Subpart ZZZZ does not contain opacity or VE standards.*
§ 63.9(g)(1)	*Notification of performance evaluation*	*Yes*	*Except that § 63.9(g) only applies as specified in § 63.6645.*
§ 63.9(g)(2)	*Notification of use of COMS data*	*No*	*Subpart ZZZZ does not contain opacity or VE standards.*
§ 63.9(g)(3)	*Notification that criterion for alternative to RATA is exceeded*	*Yes*	*If alternative is in use.*
		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)-(6)	*Notification of compliance status*	*Yes*	*Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.*
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	*Adjustment of submittal deadlines*	*Yes.*	
§ 63.9(j)	*Change in previous information*	*Yes.*	
§ 63.10(a)	*Administrative provisions for recordkeeping/reporting*	*Yes.*	
§ 63.10(b)(1)	*Record retention*	*Yes.*	*Except that the most recent 2 years of data do not have to be retained on site.*
§ 63.10(b)(2)(i)-(v)	*Records related to SSM*	*No.*	
§ 63.10(b)(2)(vi)-(xi)	*Records*	*Yes.*	
§ 63.10(b)(2)(xii)	*Record when under waiver*	*Yes.*	
§ 63.10(b)(2)(xiii)	*Records when using alternative to RATA*	*Yes*	*For CO standard if using RATA alternative.*
§ 63.10(b)(2)(xiv)	*Records of supporting documentation*	*Yes.*	
§ 63.10(b)(3)	*Records of applicability determination*	*Yes.*	
§ 63.10(c)	*Additional records for sources using CEMS*	*Yes*	*Except that § 63.10(c)(2)-(4) and (9) are reserved.*
§ 63.10(d)(1)	*General reporting requirements*	*Yes.*	
§ 63.10(d)(2)	*Report of performance test results*	*Yes.*	
§ 63.10(d)(3)	*Reporting opacity or VE observations*	*No*	*Subpart ZZZZ does not contain opacity or VE standards.*

§ 63.10(d)(4)	*Progress reports*	*Yes.*	
§ 63.10(d)(5)	*Startup, shutdown, and malfunction reports*	*No.*	
§ 63.10(e)(1) and (2)(i)	*Additional CMS Reports*	*Yes.*	
§ 63.10(e)(2)(ii)	*COMS-related report*	*No*	*Subpart ZZZZ does not require COMS.*
§ 63.10(e)(3)	*Excess emission and parameter exceedances reports*	*Yes.*	*Except that § 63.10(e)(3)(i) (C) is reserved.*
§ 63.10(e)(4)	*Reporting COMS data*	*No*	*Subpart ZZZZ does not require COMS.*
§ 63.10(f)	*Waiver for recordkeeping/reporting*	*Yes.*	
§ 63.11	*Flares*	*No.*	
§ 63.12	*State authority and delegations*	*Yes.*	
§ 63.13	*Addresses*	*Yes.*	
§ 63.14	*Incorporation by reference*	*Yes.*	
§ 63.15	*Availability of information*	*Yes.*	

40 CFR 63 Subpart JJJJJJ................. National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

§ 63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195.

The facility has three applicable boilers, so the facility is subject to 40 CFR 63 Subpart JJJJJJ.

§ 63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory (coal, biomass, oil), as listed in § 63.11200 and defined in § 63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

Each of the three boilers was installed prior to June 4, 2010, so are existing boilers.

The boilers burn oil as well as natural gas. Next step is to look up definition of the oil subcategory.

Definition in accordance with 40 CFR 63.11237:

<u>Oil subcategory</u> *includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.*

BAF has not burned any oil in any of its boilers since 2009.

From 40 CFR 63.11195: *The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.*

…

(e) A gas-fired boiler as defined in this subpart.

From 40 CFR 63.11237:

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

The boilers currently meet the definition of gas-fired boilers and are not currently subject to Subpart JJJJJJ. If BAF decides in the future to burn non-gas fuel, the following rule applies:

40 CFR 63.11210(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJJ or the boiler becoming subject to subpart JJJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

Applicable requirements can be addressed at such future time as BAF elects to switch fuels and become subject to the rule.

Because the current permits allow the use of oil, a permit condition was written to require compliance with 40 CFR63 Subpart JJJJJJ if oil is used in the boiler(s).

CAM Applicability (40 CFR 64)

CAM does not apply as addressed in the statement of basis for T1-060315, dated November 5, 2007.

8. PUBLIC COMMENT

As required by IDAPA 58.01.01.364, a public comment period was made available to the public from **DATE to DATE**. During this time, comments **WERE / WERE NOT** submitted in response to DEQ's proposed action. ***{If comments were received, include the following text.}*** 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.

IF A PUBLIC HEARING IS PROVIDED:

In addition to the public comment period, DEQ also provided a public hearing for persons interested to appear and submit written or oral comments. The public hearing was provided on **DATE in CITY**. DEQ's response to the comments submitted during the public hearing is also included in the response to public comments document.

9. EPA REVIEW OF PROPOSED PERMIT

As required by IDAPA 58.01.01.366, DEQ provided the proposed permit to EPA Region 10 for its review and comment on **DATE** via e-mail. On **DATE**, EPA Region 10 responded to DEQ via e-mail indicating **EPA RESPONSE**.

Appendix A - Emissions Inventory

Table C-1
Emissions Summary

Production Process	Stack Identification	Estimated Annual Emissions, tons									
		CO	NOX	SO2	PM	PM-10	PM-2.5	VOC	Lead	GHG	CO2e
Boilers	Boiler 1	-	-	-	9.56	-	-	1.3	-	28,453	28,626
Boilers	Boiler 2	-	-	-	11.80	-	-	1.8	1.45E-03	39,215	39,454
Boilers	Boiler 3	-	-	-	1.71	-	-	0.9	3.28E-04	20,122	20,245
Boilers	Boilers 1 and 2	-	-	-	-	-	-	-	-	-	-
Boilers	Boilers 1, 2, and 3	46.0	198.0	145.0	-	18.3	-	-	-	-	-
A	DHQ	-	-	-	1.44	1.38	1.3	-	-	-	-
A	DHT	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
A	DHU	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
A	DHZ	6.8	1.3	0.5	10.67	7.63	5.6	0.1	1.29E-05	3,092	3,111
A	DKV	-	-	-	1.85	1.08	0.5	-	-	-	-
A	DKW	-	-	-	0.06	0.03	0.0	-	-	-	-
B	DXS	-	-	-	0.83	0.76	0.7	-	-	-	-
B	DUO	-	-	-	0.83	0.76	0.7	-	-	-	-
B	DPY	-	-	-	0.83	0.76	0.7	-	-	-	-
B	DPZ	-	-	-	0.83	0.76	0.7	-	-	-	-
B	DUQ	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
B	DUT	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
B	DUV	13.7	2.7	1.0	5.32	3.58	3.0	0.3	2.58E-05	6,184	6,221
B	DQA	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
B	DQB	12.3	2.4	0.3	6.48	5.06	4.0	0.2	1.50E-05	3,607	3,629
B	DUY	-	-	-	0.11	0.07	0.0	-	-	-	-
B	DUZ	-	-	-	0.11	0.07	0.0	-	-	-	-
B	DSO	-	-	0.1	1.22	1.06	1.0	-	-	-	-
B	DSK	-	-	-	0.34	0.18	0.1	-	-	-	-
B	DRY	-	-	-	0.18	0.09	0.0	-	-	-	-
C	ALB	-	-	0.1	0.68	0.44	0.3	-	-	-	-
C	ALT	-	-	-	0.06	0.03	0.0	-	-	-	-
C	ALQ	-	-	0.1	0.36	0.28	0.2	-	-	-	-
C	ALY	-	-	-	0.02	0.01	0.0	-	-	-	-
C	ALX	-	-	-	0.11	0.05	0.0	-	-	-	-
C	ALV	-	-	0.1	1.12	0.72	0.5	-	-	-	-
C	ALW	-	-	0.1	0.59	0.46	0.4	-	-	-	-
C	AEV	3.8	0.7	0.1	0.74	0.48	0.4	0.1	7.09E-06	1,700	1,711
C	AEW	-	-	0.1	0.46	0.34	0.3	-	-	-	-
C	AGQ	-	-	-	0.03	0.01	0.0	-	-	-	-
C	CIR_RTC	-	-	4.1	1.72	1.72	1.7	-	-	-	-
C	CHV	-	-	-	0.11	0.03	0.0	-	-	-	-
C	CXX	11.9	2.6	1.4	9.86	7.51	5.9	0.3	2.30E-05	5,527	5,560
C	CYY	10.3	1.5	1.4	8.32	7.16	6.3	0.2	1.62E-05	3,878	3,901
C	CHX	6.2	2.7	0.1	1.99	1.49	1.3	0.2	1.68E-05	4,030	4,054
C	CHY	3.7	1.6	0.2	0.69	0.50	0.4	0.1	9.92E-06	2,381	2,395
C	CHZ	1.8	0.8	0.2	0.50	0.26	0.2	0.1	4.85E-06	1,165	1,172
C	TEE	-	-	0.2	0.17	0.07	0.0	-	-	-	-
C	TEM	-	-	0.2	0.17	0.07	0.0	-	-	-	-
C	HEB	2.0	1.3	1.1	7.12	6.17	5.9	0.3	2.31E-05	5,555	5,589
C	HNL	0.6	0.4	0.2	1.70	1.37	1.3	0.1	6.91E-06	1,659	1,669
C	CBB	1.7	0.3	0.4	0.95	0.79	0.7	0.0	3.22E-06	773	778
C	CTQ	4.6	0.9	0.3	0.90	0.63	0.5	0.1	8.60E-06	2,065	2,077
C	CTR	7.5	1.5	0.3	0.94	0.61	0.5	0.2	1.41E-05	3,395	3,416
C	CTS	10.0	2.0	0.2	0.35	0.19	0.1	0.2	1.89E-05	4,525	4,553
C	CTT	11.0	2.2	0.2	0.38	0.16	0.1	0.2	2.08E-05	4,998	5,029
C	CNV	13.7	2.7	0.2	0.59	0.58	0.6	0.3	2.58E-05	6,184	6,221
C	CNW	13.7	2.7	0.2	0.61	0.59	0.6	0.3	2.58E-05	6,184	6,221
C	CTU	-	-	0.5	4.49	3.96	3.8	-	-	-	-
C	CTZ	0.7	0.5	0.4	1.49	1.00	0.9	0.3	2.32E-05	5,565	5,599
C	TCD	2.3	0.4	0.5	0.15	0.15	0.1	0.0	4.29E-06	1,031	1,037
C	TCO	-	-	-	0.15	0.15	0.1	-	-	-	-
C	TAC	1.4	0.3	0.1	0.80	0.69	0.7	0.0	2.68E-06	644	648
C	TAH	1.4	0.3	0.1	0.80	0.69	0.7	0.0	2.68E-06	644	648
C	EUW	-	-	-	0.02	0.02	0.0	-	-	-	-
C	SUF	-	-	-	0.02	0.02	0.0	-	-	-	-
C	DSX	-	-	-	0.07	0.04	0.0	-	-	-	-
C	EGS	-	-	-	0.08	0.04	0.0	-	-	-	-
C	EGT	-	-	-	0.08	0.04	0.0	-	-	-	-
C	FIF	-	-	-	0.13	0.13	0.1	-	-	-	-
Total - Point Sources		**248.4**	**241.4**	**161.6**	**136.15**	**106.51**	**73.6**	**8.3**	**2.16E-03**	**180,609**	**181,708**

