Statement of Basis

Permit to Construct No. P-2009.0091
Project ID 61970

Gavilon Grain, LLC
Burley, Idaho

Facility ID 031-00038

Final

June 29, 2018
Morrie Lewis
Permit Writer

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

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
Btu	British thermal units
CAA	Clean Air Act
CAS No.	Chemical Abstracts Service registry number
CEMS	continuous emission monitoring systems
CFR	Code of Federal Regulations
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
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	pounds
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
PAH	polycyclic aromatic hydrocarbons
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
POM	polycyclic organic matter
ppm	parts per million
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*
scf	standard cubic feet
SIL	significant impact levels
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
TAP	toxic air pollutants
U.S.C.	United States Code
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

Gavilon Grain, LLC in Burley, Idaho manufactures animal feed. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. Processes include use of receiving pits, grain distribution legs, hammermills, conveyors, screw augers, storage bins, and storage piles.

Grain is received mostly by railcar, although some arrives by truck. The grain is unloaded into below-grade pits and then treated with edible mineral oil to control dust during the handling process. From the receiving pits, grain is transported by conveyors to various destinations within the facility. Grinding is done with hammermills, and emissions are controlled by cyclones and baghouses. Processed grain is stored in silos until shipment.

The corn flaking process involves cleaning and scalping corn in the Rotary Grain Cleaner, steaming corn in the steam chamber, rolling corn into flakes in flaking mill rollers, and cooling and drying flakes prior to shipment. A boiler generates steam for the steam chamber.

Permitting History

The following information was derived from a review of the permit files available to DEQ. Permitting action status is noted as active and in effect (A) or superseded (S).

June 29, 2018	P-2009.0091 Project 61970, revised PTC a corn steam flaking line. (A)
April 13, 2017	P-2009.0091 Project 61832, revision to change pressure drop monitoring range for Cyclones 1 and 2. (A, but will become S upon issuance of this permit)
March 15, 2016	Project 61675, DEQ determined that the addition of a portable transload conveyor system receiving throughput of 61,200 T/yr, storage piles limited to 0.75 acres and 84 days of exposure per year, and truck loadout throughput of 61,200 T/yr was exempt from air quality permitting. (A)
July 12, 2012	P-2009.0091 Project 61051, revision to remove the requirement to apply mineral oil to high-moisture grain. (S)
May 28, 2010	P-2009.0091, initial PTC five hammermills and to increase throughput to 12 million bushels per year (MMbu/yr). (S)
September 26, 2003	DEQ determined that the facility's grain elevator with a new elevator leg and a throughput of 10 MMbu/yr was exempt from air quality permitting. (A)
April 29, 1997	DEQ determined that the facility's grain elevator with a throughput of 8 MMbu/yr was categorically exempt from air quality permitting in accordance with IDAPA 16.01.01.223.03.i, Rules for the Control of Air Pollution in Idaho (Rules). (S)

Application Scope

This PTC is for a minor modification at an existing minor facility.

The applicant has proposed to:

- Install and operate a corn steam flaking product line; including flaker, cooler, boiler, and product handling and storage equipment.
- Replace an existing overhead drag fill conveyor with a new drag conveyor of equivalent throughput capacity (25,000 bushels/hr), tied to existing legs (bucket elevators) for filling existing bins 4 and 5.
- Increase daily operation of existing hammermills from 12 to 13 hours per day.

Application Chronology

December 11, 2017	DEQ received an application and application fee.
December 18, 2017 – January 2, 2018	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
January 10, 2018	DEQ determined that the application was incomplete.
February 9, 2018	DEQ received supplemental information from the applicant.
March 9, 2018	DEQ determined that the application was complete.
April 27, 2018	DEQ made available the draft permit and statement of basis for peer and regional office review.
May 2, 2018	DEQ made available the draft permit and statement of basis for applicant review.
May 8, 2018	DEQ received the permit processing fee.
May 24 – June 25, 2018	DEQ provided a public comment period on the proposed action.
June 29, 2018	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source	Control Equipment
Grain Processing **1.** Grain Receiving **2.** Grain Handling **3.** Grain Storage **4.** Grain Cleaning **5.** Grain Milling (Hammermill Nos. 1 to 5) **6.** Grain Shipping **7.** Corn Flaking Mill Rollers and Cooler Dryer (w/ Cyclone) **8.** Flake Storage Pile Handling and Flake Shipping	<u>Grain Receiving</u> Choke-feed, Shroud <u>Grain Handling</u> Enclosure, Mineral Oil Application <u>Grain Storage</u> Mineral Oil Application <u>Grain Cleaning</u> Enclosed and Mineral Oil <u>Grain Milling</u> Mineral Oil Application Baghouse Nos. 1, 2, & 3 for Hammermill Nos. 1, 2, & 3 Manufacturer: Air Lanco Model: 49AVS10 Manufacture date: 2007 Control Efficiency: 99% Cyclone Nos. 1 & 2 for Hammermill Nos. 4 & 5 Manufacturer: Bliss Industries Model: LE 30 Manufacture date: 2006 Control Efficiency: 50% <u>Grain Shipping (excluding transloaded material)</u> Mineral Oil Application <u>Corn Flaking Mill Rollers and Cooler Dryer</u> None <u>Flake Storage Pile Handling and Flake Shipping</u> Partial Enclosure
<u>Boiler</u> Operational capacity: 13,800 lb steam/hr Manufacturer: Superior Boiler Works, Inc. Model: Apache 8-5-2000-S150 Manufacture date: 2018 Maximum capacity: 16.737 MMBtu/hr Fuel: natural gas Fuel consumption: 25,000 scf/hr	None