Table C-2
Carbon Monoxide Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
Boilers	Boiler 1	*Enforceable limit from PTC P-050301 (10/05)*		
Boilers	Boiler 2			
Boilers	Boiler 3			
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	0.400	lbs CO/ MM Btu	Similarity to stack DUT.
A	DHU	0.400	lbs CO/ MM Btu	Similarity to stack DUT.
A	DHZ	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
B	DUQ	0.400	lbs CO/ MM Btu	Similarity to stack DUT.
B	DUT	0.400	lbs CO/ MM Btu	Average of direct measurements of stack CO emissions in Dec 97 and Oct 2000.
B	DQA	0.400	lbs CO/ MM Btu	Similarity to stack DUT.
B	DQB	0.400	lbs CO/ MM Btu	Similarity to stack DUT.
B	DUV	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	AEV	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CXX	0.254	lbs CO/ MM Btu	Based on stack emission measurements (Oct 2000).
C	CYY	0.313	lbs CO/ MM Btu	Based on stack emission measurements (Oct 2000).
C	CHX	0.182	lbs CO/ MM Btu	Based on results of stack emission tests conducted in November 2011.
C	CHY	0.182	lbs CO/ MM Btu	Based on results of stack emission tests conducted in November 2011.
C	CHZ	0.182	lbs CO/ MM Btu	Based on results of stack emission tests conducted in November 2011.
C	HEB	0.043	lbs CO/ MM Btu	Based on stack emission measurements (Oct 2000).
C	HNL	0.043	lbs CO/ MM Btu	Based on stack emission measurements (Oct 2000).
C	CBB	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CTQ	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CTR	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CTS	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CTT	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CNV	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CNW	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	CTZ	0.014	lbs CO/ MM Btu	Based on burner manufacturer specification of 20 ppmv CO at 3% 02
C	TCD	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	TAC	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
C	TAH	0.260	lbs CO/ MM Btu	General CO emission factor developed from emission measurements of various BAF process burners.
Plant	Heaters	0.082	lb CO/MMBTU	Based on AP-42, Table 1.4-1 (2/98), for uncontrolled combustion in boiler < 100 MMBTU/hr, and assuming 1020 BTU/scf. On an annual basis, firing assumed to occur at a maximum of 50% of burner capacity.

Table C-3
Estimated Carbon Monoxide Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	*Enforceable limit from PTC P-050301 (10/05)*				
Boilers	Boiler 2					
Boilers	Boiler 3					
Boilers	Boilers 1 and 2					
Boilers	Boilers 1, 2, and 3					46.0
A	DHT	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
A	DHU	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
A	DHZ	0.26	lbs CO/ MM Btu	52,560	MMBtu	6.8
B	DUQ	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
B	DUT	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
B	DQA	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
B	DQB	0.40	lbs CO/ MM Btu	61,320	MMBtu	12.3
B	DUV	0.26	lbs CO/ MM Btu	105,120	MMBtu	13.7
C	AEV	0.26	lbs CO/ MM Btu	28,908	MMBtu	3.8
C	CXX	0.25	lbs CO/ MM Btu	93,951	MMBtu	11.9
C	CYY	0.31	lbs CO/ MM Btu	65,919	MMBtu	10.3
C	CHX	0.18	lbs CO/ MM Btu	68,503	MMBtu	6.2
C	CHY	0.18	lbs CO/ MM Btu	40,471	MMBtu	3.7
C	CHZ	0.18	lbs CO/ MM Btu	19,798	MMBtu	1.8
C	HEB	0.04	lbs CO/ MM Btu	94,433	MMBtu	2.0
C	HNL	0.04	lbs CO/ MM Btu	28,207	MMBtu	0.6
C	CBB	0.26	lbs CO/ MM Btu	13,140	MMBtu	1.7
C	CTQ	0.26	lbs CO/ MM Btu	35,097	MMBtu	4.6
C	CTR	0.26	lbs CO/ MM Btu	57,715	MMBtu	7.5
C	CTS	0.26	lbs CO/ MM Btu	76,931	MMBtu	10.0
C	CTT	0.26	lbs CO/ MM Btu	84,971	MMBtu	11.0
C	CNV	0.26	lbs CO/ MM Btu	105,120	MMBtu	13.7
C	CNW	0.26	lbs CO/ MM Btu	105,120	MMBtu	13.7
C	CTZ	0.01	lbs CO/ MM Btu	94,608	MMBtu	0.7
C	TCD	0.26	lbs CO/ MM Btu	17,520	MMBtu	2.3
C	TAC	0.26	lbs CO/ MM Btu	10,950	MMBtu	1.4
C	TAH	0.26	lbs CO/ MM Btu	10,950	MMBtu	1.4

Table C-3
Estimated Carbon Monoxide Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Plant	Heaters	0.08	lb CO/MMBTU	339,781	MMBtu	14.0

Table C-4
Estimated Nitrogen Oxides Emissions

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
Boilers	Boiler 1	*Enforceable limit from PTC P-050301 (10/05)*		
Boilers	Boiler 2			
Boilers	Boiler 3			
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	0.077	lbs NOx/MM Btu	Similarity to stack DUT.
A	DHU	0.077	lbs NOx/MM Btu	Similarity to stack DUT.
A	DHZ	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
B	DUQ	0.077	lbs NOx/MM Btu	Similarity to stack DUT.
B	DUT	0.077	lbs NOx/MM Btu	Average of direct measurements of stack NOx emissions in Dec 97 and Oct 2000.
B	DQA	0.077	lbs NOx/MM Btu	Similarity to stack DUT.
B	DQB	0.077	lbs NOx/MM Btu	Similarity to stack DUT.
B	DUV	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	AEV	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CXX	0.054	lbs NOx/MM Btu	Based on stack emission measurements (Oct 2000).
C	CYY	0.047	lbs NOx/MM Btu	Based on stack emission measurements (Oct 2000).
C	CHX	0.078	lbs NOx/MM Btu	Based on results of stack emission tests conducted in November 2011.
C	CHY	0.078	lbs NOx/MM Btu	Based on results of stack emission tests conducted in November 2011.
C	CHZ	0.078	lbs NOx/MM Btu	Based on results of stack emission tests conducted in November 2011.
C	HEB	0.027	lbs NOx/MM Btu	Based on stack emission measurements (Oct 2000).
C	HNL	0.027	lbs NOx/MM Btu	Based on stack emission measurements (Oct 2000).
C	CBB	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CTQ	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CTR	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CTS	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CTT	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CNV	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CNW	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	CTZ	0.012	lbs NOx/MM Btu	Based on burner manufacturer specification of 10ppmv NOX at 3% 02
C	TCD	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	TAC	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
C	TAH	0.051	lbs NOx/MM Btu	General NOx emission factor developed from emission measurements of various BAF process burners.
Plant	Heaters	0.098	lb NOx/MMBTU	Based on AP-42, Table 1.4-1 (2/98), for uncontrolled combustion in boiler < 100 MMBTU/hr, and assuming 1020 BTU/scf. On an annual basis, firing assumed to occur at a maximum of 50% of burner capacity.

Table C-5
Estimated Nitrogen Oxides Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	*Enforceable limit from PTC P-050301 (10/05)*				
Boilers	Boiler 2					
Boilers	Boiler 3					
Boilers	Boilers 1 and 2					
Boilers	Boilers 1, 2, and 3					198.0
A	DHT	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
A	DHU	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
A	DHZ	0.05	lbs NOx/MM Btu	52,560	MMBtu	1.3
B	DUQ	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
B	DUT	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
B	DQA	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
B	DQB	0.08	lbs NOx/MM Btu	61,320	MMBtu	2.4
B	DUV	0.05	lbs NOx/MM Btu	105,120	MMBtu	2.7
C	AEV	0.05	lbs NOx/MM Btu	28,908	MMBtu	0.7
C	CXX	0.05	lbs NOx/MM Btu	93,951	MMBtu	2.6
C	CYY	0.05	lbs NOx/MM Btu	65,919	MMBtu	1.5
C	CHX	0.08	lbs NOx/MM Btu	68,503	MMBtu	2.7
C	CHY	0.08	lbs NOx/MM Btu	40,471	MMBtu	1.6
C	CHZ	0.08	lbs NOx/MM Btu	19,798	MMBtu	0.8
C	HEB	0.03	lbs NOx/MM Btu	94,433	MMBtu	1.3
C	HNL	0.03	lbs NOx/MM Btu	28,207	MMBtu	0.4
C	CBB	0.05	lbs NOx/MM Btu	13,140	MMBtu	0.3
C	CTQ	0.05	lbs NOx/MM Btu	35,097	MMBtu	0.9
C	CTR	0.05	lbs NOx/MM Btu	57,715	MMBtu	1.5
C	CTS	0.05	lbs NOx/MM Btu	76,931	MMBtu	2.0
C	CNV	0.05	lbs NOx/MM Btu	105,120	MMBtu	2.7
C	CNW	0.05	lbs NOx/MM Btu	105,120	MMBtu	2.7
C	CTZ	0.01	lbs NOx/MM Btu	94,608	MMBtu	0.5
C	CTT	0.05	lbs NOx/MM Btu	84,971	MMBtu	2.2
C	TCD	0.05	lbs NOx/MM Btu	17,520	MMBtu	0.4
C	TAC	0.05	lbs NOx/MM Btu	10,950	MMBtu	0.3
C	TAH	0.05	lbs NOx/MM Btu	10,950	MMBtu	0.3
Plant	Heaters	0.10	lb NOx/MMBTU	339,781	MMBtu	16.7

Table C-6
Sulfur Dioxide Emission Factors

Production Process	Stack Identification Code	Process Related Sulfur Dioxide Emissions					
		Emission Factor	Emission Factor Units	Basis for Emission Factor	Annual Emissions		Basis for Combustion Emission Factor
Boilers	Boiler 1	-	NA	NA	*Enforceable limit from PTC P-050301 (10/05)*		
Boilers	Boiler 2	-	NA	NA			
Boilers	Boiler 3	-	NA	NA			
Boilers	Boilers 1 and 2	-	NA	NA			
Boilers	Boilers 1, 2, and 3	-	NA	NA			
A	DHT	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
A	DHU	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
A	DHZ	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DUQ	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DUT	0.005	lbs SO2/000 lbs unit process throughput	Average of direct measurements of stack SO2 emissions in Dec 97 and Oct 2000.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DQA	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DQB	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DUV	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
B	DSO	0.005	lbs SO2/000 lbs unit process throughput	Assumed to be the same as stack DUT.	-	-	
C	ALB	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks ALB and ALQ	-	-	
C	ALQ	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks ALB and ALQ	-	-	
C	ALV	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks ALV and ALW	-	-	

Table C-6
Sulfur Dioxide Emission Factors

Production Process	Stack Identification Code	Process Related Sulfur Dioxide Emissions					
		Emission Factor	Emission Factor Units	Basis for Emission Factor	Annual Emissions		Basis for Combustion Emission Factor
C	ALW	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks ALV and ALW	-	-	
C	AEV	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks AEV and AEW	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	AEW	0.011	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated equally between stacks AEV and AEW	-	-	
C	CIR_RTC	0.11	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process.	-	-	
C	CXX	0.058	lbs SO2/000 lbs product	Direct measurement.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CYY	0.061	lbs SO2/000 lbs product	Direct measurement.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CHX	0.000	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CHY	0.019	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CHZ	0.026	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	TEE	0.029	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	-	-	
C	TEM	0.031	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	-	-	
C	HEB	0.102	lbs SO2/000 lbs product	Direct measurement.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.

Table C-6
Sulfur Dioxide Emission Factors

Production Process	Stack Identification Code	Process Related Sulfur Dioxide Emissions			Annual Emissions		Basis for Combustion Emission Factor
		Emission Factor	Emission Factor Units	Basis for Emission Factor			
C	HNL	0.017	lbs SO2/000 lbs product	Direct measurement.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CBB	0.044	lbs SO2/000 lbs product	Process emission based on 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CTQ	0.028	lbs SO2/000 lbs product	Process emission based on 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CTR	0.024	lbs SO2/000 lbs product	Process emission based on 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CTS	0.010	lbs SO2/000 lbs product	Process emission based on 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CTT	0.012	lbs SO2/000 lbs product	Process emission based on 10% conversion of sulfite to SO2 within process. Emission allocated among stacks based on drying profile and stack exhaust rates.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CNV	0.010	lbs SO2/000 lbs product	The sum of CNV, CNW, CTU, and CTZ assumed to be the same as the sum of HEB and HNL. Emissions allocated to specific stacks within the process is porportional to the drying profile and stack.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CNW	0.010	lbs SO2/000 lbs product	The sum of CNV, CNW, CTU, and CTZ assumed to be the same as the sum of HEB and HNL. Emissions allocated to specific stacks within the process is porportional to the drying profile and stack.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	CTU	0.067	lbs SO2/000 lbs product	The sum of CNV, CNW, CTU, and CTZ assumed to be the same as the sum of HEB and HNL. Emissions allocated to specific stacks within the process is porportional to the drying profile and stack.	-	-	
C	CTZ	0.032	lbs SO2/000 lbs product	The sum of CNV, CNW, CTU, and CTZ assumed to be the same as the sum of HEB and HNL. Emissions allocated to specific stacks within the process is porportional to the drying profile and stack.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.

Table C-6
Sulfur Dioxide Emission Factors

Production Process	Stack Identification Code	Process Related Sulfur Dioxide Emissions					
		Emission Factor	Emission Factor Units	Basis for Emission Factor	Annual Emissions		Basis for Combustion Emission Factor
C	TCD	0.119	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission allocated to stack with applied heat.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	TAC	0.040	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission divided equally between TAC and TAH.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
C	TAH	0.040	lbs SO2/000 lbs product	Estimated 10% conversion of sulfite to SO2 within process. Emission divided equally between TAC and TAH.	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.
Plant	Heaters	-	NA	NA	0.0024	lb SO2/MMBtu	Based on AP-42, Table 1.4-2 (7/98), for uncontrolled combustion and assuming 1020 BTU/scf and 0.8 gr/Ccf sulfur content of natural gas.

Table C-7
Estimated Sulfur Dioxide Emissions

Production Process	Stack Identification Code	Process Emissions			Combustion Emissions: Annual Emissions				Combined Annual Emissions, tpy
		Emission Factor	Emission Factor Units	Annual Operating Rate	Emission Factor	Emission Factor Units	Operating Rate	Operating Units	
Boilers	Boiler 1	*NA*			*Enforceable limit from PTC P-050301 (10/05)*				
Boilers	Boiler 2								
Boilers	Boiler 3								
Boilers	Boilers 1 and 2								
Boilers	Boilers 1, 2, and 3								145.0
A	DHT	0.005	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30
A	DHU	0.0050	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30
A	DHZ	0.005	lbs SO2/000 lbs unit process throughput	183,960	0.0024	lb SO2/MMBtu	52,560	MMBtu	0.52
B	DUQ	0.005	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30
B	DUT	0.005	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30
B	DQA	0.005	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30

Table C-7
Estimated Sulfur Dioxide Emissions

Production Process	Stack Identification Code	Process Emissions			Combustion Emissions Annual Emissions				Combined Annual Emissions, tpy
		Emission Factor	Emission Factor Units	Annual Operating Rate	Emission Factor	Emission Factor Units	Operating Rate	Operating Units	
B	DQB	0.005	lbs SO2/000 lbs unit process throughput	91,980	0.0024	lb SO2/MMBtu	61,320	MMBtu	0.30
B	DUV	0.005	lbs SO2/000 lbs unit process throughput	367,920	0.0024	lb SO2/MMBtu	105,120	MMBtu	1.05
B	DSO	0.005	lbs SO2/000 lbs unit process throughput	45,990	-	-	-	-	0.11
C	ALB	0.011	lbs SO2/000 lbs product	16,057	-	-	-	-	0.08
C	ALQ	0.011	lbs SO2/000 lbs product	16,057	-	-	-	-	0.08
C	ALV	0.011	lbs SO2/000 lbs product	26,280	-	-	-	-	0.14
C	ALW	0.011	lbs SO2/000 lbs product	26,280	-	-	-	-	0.14
C	AEV	0.011	lbs SO2/000 lbs product	17,520	0.0024	lb SO2/MMBtu	28,908	MMBtu	0.13

Table C-7
Estimated Sulfur Dioxide Emissions

Production Process	Stack Identification Code	Process Emissions			Combustion Emissions Annual Emissions				Combined Annual Emissions, tpy
		Emission Factor	Emission Factor Units	Annual Operating Rate	Emission Factor	Emission Factor Units	Operating Rate	Operating Units	
C	AEW	0.011	lbs SO2/000 lbs product	17,520	-	-	-	-	0.09
C	CIR_RTC	0.110	lbs SO2/000 lbs product	74,460	-	-	-	-	4.10
C	CXX	0.058	lbs SO2/000 lbs product	43,800	0.0024	lb SO2/MMBtu	93,951	MMBtu	1.38
C	CYY	0.061	lbs SO2/000 lbs product	43,800	0.0024	lb SO2/MMBtu	65,919	MMBtu	1.42
C	CHX	0.000	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	68,503	MMBtu	0.08
C	CHY	0.019	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	40,471	MMBtu	0.20
C	CHZ	0.026	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	19,798	MMBtu	0.23
C	TEE	0.029	lbs SO2/000 lbs product	15,698	-	-	-	-	0.23
C	TEM	0.031	lbs SO2/000 lbs product	15,698	-	-	-	-	0.24

Table C-7
Estimated Sulfur Dioxide Emissions

Production Process	Stack Identification Code	Process Emissions			Combustion Emissions Annual Emissions				Combined Annual Emissions, tpy
		Emission Factor	Emission Factor Units	Annual Operating Rate	Emission Factor	Emission Factor Units	Operating Rate	Operating Units	
C	HEB	0.102	lbs SO2/000 lbs product	19,272	0.0024	lb SO2/MMBtu	94,433	MMBtu	1.10
C	HNL	0.017	lbs SO2/000 lbs product	19,272	0.0024	lb SO2/MMBtu	28,207	MMBtu	0.20
C	CBB	0.044	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	13,140	MMBtu	0.36
C	CTQ	0.028	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	35,097	MMBtu	0.27
C	CTR	0.024	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	57,715	MMBtu	0.26
C	CTS	0.010	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	76,931	MMBtu	0.17
C	CTT	0.012	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	84,971	MMBtu	0.20
C	CNV	0.010	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	105,120	MMBtu	0.21
C	CNW	0.010	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	105,120	MMBtu	0.21
C	CTU	0.067	lbs SO2/000 lbs product	15,698	-	-	-	-	0.52

Table C-7
Estimated Sulfur Dioxide Emissions

Production Process	Stack Identification Code	Process Emissions			Combustion Emissions Annual Emissions				Combined Annual Emissions, tpy
		Emission Factor	Emission Factor Units	Annual Operating Rate	Emission Factor	Emission Factor Units	Operating Rate	Operating Units	
C	CTZ	0.032	lbs SO2/000 lbs product	15,698	0.0024	lb SO2/MMBtu	94,608	MMBtu	0.36
C	TCD	0.119	lbs SO2/000 lbs product	8,760	0.0024	lb SO2/MMBtu	17,520	MMBtu	0.54
C	TAC	0.040	lbs SO2/000 lbs product	3,504	0.0024	lb SO2/MMBtu	10,950	MMBtu	0.08
C	TAH	0.040	lbs SO2/000 lbs product	3,504	0.0024	lb SO2/MMBtu	10,950	MMBtu	0.08
Plant	Heaters	0.00000	NA	-	0.0024	lb SO2/MMBtu	679,561	MMBtu	0.82

Table C-8
Particulate Matter Emission Factors

Production Process	Stack Identification Code	Emission Factor	Emission Factor Units	Basis for Factor
Boilers	Boiler 1	0.083	lb/000 lbs steam	#6 oil firing with scrubber control
Boilers	Boiler 2	0.084	lb/000 lbs steam	#6 oil firing with scrubber control
Boilers	Boiler 3	0.013	lb/000 lbs steam	weighted averate for #2 oil and natural gas firing
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHQ	0.016	lb PM/ 000 lb unit process throughput	Based on June 2006 Method 201/202 PM-10 testing. Filterable PM10 assumed to be 58.1% of Filterable PM, based on fractioning from emission measurements of stack DUT.
A	DHT	0.141	lb PM/ 000 lb unit process throughput	Assumed to be the same as DUT
A	DHU	0.141	lb PM/ 000 lb unit process throughput	Assumed to be the same as DUT
A	DHZ	0.116	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5).
A	DKV	0.161	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
A	DKW	0.005	lb PM/ 000 lb process output	Assumed to be the same as DUY
B	DXS	0.0090	lb PM/ 000 lb unit process throughput	Assumed to be the same as DPY
B	DUO	0.0090	lb PM/ 000 lb unit process throughput	Assumed to be the same as DPY
B	DPY	0.0090	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Total condensible emission for stacks DXS, DUO, DPY, and DPZ assumed to be the same as stack DHQ; condensible emissions divided equally among these four stacks.
B	DPZ	0.0090	lb PM/ 000 lb unit process throughput	Assumed to be the same as DPY
B	DUQ	0.141	lb PM/ 000 lb unit process throughput	Assumed to be the same as DUT
B	DUT	0.141	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5). Emission factor assumed to be the higher of two seperate Method 5 emission measurements from this stack.
B	DQA	0.141	lb PM/ 000 lb unit process throughput	Assumed to be the same as DUT
B	DQB	0.141	lb PM/ 000 lb unit process throughput	Assumed to be the same as DUT

Table C-8
Particulate Matter Emission Factors

Production Process	Stack Identification Code	Emission Factor	Emission Factor Units	Basis for Factor
B	DUV	0.029	lb PM/ 000 lb unit process throughput	Based on Nov. 2011 Methods 201A & 202 testing of Stack DUV for coarse PM, PM-10 and CPM. Emission factor is 125% of measured emission rate.
B	DSO	0.053	lb PM/ 000 lb unit process throughput	Direct measurement of solid particulates via Oregon Method 8; condensibles assumed to be the same as DHZ.
B	DSK	0.015	lb PM/ 000 lb unit process throughput	Solid particulates assumed to be the same as DSO. Condensible emission assumed to be negligible.
B	DUY	0.005	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
B	DUZ	0.005	lb PM-10/ 000 lb unit process throughput	Assumed to be the same as DUY
B	DRY	0.008	lb PM/ 000 lb unit process throughput	Based on direct measurement of solid fraction (Oregon Method 8) from former stack DUU. Condensible emission assumed to be negligible.
C	ALB	0.085	lb PM/ 000 lb unit process output	Direct measurement of solid fraction (Oregon Method 8). Overall dryer condensibles assumed to be the same as the average of those measured in DUT and DHZ.; one-half allocated to each of the first two stacks from this dryer.
C	ALQ	0.045	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Overall dryer condensibles assumed to be the same as the average of those measured in DUT and DHZ.; one-half allocated to each of the first two stacks from this dryer.
C	ALT	0.008	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
C	ALY	0.003	lb PM/ 000 lb unit process throughput	Assumed to be the same as CHV
C	ALV	0.085	lb PM/ 000 lb process throughput	Assumed to be the same as ALB
C	ALW	0.045	lb PM/ 000 lb unit process throughput	Assumed to be the same as ALQ
C	ALX	0.008	lb PM/ 000 lb unit process throughput	Assumed to be the same as ALT
C	AEV	0.085	lb PM/ 000 lb unit process throughput	Assumed to be the same as ALB.
C	AEW	0.053	lb PM/ 000 lb unit process throughput	Assumed to be the same as the sum of ALT and ALQ.
C	AGQ	0.003	lb PM/ 000 lb unit process throughput	Assumed to be the same as CHV

Table C-8
Particulate Matter Emission Factors

Production Process	Stack Identification Code	Emission Factor	Emission Factor Units	Basis for Factor
C	CIR_RTC	0.046	lb PM/ 000 lb unit process throughput	Based on Nov. 2011 testing of Stack CIR_RTC for PM and CPM. Emission factor is 25% larger than measured emission.
C	CHV	0.003	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
C	CXX	0.450	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5).
C	CYY	0.380	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5).
C	CHX	0.253	lb PM/ 000 lb unit process throughput	The sum of filterable PM emissins from Stacks CHX, CHY, CHZ, TEE, and TEM assumed to be the same the sum of filterable PM emissions from Stacks HEB and HNL. Within the production line filterable PM emissions allocated to stack using the same emissions as was observed for filterable PM-10 emissions in November 2011 stack testing. Condensible emissions derived from November 2011 stack testing of stacks CHX, CHY, CHZ, and TEE. Stack TEM assumed to be the same as TEE. Emission factors used are 125% of the referenced measured emission rates.
C	CHY	0.088	lb PM/ 000 lb unit process throughput	
C	CHZ	0.064	lb PM/ 000 lb unit process throughput	
C	TEE	0.021	lb PM/ 000 lb unit process throughput	
C	TEM	0.021	lb PM/ 000 lb unit process throughput	
C	HEB	0.739	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5).
C	HNL	0.176	lb PM/ 000 lb unit process throughput	Direct measurement (EPA Method 5).
C	CBB	0.121	lb PM/ 000 lb unit process throughput	Total production line emission factors for filterable PM for stacks CBB, CTO

Table C-8
Particulate Matter Emission Factors

Production Process	Stack Identification Code	Emission Factor	Emission Factor Units	Basis for Factor
C	CTQ	0.114	lb PM/ 000 lb unit process throughput	Total production line emission factors for filterable PM for stacks CBB, CTQ, CTR, CTS and CTT are assumed to be the same as for the production line served by stacks HEB and HNL. Total production line emission factors for condensable PM for stacks CBB, CTQ, CTR, CTS and CTT are assumed to be the same as was measured during condensable emissions testing of Stacks CHX, CHY, CHZ, TEE, and TEM in November 2011. Within the production line filterable and condensable PM emissions are allocated to individual stacks using the same emissions profiles for these parameters as was observed in November 2011 stack testing of stacks CHX, CHY, CHZ, TEE, and TEM. Emission factors used are 125% of the referenced measured emission rates. See *"Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors"* for details.
C	CTR	0.119	lb PM/ 000 lb unit process throughput	
C	CTS	0.045	lb PM/ 000 lb unit process throughput	
C	CTT	0.048	lb PM/ 000 lb unit process throughput	
C	CNV	0.075	lb PM/ 000 lb unit process throughput	Based on process similarity, total production line emission factors for filterable PM and condensible particulate matter (CPM) for stacks CNV, CNW, CTU, CTQ,CTR, CTS and CTT are assumed to be the same as for the production line served by stacks HEB and HNL. Filterable PM and CPM emissions allocated to individuall stacks based on the emissions profile for filterable PM and CPM as a function of product drying observed during Nov. 2011 stack testing of stacks CHX, CHY, CHZ, TEE, and TEM. See *"Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors"* for details.
C	CNW	0.078	lb PM/ 000 lb unit process throughput	
C	CTU	0.572	lb PM/ 000 lb unit process throughput	
C	CTZ	0.189	lb PM/ 000 lb unit process throughput	
C	TCD	0.0342	lb PM/ 000 lb unit process throughput	PM Emission factor for bean drying at Plover facility divided equally between stacks TCD and TCO.
C	TCO	0.0342	lb PM/ 000 lb unit process throughput	PM Emission factor for bean drying at Plover facility divided equally between stacks TCD and TCO.

Table C-8
Particulate Matter Emission Factors

Production Process	Stack Identification Code	Emission Factor	Emission Factor Units	Basis for Factor
C	TAC	0.458	lb PM/ 000 lb unit process throughput	The sum of TAC and TAH assumed to be the same as the sum of HEB and HNL. Emissions divided equally between stacks.
C	TAH	0.458	lb PM/ 000 lb unit process throughput	The sum of TAC and TAH assumed to be the same as the sum of HEB and HNL. Emissions divided equally between stacks.
C	EUW	0.000	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
C	SUF	0.000	lb PM/ 000 lb unit process throughput	Assumed to be the same as EUW.
C	DSX	0.016	lb PM/ 000 lb unit process throughput	Based on direct measurement of solid fraction (Oregon Method 8) from former stack CHI. Condensible emission assumed to be negligible.
C	EGS	0.003	lb PM/ 000 lb unit process throughput	Assumed to be the same as EGT.
C	EGT	0.003	lb PM/ 000 lb unit process throughput	Direct measurement of solid fraction (Oregon Method 8). Condensible emission assumed to be negligible.
C	FIF	0.038	lb PM/ 000 lb unit process throughput	Derived from AP-42, Table 9.9.1-1 (5/98) for Internal Vibrating Grain Cleaning with cyclone control. Filterable PM emission factor is 0.075 lb/ton of grain processed.
Plant	Heaters	0.007	lb PM/MM Btu	AP-42 Table 1.4-2. On an annual basis, firing assumed to occur at a maximum of 50% of burner capacity.
Plant	Fugitive Dust	5.200	lb PM/hr	AP-42 Section 13.2. Emission listed is for dry conditions, appropriate for daily emission rates.

Table C-9
Estimated Particulate Matter Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	0.083	lb/000 lbs steam	230,966	MM lbs steam	9.56
Boilers	Boiler 2	0.084	lb/000 lbs steam	282,292	MM lbs steam	11.80
Boilers	Boiler 3	0.013	lb/000 lbs steam	262,800	MM lbs steam	1.71
Boilers	Boilers 1 and 2					0.0
Boilers	Boilers 1, 2, and 3					0.0
A	DHQ	0.016	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	1.44
A	DHT	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
A	DHU	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
A	DHZ	0.116	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	10.67
A	DKV	0.161	lb PM/ 000 lb unit process throughput	22,995	000 lbs throughput/yr	1.85
A	DKW	0.005	lb TSP/ 000 lb process throughput (including mixback)	22,995	000 lbs throughput/yr	0.06
B	DXS	0.009	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.83
B	DUO	0.009	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.83
B	DPY	0.009	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.83
B	DPZ	0.009	lb PM/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.83
B	DUQ	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
B	DUT	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
B	DQA	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
B	DQB	0.141	lb PM/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	6.48
B	DUV	0.029	lb PM/ 000 lb unit process throughput	367,920	000 lbs throughput/yr	5.32
B	DSO	0.053	lb PM/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	1.22
B	DSK	0.015	lb PM/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.34

Table C-9
Estimated Particulate Matter Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
B	DUY	0.005	lb PM/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.11
B	DUZ	0.005	lb PM/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.11
B	DRY	0.008	lb PM/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.18
C	ALB	0.085	lb PM/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.68
C	ALQ	0.045	lb PM/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.36
C	ALT	0.008	lb PM/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.06
C	ALY	0.003	lb PM/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.02
C	ALV	0.085	lb PM/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	1.12
C	ALW	0.045	lb PM/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	0.59
C	ALX	0.008	lb PM/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	0.11
C	AEV	0.085	lb PM/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.74
C	AEW	0.053	lb PM/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.46
C	AGQ	0.003	lb PM/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.03
C	CIR_RTC	0.046	lb PM/ 000 lb unit process throughput	74,460	000 lbs throughput/yr	1.72
C	CHV	0.003	lb PM/ 000 lb unit process throughput	74,460	000 lbs throughput/yr	0.11
C	CXX	0.450	lb PM/ 000 lb unit process throughput	43,800	000 lbs throughput/yr	9.86
C	CYY	0.380	lb PM/ 000 lb unit process throughput	43,800	000 lbs throughput/yr	8.32
C	CHX	0.253	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	1.99
C	CHY	0.088	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.69
C	CHZ	0.064	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.50

Table C-9
Estimated Particulate Matter Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	TEE	0.021	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.17
C	TEM	0.021	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.17
C	HEB	0.739	lb PM/ 000 lb unit process throughput	19,272	000 lbs throughput/yr	7.12
C	HNL	0.176	lb PM/ 000 lb unit process throughput	19,272	000 lbs throughput/yr	1.70
C	CBB	0.121	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.95
C	CTQ	0.114	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.90
C	CTR	0.119	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.94
C	CTS	0.045	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.35
C	CTT	0.048	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.38
C	CNV	0.075	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.59
C	CNW	0.078	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.61
C	CTU	0.572	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	4.49
C	CTZ	0.189	lb PM/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	1.49
C	TCD	0.034	lb PM/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.15
C	TCO	0.034	lb PM/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.15
C	TAC	0.458	lb PM/ 000 lb unit process throughput	3,504	000 lbs throughput/yr	0.80
C	TAH	0.458	lb PM/ 000 lb unit process throughput	3,504	000 lbs throughput/yr	0.80
C	EUW	0.000	lb PM/ 000 lb unit process throughput	376,680	000 lbs throughput/yr	0.02
C	SUF	0.000	lb PM/ 000 lb unit process throughput	376,680	000 lbs throughput/yr	0.02
C	DSX	0.016	lb PM/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.07

Table C-9
Estimated Particulate Matter Emissions

Production Process	Stack Identification Code	Annual Emissions					
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	EGS	0.003	lb PM/ 000 lb unit process throughput	55,684	000 lbs throughput/yr	0.08
C	EGT	0.003	lb PM/ 000 lb unit process throughput	55,684	000 lbs throughput/yr	0.08
C	FIF	0.038	lb PM/ 000 lb unit process throughput	6,899	000 lbs throughput/yr	0.13
Plant	Heaters	0.0075	lb PM/MM Btu	339,781	MMBtu/yr	1.27
Plant	Fugitive Dust	5.2	lb PM/hr	7,358	hrs/yr	4.78

Note: Fugitive Dust annual hours adjusted to incorporate net effects of precipitation corre

Table C-10
PM-10 Emission Factors

Production Process	Stack Identification Code
Boilers	Boiler 1
Boilers	Boiler 2
Boilers	Boiler 3
Boilers	Boilers 1 and 2
Boilers	Boilers 1, 2, and 3
A	DHQ
A	DHT
A	DHU
A	DHZ
A	DKV
A	DKW
B	DXS
B	DUO
B	DPY
B	DPZ
B	DUQ
B	DUT
B	DQA

Table C-10
PM-10 Emission Factors

Production Process	Stack Identification Code
B	DQB
B	DUV
B	DSO
B	DSK
B	DUY
B	DUZ
B	DRY
C	ALB
C	ALQ
C	ALT
C	ALY
C	ALV
C	ALW
C	ALX
C	AEV
C	AEW
C	AGQ

Table C-10
PM-10 Emission Factors

Production Process	Stack Identification Code
C	CIR_RTC
C	CHV
C	CXX
C	CYY
C	CHX
C	CHY
C	CHZ
C	TEE
C	TEM
C	HEB
C	HNL
C	CBB
C	CTQ

Table C-10
PM-10 Emission Factors

Production Process	Stack Identification Code
C	CTR
C	CTS
C	CTT
C	CNV
C	CNW
C	CTU
C	CTZ
C	TCD
C	TCO
C	TAC
C	TAH
C	EUW
C	SUF

Table C-10
PM-10 Emission Factors

Production Process	Stack Identification Code
C	DSX
C	EGS
C	EGT
C	FIF
Plant	Heaters
Plant	Fugitive Dust

Table C-11
Estimated PM-10 Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	*Enforceable limit from PTC P-050301 (10/05)*				
Boilers	Boiler 2					
Boilers	Boiler 3					
Boilers	Boilers 1 and 2					
Boilers	Boilers 1, 2, and 3					18.3
A	DHQ	0.015	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	1.38
A	DHT	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
A	DHU	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
A	DHZ	0.083	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	7.63
A	DKV	0.094	lb PM-10/ 000 lb unit process throughput	22,995	000 lbs throughput/yr	1.08
A	DKW	0.003	lb TSP/ 000 lb process throughput (including mixback)	22,995	000 lbs throughput/yr	0.03
B	DXS	0.008	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.76
B	DUO	0.008	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.76
B	DPY	0.008	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.76
B	DPZ	0.008	lb PM-10/ 000 lb unit process throughput	183,960	000 lbs throughput/yr	0.76
B	DUQ	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
B	DUT	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
B	DQA	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
B	DQB	0.110	lb PM-10/ 000 lb unit process throughput	91,980	000 lbs throughput/yr	5.06
B	DUV	0.019	lb PM-10/ 000 lb unit process throughput	367,920	000 lbs throughput/yr	3.58
B	DSO	0.046	lb PM-10/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	1.06

Table C-11
Estimated PM-10 Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
B	DSK	0.008	lb PM-10/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.18
B	DUY	0.003	lb PM-10/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.07
B	DUZ	0.003	lb PM-10/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.07
B	DRY	0.004	lb PM-10/ 000 lb unit process throughput	45,990	000 lbs throughput/yr	0.09
C	ALB	0.055	lb PM-10/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.44
C	ALQ	0.035	lb PM-10/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.28
C	ALT	0.004	lb PM-10/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.03
C	ALY	0.001	lb PM-10/ 000 lb unit process throughput	16,057	000 lbs throughput/yr	0.01
C	ALV	0.055	lb PM-10/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	0.72
C	ALW	0.035	lb PM-10/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	0.46
C	ALX	0.004	lb PM-10/ 000 lb unit process throughput	26,280	000 lbs throughput/yr	0.05
C	AEV	0.055	lb PM-10/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.48
C	AEW	0.039	lb PM-10/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.34
C	AGQ	0.001	lb PM-10/ 000 lb unit process throughput	17,520	000 lbs throughput/yr	0.01
C	CIR_RTC	0.046	lb PM-10/ 000 lb unit process throughput	74,460	000 lbs throughput/yr	1.72
C	CHV	0.001	lb PM-10/ 000 lb unit process throughput	74,460	000 lbs throughput/yr	0.03
C	CXX	0.343	lb PM-10/ 000 lb unit process throughput	43,800	000 lbs throughput/yr	7.51
C	CYY	0.327	lb PM-10/ 000 lb unit process throughput	43,800	000 lbs throughput/yr	7.16

Table C-11
Estimated PM-10 Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	CHX	0.190	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	1.49
C	CHY	0.063	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.50
C	CHZ	0.033	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.26
C	TEE	0.009	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.07
C	TEM	0.009	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.07
C	HEB	0.640	lb PM-10/ 000 lb unit process throughput	19,272	000 lbs throughput/yr	6.17
C	HNL	0.142	lb PM-10/ 000 lb unit process throughput	19,272	000 lbs throughput/yr	1.37
C	CBB	0.101	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.79
C	CTQ	0.081	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.63
C	CTR	0.078	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.61
C	CTS	0.024	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.19
C	CTT	0.020	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.16
C	CNV	0.074	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.58
C	CNW	0.075	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	0.59
C	CTU	0.505	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	3.96
C	CTZ	0.128	lb PM-10/ 000 lb unit process throughput	15,698	000 lbs throughput/yr	1.00
C	TCD	0.034	lb PM-10/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.15
C	TCO	0.034	lb PM-10/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.15

Table C-11
Estimated PM-10 Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	TAC	0.391	lb PM-10/ 000 lb unit process throughput	3,504	000 lbs throughput/yr	0.69
C	TAH	0.391	lb PM-10/ 000 lb unit process throughput	3,504	000 lbs throughput/yr	0.69
C	EUW	0.000	lb PM-10/ 000 lb unit process throughput	376,680	000 lbs throughput/yr	0.02
C	SUF	0.000	lb PM-10/ 000 lb unit process throughput	376,680	000 lbs throughput/yr	0.02
C	DSX	0.009	lb PM-10/ 000 lb unit process throughput	8,760	000 lbs throughput/yr	0.04
C	EGS	0.002	lb PM-10/ 000 lb unit process throughput	55,684	000 lbs throughput/yr	0.04
C	EGT	0.002	lb PM-10/ 000 lb unit process throughput	55,684	000 lbs throughput/yr	0.04
C	FIF	0.038	lb PM-10/ 000 lb unit process throughput	6,899	000 lbs throughput/yr	0.13
Plant	Heaters	0.007	lb PM-10/MM Btu	339,781	MM Btu/yr	1.27
Plant	Fugitive Dust			7,621 (see note)	hrs/yr	3.07

Note: Fugitive Dust annual hours adjusted to incorporate net effects of precipitation corrections calculated pe

Table C-12
VOC Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
Boilers	Boiler 1	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted. Natural gas has the highest emission factor of any fuel available for boiler firing.
Boilers	Boiler 2	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted. Natural gas has the highest emission factor of any fuel available for boiler firing.
Boilers	Boiler 3	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted. Natural gas has the highest emission factor of any fuel available for boiler firing.
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
A	DHU	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
A	DHZ	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
B	DUQ	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
B	DUT	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
B	DQA	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
B	DQB	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
B	DUV	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	AEV	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CXX	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CYY	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CHX	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CHY	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CHZ	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.

Table C-12
VOC Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
C	HEB	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	HNL	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CBB	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CTQ	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CTR	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CTS	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CTT	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CNV	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CNW	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	CTZ	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	TCD	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	TAC	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
C	TAH	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.
Plant	Heaters	0.0054	lbs VOC/ MM Btu	Based on AP-42 emission factor of 5.5 lbs/1000 scf of natural gas combusted.

Table C-13
Estimated VOC Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	0.0054	lbs VOC/ MM Btu	483,700	MMBtu	1.3
Boilers	Boiler 2	0.0054	lbs VOC/ MM Btu	666,662	MMBtu	1.8
Boilers	Boiler 3	0.0054	lbs VOC/ MM Btu	342,078	MMBtu	0.9
Boilers	Boilers 1 and 2					0.0
Boilers	Boilers 1, 2, and 3					0.0
A	DHT	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
A	DHU	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
A	DHZ	0.0054	lbs VOC/ MM Btu	52,560	MMBtu	0.1
B	DUQ	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
B	DUT	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
B	DQA	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
B	DQB	0.0054	lbs VOC/ MM Btu	61,320	MMBtu	0.2
B	DUV	0.0054	lbs VOC/ MM Btu	105,120	MMBtu	0.3
C	AEV	0.0054	lbs VOC/ MM Btu	28,908	MMBtu	0.1
C	CXX	0.0054	lbs VOC/ MM Btu	93,951	MMBtu	0.3
C	CYY	0.0054	lbs VOC/ MM Btu	65,919	MMBtu	0.2
C	CHX	0.0054	lbs VOC/ MM Btu	68,503	MMBtu	0.2
C	CHY	0.0054	lbs VOC/ MM Btu	40,471	MMBtu	0.1
C	CHZ	0.0054	lbs VOC/ MM Btu	19,798	MMBtu	0.1
C	HEB	0.0054	lbs VOC/ MM Btu	94,433	MMBtu	0.3
C	HNL	0.0054	lbs VOC/ MM Btu	28,207	MMBtu	0.1
C	CBB	0.0054	lbs VOC/ MM Btu	13,140	MMBtu	0.0
C	CTQ	0.0054	lbs VOC/ MM Btu	35,097	MMBtu	0.1
C	CTR	0.0054	lbs VOC/ MM Btu	57,715	MMBtu	0.2
C	CTS	0.0054	lbs VOC/ MM Btu	76,931	MMBtu	0.2
C	CTT	0.0054	lbs VOC/ MM Btu	84,971	MMBtu	0.2
C	CNV	0.0054	lbs VOC/ MM Btu	105,120	MMBtu	0.3
C	CNW	0.0054	lbs VOC/ MM Btu	105,120	MMBtu	0.3
C	CTZ	0.0054	lbs VOC/ MM Btu	94,608	MMBtu	0.3
C	TCD	0.0054	lbs VOC/ MM Btu	17,520	MMBtu	0.0
C	TAC	0.0054	lbs VOC/ MM Btu	10,950	MMBtu	0.0

Table C-13
Estimated VOC Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	TAH	0.0054	lbs VOC/ MM Btu	10,950	MMBtu	0.0
Plant	Heaters	0.0054	lbs VOC/ MM Btu	679,561	MMBtu	1.8

Table C-14
Lead Emission Factors

Production Process	Stack Identification Code	Annual emissions		
		Emission Factor	Emission Factor Units	Basis for Factor
Boilers	Boiler 1	4.5E-06	lbs Pb/ MM Btu	Maximum of Pb emission factors for natural gas, No. 2 oil, and No. 6 oil. AP-42 factors used for natural gas and #2 oil. Emission factor selected is the one that yields the highest emission rate after multipled by the boiler operating rate for that fuel. 50% remvoval of Pb assumed in wet scrubber when fuel oil combusted.
Boilers	Boiler 2	4.50E-06	lbs Pb/ MM Btu	Maximum of Pb emission factors for natural gas, No. 2 oil, and No. 6 oil. AP-42 factors used for natural gas and #2 oil. Emission factor selected is the one that yields the highest emission rate after multipled by the boiler operating rate for that fuel. 50% remvoval of Pb assumed in wet scrubber when fuel oil combusted.
Boilers	Boiler 3	1.9E-06	lbs Pb/ MM Btu	Weighted average based on 1440 hrs oil firing at 9E-6 lb Pb/MMBtu (AP-42 emission factor for #2 oil firing) and 7128 hrs natural gas firing at 4.9E-7 lbs Pb Pb/MMBtu (AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted).
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
A	DHU	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
A	DHZ	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
B	DUQ	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
B	DUT	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
B	DQA	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
B	DQB	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
B	DUV	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	AEV	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	CXX	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	CYY	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	CHX	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CHY	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CHZ	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	HEB	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Pb emission factor allocated to HEB and HNL in proportion to measured heat rates at each stack.
C	HNL	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Pb emission factor allocated to HEB and HNL in proportion to measured heat rates at each stack.
C	CBB	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.

Table C-14
Lead Emission Factors

Production Process	Stack Identification Code	Annual emissions		
		Emission Factor	Emission Factor Units	Basis for Factor
C	CTQ	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CTR	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CTS	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CTT	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Emissions allocated to specific stacks within the process in proportion to stack exhaust rate.
C	CNV	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	CNW	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	CTZ	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	TCD	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.
C	TAC	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Allocated equally between stacks TAC and TAH.
C	TAH	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. Allocated equally between stacks TAC and TAH.
Plant	Heaters	4.9E-07	lbs Pb/ MM Btu	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted. On an annual basis, firing assumed to occur at a maximum of 50% of burner capacity.

Table C-15
Estimated Lead Emissions

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor, lb Pb/MMBtu	Operating Factor, MMBtu/yr	Emissions, ton/yr
Boilers	Boiler 1	4.50E-06	325,171	7.32E-04
Boilers	Boiler 2	4.50E-06	643,510	1.45E-03
Boilers	Boiler 3	1.92E-06	341,640	3.28E-04
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	4.90E-07	61,320	1.50E-05
A	DHU	4.90E-07	61,320	1.50E-05
A	DHZ	4.90E-07	52,560	1.29E-05
B	DUQ	4.90E-07	61,320	1.50E-05
B	DUT	4.90E-07	61,320	1.50E-05
B	DQA	4.90E-07	61,320	1.50E-05
B	DQB	4.90E-07	61,320	1.50E-05
B	DUV	4.90E-07	105,120	2.58E-05
C	AEV	4.90E-07	28,908	7.09E-06
C	CXX	4.90E-07	93,951	2.30E-05
C	CYY	4.90E-07	65,919	1.62E-05
C	CHX	4.90E-07	68,503	1.68E-05
C	CHY	4.90E-07	40,471	9.92E-06
C	CHZ	4.90E-07	19,798	4.85E-06
C	HEB	4.90E-07	94,433	2.31E-05
C	HNL	4.90E-07	28,207	6.91E-06
C	CBB	4.90E-07	13,140	3.22E-06
C	CTQ	4.90E-07	35,097	8.60E-06
C	CTR	4.90E-07	57,715	1.41E-05
C	CTS	4.90E-07	76,931	1.89E-05
C	CTT	4.90E-07	84,971	2.08E-05
C	CNV	4.90E-07	105,120	2.58E-05
C	CNW	4.90E-07	105,120	2.58E-05
C	CTZ	4.90E-07	94,608	2.32E-05
C	TCD	4.90E-07	17,520	4.29E-06
C	TAC	4.90E-07	10,950	2.68E-06

Table C-15
Estimated Lead Emissions

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor, lb Pb/MMBtu	Operating Factor, MMBtu/yr	Emissions, ton/yr
C	TAH	4.90E-07	10,950	2.68E-06
Plant	Heaters	4.90E-07	679,561	1.67E-04

Table C-16
GHG Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
Boilers	Boiler 1	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boiler 2	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boiler 3	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
A	DHU	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
A	DHZ	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUQ	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUT	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DQA	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DQB	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUV	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	AEV	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CXX	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CYY	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CHX	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CHY	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.

Table C-16
GHG Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
C	CHZ	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	HEB	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	HNL	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CBB	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTQ	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTR	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTS	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTT	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CNV	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CNW	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTZ	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TCD	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TAC	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TAH	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
Plant	Heaters	118	lbs GHG/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.

Table C-17
Estimated GHG Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	117.6471	lbs GHG/ MM Btu	483,700	MMBtu	28453.0
Boilers	Boiler 2	117.6471	lbs GHG/ MM Btu	666,662	MMBtu	39215.4
Boilers	Boiler 3	117.6471	lbs GHG/ MM Btu	342,078	MMBtu	20122.2
Boilers	Boilers 1 and 2					
Boilers	Boilers 1, 2, and 3					
A	DHT	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
A	DHU	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
A	DHZ	117.6471	lbs GHG/ MM Btu	52,560	MMBtu	3091.8
B	DUQ	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
B	DUT	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
B	DQA	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
B	DQB	117.6471	lbs GHG/ MM Btu	61,320	MMBtu	3607.1
B	DUV	117.6471	lbs GHG/ MM Btu	105,120	MMBtu	6183.5
C	AEV	117.6471	lbs GHG/ MM Btu	28,908	MMBtu	1700.5
C	CXX	117.6471	lbs GHG/ MM Btu	93,951	MMBtu	5526.5
C	CYY	117.6471	lbs GHG/ MM Btu	65,919	MMBtu	3877.6
C	CHX	117.6471	lbs GHG/ MM Btu	68,503	MMBtu	4029.6
C	CHY	117.6471	lbs GHG/ MM Btu	40,471	MMBtu	2380.7
C	CHZ	117.6471	lbs GHG/ MM Btu	19,798	MMBtu	1164.6
C	HEB	117.6471	lbs GHG/ MM Btu	94,433	MMBtu	5554.9
C	HNL	117.6471	lbs GHG/ MM Btu	28,207	MMBtu	1659.2
C	CBB	117.6471	lbs GHG/ MM Btu	13,140	MMBtu	772.9
C	CTQ	117.6471	lbs GHG/ MM Btu	35,097	MMBtu	2064.5
C	CTR	117.6471	lbs GHG/ MM Btu	57,715	MMBtu	3395.0
C	CTS	117.6471	lbs GHG/ MM Btu	76,931	MMBtu	4525.4
C	CTT	117.6471	lbs GHG/ MM Btu	84,971	MMBtu	4998.3
C	CNV	117.6471	lbs GHG/ MM Btu	105,120	MMBtu	6183.5
C	CNW	117.6471	lbs GHG/ MM Btu	105,120	MMBtu	6183.5
C	CTZ	117.6471	lbs GHG/ MM Btu	94,608	MMBtu	5565.2
C	TCD	117.6471	lbs GHG/ MM Btu	17,520	MMBtu	1030.6
C	TAC	117.6471	lbs GHG/ MM Btu	10,950	MMBtu	644.1

Table C-17
Estimated GHG Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	TAH	117.6471	lbs GHG/ MM Btu	10,950	MMBtu	644.1
Plant	Heaters	117.6471	lbs GHG/ MM Btu	679,561	MMBtu	39,974.2

Table C-18
CO2e Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
Boilers	Boiler 1	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boiler 2	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boiler 3	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted. Potential annual emissions are highest with natural gas combustion because there are no fuel comubstion when burning nattural gas.
Boilers	Boilers 1 and 2			
Boilers	Boilers 1, 2, and 3			
A	DHT	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
A	DHU	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
A	DHZ	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUQ	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUT	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DQA	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DQB	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
B	DUV	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	AEV	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CXX	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CYY	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CHX	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CHY	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.

Table C-18
CO2e Emission Factors

Production Process	Stack Identification Code	Annual Emissions		
		Emission Factor	Units	Basis for Factor
C	CHZ	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	HEB	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	HNL	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CBB	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTQ	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTR	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTS	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTT	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CNV	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CNW	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	CTZ	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TCD	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TAC	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
C	TAH	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.
Plant	Heaters	118	lbs CO2e/ MM Btu	Based on AP-42 emission factor of 120 lbs/1000 scf of natural gas combusted.

Table C-19
Estimated CO2e Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
Boilers	Boiler 1	118	lbs CO2e/ MM Btu	483,700	MMBtu	28626.0
Boilers	Boiler 2	118	lbs CO2e/ MM Btu	666,662	MMBtu	39454.0
Boilers	Boiler 3	118	lbs CO2e/ MM Btu	342,078	MMBtu	20244.6
Boilers	Boilers 1 and 2					
Boilers	Boilers 1, 2, and 3					
A	DHT	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
A	DHU	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
A	DHZ	118	lbs CO2e/ MM Btu	52,560	MMBtu	3110.6
B	DUQ	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
B	DUT	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
B	DQA	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
B	DQB	118	lbs CO2e/ MM Btu	61,320	MMBtu	3629.0
B	DUV	118	lbs CO2e/ MM Btu	105,120	MMBtu	6221.1
C	AEV	118	lbs CO2e/ MM Btu	28,908	MMBtu	1710.8
C	CXX	118	lbs CO2e/ MM Btu	93,951	MMBtu	5560.1
C	CYY	118	lbs CO2e/ MM Btu	65,919	MMBtu	3901.2
C	CHX	118	lbs CO2e/ MM Btu	68,503	MMBtu	4054.1
C	CHY	118	lbs CO2e/ MM Btu	40,471	MMBtu	2395.1
C	CHZ	118	lbs CO2e/ MM Btu	19,798	MMBtu	1171.6
C	HEB	118	lbs CO2e/ MM Btu	94,433	MMBtu	5588.7
C	HNL	118	lbs CO2e/ MM Btu	28,207	MMBtu	1669.3
C	CBB	118	lbs CO2e/ MM Btu	13,140	MMBtu	777.6
C	CTQ	118	lbs CO2e/ MM Btu	35,097	MMBtu	2077.1
C	CTR	118	lbs CO2e/ MM Btu	57,715	MMBtu	3415.7
C	CTS	118	lbs CO2e/ MM Btu	76,931	MMBtu	4552.9
C	CTT	118	lbs CO2e/ MM Btu	84,971	MMBtu	5028.7
C	CNV	118	lbs CO2e/ MM Btu	105,120	MMBtu	6221.1
C	CNW	118	lbs CO2e/ MM Btu	105,120	MMBtu	6221.1
C	CTZ	118	lbs CO2e/ MM Btu	94,608	MMBtu	5599.0
C	TCD	118	lbs CO2e/ MM Btu	17,520	MMBtu	1036.9
C	TAC	118	lbs CO2e/ MM Btu	10,950	MMBtu	648.0

Table C-19
Estimated CO2e Emissions

Production Process	Stack Identification Code	Annual Emissions				
		Emission Factor	Emission Factor Units	Operating Rate	Operating Units	Annual Emissions, tpy
C	TAH	118	lbs CO2e/ MM Btu	10,950	MMBtu	648.0
Plant	Heaters	118	lbs CO2e/ MM Btu	679,561	MMBtu	40,217.4

Appendix B - Facility Comments for Draft Permit

COMMENTS ON THE DRAFT PERMIT

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
1. Page 4, §1.3, Table 1.1. entry for Process C Control Equipment	None (except source CTZ (5.75 MMBtu/hr dryer) has low-NOx/CO burners)	None (except source CTZ (5.75 MMBtu/hr dryer) has low-NOx~~/CO~~ burners)	This unit has low-NOx burners but the burners are not also low CO.
2. Page 6, §2.6, last sentence	Land Application Permit No. LA-000039-02 regulates odor control for remotely located wastewater treatment farms operated by BAF. Compliance with requirements of the current land application permit pertaining to odors will be deemed compliance with the odor rules of IDAPA 58.01.01.322 as they apply to remotely located wastewater treatment farms.	Please delete this statement.	BAF requested that this statement be added to its original Tier I Operating Permit for Blackfoot back in 2002. However, on May 31, 2011 in *Summit Petroleum Corporation vs. EPA* (Consolidated Case Nos. 09-4348 & 10-4572), the U.S. Court of Appeals, Sixth Circuit, ruled that “adjacent properties” must be located on contiguous surface sites. Accordingly the farm is a separate stationary source for air permitting purposes.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
3. Page 9, §2.24	The permittee shall comply with the applicable requirements of 40 CFR 60, Subpart A – General Provisions in accordance with 40 CFR 60.1	Please move this permit condition, including Table 2.2, to Section 5 of the permit. Alternately, please add language as follows: The permittee shall comply with the applicable requirements of 40 CFR 60, Subpart A – General Provisions in accordance with 40 CFR 60.1 **whenever the facility burns fuel oil in Boilers 1 and/or 2.**	These are boiler-specific conditions, not Facility-Wide ones. To put these requirements in the section for "FACILITY-WIDE CONDITIONS" without denoting that they apply only to Boilers 1 and 2 is very confusing. NSPS applies directly to Boiler 2. NSPS applies to Boiler 1 via Permit Conditions 5.25.1 and 5.25.2. For both Boiler 1 and Boiler 2, these NSPS operating provisions apply only when combusting fuel oil.
4. Table 2.2, Second Row, 4th Bullet	Records shall be maintained of the occurrence and duration of any startup, shutdown or malfunction; any malfunction of the air pollution control equipment; or any periods during which a CMS or monitoring device is inoperative.	Records shall be maintained of the occurrence and duration of any startup, shutdown or malfunction; any malfunction of the air pollution control equipment **during periods when its use is required**; or any periods during which a CMS or monitoring device **is required to be used, but** is inoperative.	Some air pollution control equipment and some CMS and monitoring devices are required to be used only when fuel oil is combusted in boilers 1 & 2. The requested language makes it clear that records of malfunction or inoperability are not required when the equipment itself is not required to be used.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
5. Page 12; §2.32	Documents include, but are not limited to: • Standards of Performance for New Stationary Sources (NSPS), 40 CFR Part 60	Add the following citations to the bullet points lists • National Emission Standards for Hazardous Air Pollutants, 40 CFR Part 61 • National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63	Portions of 40 CFR 61 and 40 CFR 63 are applicable to the Blackfoot Facility in addition to 40 CFR 60. For consistency and completeness, these Parts should be referenced in their entireties as well.
6. Page 13; §3.1; Table 3.1; "Emissions Control(s)" entry for stack CTZ	Low-NOX/CO burner	Low-NOX~~/CO~~ burner	This unit has low-NOx burners but the burners are not also low CO.
7. Page 15; §4.5.1	The permittee shall calculate and record estimated total PM10, SO2, NOX, CO, VOC, **and Pb** emissions…	Please change to read as follows: The permittee shall calculate and record estimated total PM10, SO2, NOX, CO, and VOC emissions…	The FEC permit doesn't include an emissions limit for lead. Accordingly, it is unnecessary to calculate lead emissions on a monthly basis.
8. Page 15; §4.5.3	The permittee shall calculate rolling 12-month total estimated emissions of PM10, SO2, NOX, CO, VOC, **and Pb** for each calendar month. Emissions totals shall be available within 30 days of the end of a month. The permittee shall total PM10, SO2, NOX, CO, VOC, **and Pb** emissions…	Please change to read as follows: The permittee shall calculate rolling 12-month total estimated emissions of PM10, SO2, NOX, CO, and VOC for each calendar month. Emissions totals shall be available within 30 days of the end of a month. The permittee shall total PM10, SO2, NOX, CO, and VOC emissions…	The FEC permit doesn't include an emissions limit for lead. Accordingly, it is unnecessary to calculate lead emissions on a rolling 12-month basis.
9. Page 17; §4.9.2	… the permittee's renewal application for this permit must include …	… the permittee's renewal application for ~~this~~ the FEC portions of Permit to Construct No. P-2009.0043 must include …	Editorial correction.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
10. Page 17; §4.10.3	… all other provisions of this permit shall remain in effect …	… all other provisions of Permit to Construct No. P-2009.0043 shall remain in effect …	Editorial correction.
11. Page 19, §5.3, Paragraph 1	Emissions of particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), sulfur dioxide (SO2), oxides of nitrogen (NOX), and carbon monoxide (CO) from the exhaust stacks of Boilers 1, 2, and 3 shall not exceed the values listed in Table 3.3.	Emissions of particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), sulfur dioxide (SO2), oxides of nitrogen (NOX), and carbon monoxide (CO) from the exhaust stacks of Boilers 1, 2, and 3 shall not exceed the values listed in **Table 5.3**.	Editorial correction.
12. Page 19, §5.3, Table 3.3	Table title: "**Table 3.3 BOILER CRITERIA EMISSION LIMITS**"	Change table number to Table **5.3**	Editorial correction.
13. Page 21, §5.17.3	When Boiler 2 combusts natural gas, wet scrubbing of the Boiler 2 exhaust is not required.	Please re-combine this requirement into Permit Condition 5.17.2	Permit Conditions 5.17.1 and 5.17.2 were intended to mirror each other, one applying to Boiler 1 and the other to Boiler 2. This request restores that mirroring and reduces opportunity for confusion. (Please see language in §3.5.1 and §3.5.2 of PTC No. P-050301.)

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
14. Page 21	Missing Permit Condition	Please insert new Permit Condition 5.17.3 as follows: 5.17.3 When Boiler 1 combusts distillate or residual oil, Boiler 1 shall exhaust through the stack that serves the scrubber. When Boiler 1 combusts natural gas, Boiler 1 may exhaust through its own stack.	Please refer to §3.13.3 and §3.13.4 of Tier I permit No. TI -060315, issued 11/20/2007. That Tier I permit fixed an issue in underlying PTC No. P-050301. The underlying PTC left this condition out. This condition, relating to Boiler 1, was intended to precede and mirror §3.5.3 in the original PTC (No. P-050301).
15. Page 21, §5.17.5	When Boiler 2 combusts distillate or residual oil, Boiler 2 shall exhaust through the stack that serves Boiler 1. When Boiler 2 combusts natural gas, Boiler 2 may exhaust through its own stack.	Please renumber to Permit Condition 5.17.5 and change to read as follows: 5.17.5 When Boiler 2 combusts distillate or residual oil, Boiler 2 shall exhaust through the stack that serves ~~Boiler 1~~**the scrubber**. When Boiler 2 combusts natural gas, Boiler 2 may exhaust through its own stack.	Again, the language in this Permit Condition and the one requested to be inserted, immediately above, are intended to mirror each other, one applying to Boiler 1 and the other to Boiler 2. They are intended to say that when burning oil, the exhaust from either boiler must go through the scrubber, but when burning gas, the scrubber is not required.
16. Page 23, §5.21.6	In accordance with 40 CFR 60.44c(g), the owner or operator of an affected facility shall use all valid SO2 emissions data…	In accordance with 40 CFR 60.44c(~~g~~**J**), the owner or operator of an affected facility shall use all valid SO2 emissions data…	Copy error. The section relating to SO2 emissions is 60.44c(j).

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
17. Page 24, §5.26	At least once every five years a PM performance test shall be conducted on the stack of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the PM emission limit in Permit Condition 2.15. Each boiler shall be tested…	At least once every five years a PM performance test shall be conducted on the stack of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the PM emission limit in Permit Condition 2.15. **The permittee is not required to fire on No. 6 fuel oil solely for the purpose of conducting this PM performance test.** Each boiler shall be tested…	BAF recognizes that the language of this requirement came from the PTC. However, it does not make sense to increase emissions by burning #6 oil solely for the purpose of completing the PM performance test.
18. Page 25, §5.28	Within 60 days of achieving the maximum production rate of Boiler 1 and Boiler 2 when firing No.6 fuel oil, but not later than 180 days after issuance of this permit, and at least once every five years thereafter, performance tests shall be conducted to measure NO_x emissions from the stacks of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the pound per hour NO_x emission limits in Permit Condition 5.4. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less than once every five years.	Within 60 days of achieving the maximum production rate of Boiler 1 and Boiler 2 when firing No.6 fuel oil, but not later than 180 days after issuance of this permit, and at least once every five years thereafter, performance tests shall be conducted to measure NO_x emissions from the stacks of Boiler 1 and Boiler 2, when firing No.6 fuel oil, to demonstrate compliance with the pound per hour NO_x emission limits in Permit Condition 5.4. Each boiler shall be tested while operating alone and each may be tested on a different date so long as each boiler is tested no less than once every five years. **The permittee is not required to fire on No. 6 fuel oil solely for the purpose of conducting this PM performance test.**	BAF recognizes that the language of this requirement came from the PTC. However, it does not make sense to increase emissions by burning #6 oil solely for the purpose of completing the PM performance test.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
19. Page 30, §6.2 and Page 32, §7.2	6.2 The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity…	Duplicates Facility-Wide Condition 2.7.	We note the permit writer has eliminated some redundancy in the boiler section when a condition was already stated as a Facility-Wide condition? We also note this condition was eliminated from Process C requirements. Do we need this statement repeated in Sections 6 and 7? Tables 6.2 and 7.2 could merely point to Permit Condition 2.7.
20. NA	NA	Incorporate applicable provisions of the Boiler MACT rule (40 CFR 63 Subpart JJJJ). However, as with §5.26 and §5.28, above, please state: **The permittee is not required to fire on fuel oil solely for the purpose of completing the WORK PRACTICE STANDARDS of 40 CFR 60, Subpart JJJJJJ.**	Boiler MACT rules are applicable requirements and need to be included in a facility-wide Tier I permit. However, BAF is not currently burning fuel oil and does not intend to in the foreseeable future. The Work Practice Standards of Subpart JJJJJJ should kick in if and when BAF elects to burn fuel oil.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
21. Page 33, §8.1; Page 34. §8.2	Modifications and changes to Process C that are subject to PTC requirements but for which a PTC has not previously been issued are listed below: … Issuance of the January 20, 2011 Permit to Construct meets the requirement to obtain a PTC for these modifications. … The Permit to Construct issued on January 20, 2011 authorizes the above-listed modifications and changes as being covered by PTCs.	~~Modifications and changes to Process C that are subject to PTC requirements but for which a PTC has not previously been issued are listed below:~~ **Please also delete the bullet list that follows this statement** ~~…~~ ~~Issuance of the January 20, 2011 Permit to Construct meets the requirement to obtain a PTC for these modifications.~~ … ~~The Permit to Construct issued on January 20, 2011 authorizes the above-listed modifications and changes as being covered by PTCs.~~	This language reflects one-time compliance requirements that are now completed. Because they do not apply on an on-going basis, they are superfluous for Tier I permitting.
22. Page 33, §8.2	Except the burners associated with source CTZ are Low-NOX/CO burner	None (except source CTZ (5.75 MMBtu/hr dryer) has low-NOx~~/CO~~ burners)	This unit has low-NOx burners but the burners are not also low CO. The proposed text also mimics the proposed language that would be used elsewhere for this control equipment.
23. Page 41, §11.1, Table 11.1	none	Add the following to the list of insignificant activities: Natural gas-fired space heating units not listed in §9.2, above (30)	The space heaters identified in the suggested addition are also insignificant activities and should be identified as such in the permit.
24. Page 42, §12	"Part 63 National Emission Standards for Hazardous Air Pollutants"	Change to: "Part 63 National Emission Standards for Hazardous Air Pollutants *except Subpart ZZZZ*"	The Blackfoot Facility has an existing RICE that is subject to Supart ZZZZ.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
25. Page 42, §12, “reason code” j	the facility is not a major source of HAP emissions	Change to: “the facility is not subject any Part 63 NESHAP other than Subpart ZZZZ.	The Blackfoot Facility has an existing RICE that is subject to Supart ZZZZ. No other Part 63 NESHAPs are applicable.
26. Appendices A, C, and D	various	Use emissions factors presented in Appendix A of the Draft Statement of Basis	The emissions factors in the tables in these Appendices have not been updated to include the modified emissions factors developed from BAF's 2011 voluntary source testing program. The emission factors in Appendix A of the draft Statement of Basis do include the modified emissions factors, and the permit Appendices should be updated to match those presented in the Statement of Basis.

1. COMMENTS ON STATEMENT OF BASIS

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
27. General	Various	Please carry the requested changes from the permit over to their respective references in the Statement of Basis (SOB).	Much of the language in the permit is also contained in the Statement of Basis (SOB). This general request will ensure that changes requested in the permit will be carried over to their respective counterparts in the SOB. This, in turn, will reduce the potential for confusion in the future.
28. General	Various	Please use consistent formatting in the various subparts of Section 6 of the SOB. The formatting should make clear that for each primary permit condition, the MRRR conditions that follow it relate back to that primary permit condition. Preferred formatting would be as in Subsection 6.1, except to indent all the MRRR conditions. Alternately, you might bold all the primary permit conditions and leave the MRRR conditions un-bolded.	The formatting is not currently consistent in the various parts of Section 6. Subsection 6.1 uses bolded headers . Subsection 6.3 doesn't bold the headers. The changes in formatting become confusing.
29. Page 7, Table 5.1, Line relating to Emissions Unit CTZ	Low-NOX/CO burner	Low-NOX~~/CO~~ burner	The burners are Low-NOx, but not low-CO.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
30. Page 8, §5.1	"BAF's Blackfoot facilities include a food drying and dehydrating plant and a co-located research and development laboratory related to vegetable dehydrating and product development. The Blackfoot Plant produces a variety of dehydrated food products for both internal use and for customers. BAF uses a variety of dehydration technologies to produce products to meet customer specifications. Three boilers provide process steam for the Blackfoot Plant from the combustion of fuel."	Delete this language.	Deleted text duplicates information in Section 3.1
31. Pages 9 and 10, §5.4, 5.5, 5.6	"… decomposition of sulfites …"	Change to: "conversion of sulfites"	The release of SO2 from sulfites is not due to decomposition. There is no change in valence of sulfur. Sulfites are salts of SO2.
32. Page 10, §5.6, Table 5.6 discussion of control devices	"Except the burners associated with source CTZ are Low-NO_X/CO burner"	Change to: "Except the burners associated with source CTZ are Low-NOx burners"	The CTZ burners are not low CO burners.
33. Page 11, §5.8, Table 5.8	NA	Add the following new entry on the table: <table><tr><td>Natural gas-fired space heating units not listed in Section 5.7, above</td><td>(30)</td></tr></table>	The space heaters identified in the suggested addition are also insignificant activities and should be identified as such in the permit.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
34. Page 12, §5.9 List of Non-applicable Requirements of 40 CFR	"Part 63 National Emission Standards for Hazardous Air Pollutants"	Change to: "Part 63 National Emission Standards for Hazardous Air Pollutants *except Subparts JJJJ and ZZZZ*"	Boilers at the Blackfoot Facility are subject Subpart JJJJ when combusting oil. The Blackfoot Facility also has an existing RICE that is subject to Subpart ZZZZ.
35. Page 12, §5.9, reason code "j"	"the facility is not a major source of HAP emissions"	Change to: "the facility is not subject any Part 63 NESHAP other than Subparts JJJJ and ZZZZ.	Boilers at the Blackfoot Facility are subject Subpart JJJJ when combusting oil. The Blackfoot Facility also has an existing RICE that is subject to Subpart ZZZZ. No other Part 63 NESHAPs are applicable.
36. Pages 15-16, §5.10,	All text between the end of Table 5.9 and the start of §6	Replace the referenced text in its entirety with the replacement text for this section presented below this table.	The replacement text provides more accurate and complete discussions of the development and use of emission factors.
37. Page 17, last bullet	• It was determined that Land Application Permit No. LA-000039-02 regulates odor control for remotely located wastewater treatment farms operated by BAF. Compliance with requirements of the current land application permit pertaining to odors will be deemed compliance with the odor rules of IDAPA 58.01.01.322 as they apply to remotely located wastewater treatment farms.	Please remove this statement.	Please see requested change for Permit Condition 2.6 in the 1, of this document pertaining to COMMENTS ON THE DRAFT PERMIT.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
38. Page 18, discussion of Permit Condition 2.15	Permit Condition 2.15 – Fuel-Burning Equipment PM Standards The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid, 0.050 gr/dscf of effluent gas corrected to 8% oxygen by volume for coal, and 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume for wood products.	Permit Condition 2.15 and 2.16 – Fuel-Burning Equipment The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid, 0.050 gr/dscf of effluent gas corrected to 8% oxygen by volume for coa~~l, and 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume for wood products.~~ For fuel-burning equipment in operation prior to October 1, 1979, or with a maximum rated input of 10 MMBtu/hr or less, the permittee shall not discharge to the atmosphere PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas; and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuel.	The suggested language mirrors the language of the permit.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
39. Page 18, discussion of Permit Condition 2.17	Permit Condition 2.17 - Sulfur Content Limits	Permit Condition 2.17 and 2.18 - Sulfur Content Also add the language of 2.18: to the bullet list: • The permittee shall not sell, distribute, use, or make available for use any residual fuel oil containing more than one and three-fourths percentage (1.75%) sulfur by weight.	Suggested change mirrors the headings in the permit and the format for presenting permit language in the SOB.
40. Page 18, discussion of Permit Condition 2.18	MRRR - (Permit Condition 2.18)	MRRR - (Permit Condition 2.19)	Mismatch between Permit and SOB.
41. Page 20, discussion of Permit Condition 2.25	Permit Condition 2.25 - Monitoring and Recordkeeping	Permit Conditions 2.25 and 2.26 - Monitoring and Recordkeeping Also add the language of 2.26: *2.26 During periods when a process or activity is shut down or not operating, monitoring requirements for that process are suspended. In these circumstances, monitoring reports submitted shall note that the process was shut down or not operating, and shall provide, as applicable, the dates of shutdown and start-up.* *[IDAPA 58.01.01.322.06, 07, 5/1/94; IDAPA 58.01.01.322.08, 4/5/00]*	Permit condition omitted from discussion in SOB.

REFERENCE	EXISTING LANGUAGE	REQUESTED CHANGE	JUSTIFICATION
42. Page 20, §6.1, relating to MRRR (Permit Conditions 2.29 and 2.30)	"The permittee shall submit compliance test report(s) to DEQ following performance testing."	Limit this to required performance testing as follows: "The permittee shall submit compliance test report(s) to DEQ following ***required*** performance testing."	Voluntary testing is not subject to this MRRR requirement.
43. Page 24, §6.4	NA	Add permit condition 5.28 to the MRRR for Permit Condition 5.3	The NOx performance test is part of compliance demonstration provisions for Permit Condition 5.3

44. <u>§5.10 Replacement Text</u>

The following text should replace all of the text in §5.10 between the end of Table 5.9 and the start of §6 (i.e., commencing with *"The emission estimates are explained in the emissions inventory appendix spreadsheets."* and ending with *""Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors" for details."*)

The emission estimates are explained in the emissions inventory appendix spreadsheets.

The PM_{10}, SO_2, CO, and NO_x estimates for the boilers are based on enforceable limits from the 9/16/05 PTC. The VOC estimates were based on AP-42 for the highest emitting fuel.

Emissions estimates for process equipment, including process burners, are based on voluntary source tests done by the facility at various times since 1995. This testing has been done because of the lack of standard emission factors for BAF processes, many of which are proprietary or unique. Development and use of emission factors has been documented in previous permitting actions for the facility through the issuance of Permit to Construct No. 2009.0043, issued January 20, 2011. SO_2 emission factors for natural gas combustion in process dryers and space heaters are derived from AP-42 and assume 0.8 grains of sulfur per 100 scf of gas combusted. SO_2 emissions associated with conversion of sulfite are based on BAF experience with sulfite conversion in drying processes.

To estimate annual emissions the emission factors are generally used assuming that equipment operates 8760 hours per year at full capacity, with the exception that space heaters are assumed to operate 4380 hours years (50% duty). Plant space heaters are designed and sized for comfort space heating during cold weather periods. During warm weather periods the heaters are not needed and do not operate. In fact were the space heaters to operate when they are not needed for space heating, working conditions inside the plant would become unbearably hot. Accordingly, the assumption that space heaters operate at no more than 50 per cent of firing capacity on an annual basis is a practical and effective limit on operations, as higher operating rates are an operating condition that is contrary to design and that would be detected and corrected.

The only changes in emission factors from those used in Permit to Construct No. 2009.0043 involve the following stacks:

Process	Stack	Pollutants with Revised Emission Factors
A	DUV	PM-10
C	CHX	PM-10; CO; NOx
C	CHY	PM-10; CO; NOx
C	CHZ	PM-10; CO; NOx
C	TEE	PM-10; CO; NOx
C	TEM	PM-10; CO; NOx
C	CBB	PM-10
C	CTQ	PM-10
C	CTR	PM-10
C	CTS	PM-10
C	CTT	PM-10
C	CNV	PM-10
C	CNW	PM-10
C	CTU	PM-10
C	CTZ	PM-10

The changes in emission factors listed above are based on additional voluntary source testing conducted by BAF in November 2011. This testing program and the basis for changes is documented in BAF's report to DEQ, "*Review of Results of November 2011 Source Testing at Blackfoot Facility of Basic American Foods and Development of Revised Emission Factors*", (Coal Creek Environmental Associates, April 2012), which was submitted to DEQ in accordance with provision 3.4.2 of Permit to Construct No. 2009.0043, issued January 20, 2011.

Response to Facility Draft Comments

Comment No. 1

Wording has been changed in Table 1.1 to show low-NO_x burner.

Comment No. 2

The Land Applcation permit requirement was removed.

Comment No. 3

Change was made as requested.

Comment No. 4

Change was made as requested.

Comment No. 5

Done.

Comment No. 6

Done.

Comment No. 7

The permit requirement is a direct quote of the underlying PTC requirement. The PTC needs to be modified first.

Comment No. 8

See response to Comment No. 7.

Comment No. 9

The change has been made because it is clear that the renewal applies to the FEC permit portions because renewal of the remainder of the permit is not applicable.

Comment No. 10

The change has been made because this condition was incorporated from the PTC with that permit number, so this makes it more clear that "this permit" refers to the PTC that was issued with that permit condition.

Comment No. 11

Done. This was an editorial correction.

Comment No. 12

Done. This was an editorial correction.

Comment No. 13

Done. This was a copy error.

Comment No. 14

Done. This was negotiated in the previous permit.

Comment No. 15

Done. This was negotiated in the previous permit.

Comment No. 16

Correction made. Copy error.

Comment No. 17

The permit requirement is a direct quote of the underlying PTC requirement. The PTC needs to be modified first.

Comment No. 18

The permit requirement is a direct quote of the underlying PTC requirement. The PTC needs to be modified first.

Comment No. 19

The changes were made to eliminate redundancy.

Comment No. 20

Gas fired boilers are not subject to the Boiler Mact The definition of gas fired boiler from Subpart JJJJJJ is, "Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." The boilers do not qualify as gas-fired boilers, so the regulation applies. There is no exemption for boilers that are not currently being fired on oil but are designed and permitted to do so. Therefore, the regulation applies as written, and it would be incorrect to modify the permit to indicate otherwise.

Comment No. 21

This change was made because a PTC has been obtained, so this part of the applicable condition has been finished.

Comment No. 22

The correction was made.

Comment No. 23

Done.

Comment No. 24

Change has been made. The existing RICE is addressed separately.

Comment No. 25

The change has been made.

Comment No. 26

The Emission Factor appendices are part of Permit to Construct No. 2009.0043 dated January 20, 2011. Because these factors are not referenced in the PTC permit as a part of a permit condition, the factors can be updated as requested.

Comment No. 27

This has been done.

Comment No. 28

The MRRR references have been bolded.

Comment No. 29

The change has been made.

Comment No. 30

Done.

Comment No. 31

The changes have been made.

Comment No. 32

The change has been made

Comment No. 33

The addition has been made.

Comment No. 34

40 CFR 63 ZZZZ is for generators. 40 CFR 63 JJJJ is for Paper and Other Web Coating. The boilers are subject to the area source boiler MACT, which is 40 CFR 63 Subpart JJJJJJ, when combusting oil.

Comment No. 35

Done. Also changed in permit.

Comment No. 36

Done.

Comment No. 37

Done.

Comment No. 38

This was corrected to match the permit.

Comment No. 39

This was corrected to match the permit.

Comment No. 40

This was corrected to match the permit.

Comment No. 41

This was corrected to match the permit.

Comment No. 42

Done.

Comment No. 43

Done.