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit (PTE) 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 hours 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 emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for the corn steam flaking project (see Appendix A). Estimates of criteria pollutant, hazardous air pollutant (HAP), and toxic air pollutant (TAP) PTE were based on emission factors from AP-42;[1] production equipment capacities and throughput limits (Permit Conditions 2.9–2.10); operational limits of 12 hours per day for the hammermills, truck drops, and loadouts (Permit Conditions 2.11 and 2.21); stack test data from a cooler cyclone of similar design;[2] manufacturer design specifications for the boiler burner;[3] and relevant site-specific and process-specific information.[4] Although an AP-42 emission factor was available for flaker cyclones, emissions from the Cyclone were estimated based on test data from another corn steam flaking process with a similar cyclone design and similar stack conditions.[2]

Uncontrolled PTE

Using the definition of PTE, uncontrolled PTE is then 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 hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled PTE is used to determine if a facility is a "synthetic minor" source of emissions. Synthetic minor sources are facilities that have an uncontrolled PTE for regulated air pollutants or HAP above an applicable major source threshold without permit limits.

The following table presents the uncontrolled PTE for regulated air pollutants as submitted by the applicant and verified by DEQ staff. See Appendix A and the statement of basis from the prior permitting action[5] for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit.

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1 Compilation of Air Pollutant Emission Factors, AP-42, Volume I, Fifth Edition (AP-42), Section 9.9.1 – Grain Elevator and Processes, Section 1.4 – Natural Gas Combustion, and Section 13.2.4 – Aggregate Handling and Storage Piles, Office of Air Quality Planning and Standards Office of Air and Radiation (OAQPS), EPA, May 2003, July 1998, and November 2006 (resp.).

2 Estimated cooler cyclone emission rates from "Determination of Emission Factors for Steam Flaking of Corn at a Commercial Feedmill," presented at American Society of Agricultural and Biological Engineers (ASABE) annual meeting, Purswell, Faulkner, and Spencer, July 2012. (2017AAG2291)

3 Criteria pollutant estimated boiler emission rates for HDS & HDSX burners firing natural gas, Webster Combustion, September 2016. (2017AAG2291)

4 Enclosure and mineral oil control efficiencies from "Grain Elevator and Grain Processing Air Quality Permits and Reports," Outreach and Extension of University of Missouri-Columbia, Downs and Pfost, 1993; percent throughput of foreign material estimated from "2016-2017 Corn Harvest Quality Report," U.S. Grains Council, 2017; and percent moisture content in final product estimated from "Steam Flaking - Focus on Conditioning," Roskamp Champion, 1999.

5 Statements of basis for PTC No. P-2009.0091, issued May 28, 2010 and PTC exemption Project 61675, issued March 15, 2016. (2009AAG5977, 2016AAG361)

Table 2 UNCONTROLLED EMISSIONS FOR REGULATED AIR POLLUTANTS

Emissions Unit	PM_{10}	SO_2	NO_X	CO	VOC	HAP	Lead
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Grain Receiving	0.88	0.00	0.00	0.00	0.00	0.00	0.00
Grain Handling	11.90	0.00	0.00	0.00	0.00	0.00	0.00
Grain Storage	2.21	0.00	0.00	0.00	0.00	0.00	0.00
Grain Milling	5.25	0.00	0.00	0.00	0.00	0.00	0.00
Grain Shipping	0.28	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Receiving	2.63	0.00	0.00	0.00	0.00	0.00	0.00
Transload Materials Internal Handling	35.74	0.00	0.00	0.00	0.00	0.00	0.00
Transload Truck Loadout	0.84	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Activity	0.55	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Wind Erosion	0.42	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Shipping from Storage Piles	1.16	0.00	0.00	0.00	0.00	0.00	0.00
Grain and Flake Handling	3.91	0.00	0.00	0.00	0.00	0.00	0.00
Grain Cleaning	21.06	0.00	0.00	0.00	0.00	0.00	0.00
Flake Storage Pile Handling & Shipping	0.18	0.00	0.00	0.00	0.00	0.00	0.00
Boiler	0.35	0.07	7.04	2.71	0.59	0.83	3.7E-05
Totals	**87.36**	**0.07**	**7.04**	**2.71**	**0.59**	**0.83**	**3.7E-05**

Pre-Project Potential to Emit

Pre-project PTE is used to establish the change in emissions at a facility as a result of this project. The following table presents the pre-project potential to emit for regulated air pollutants as submitted by the applicant and verified by DEQ staff. See Appendix A and the statement of basis from the prior permitting action[5] for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit.

Table 3 PRE-PROJECT PTE FOR REGULATED AIR POLLUTANTS

	PM_{10}		SO_2		NO_x		CO		VOC		HAP		Lead	
	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)	lb/hr(a)	T/yr(b)
Grain Receiving	0.28	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Handling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Storage	1.13	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Milling	1.90	4.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Shipping	0.15	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Receiving	0.30	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Materials Internal Handling	8.16	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Truck Loadout	0.19	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Activity	0.13	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Wind Erosion	0.09	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Shipping from Storage Piles	0.26	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pre-Project Totals	**12.59**	**5.81**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Post-Project PTE

Post-project PTE is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post-project PTE includes all permit limits resulting from this project. The following table presents the post-project PTE for regulated air pollutants as submitted by the applicant and verified by DEQ staff. See Appendix A and the statement of basis from the prior permitting action[5] for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. The permittee has removed the North Green Train Pit identified in prior applications (GR1), and this emission source is no longer included in the post-project emission inventory.

Table 4 POST-PROJECT PTE FOR REGULATED AIR POLLUTANTS

	PM_{10}		SO_2		NO_x		CO		VOC		HAP		Lead	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Grain Receiving	0.28	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Handling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Storage	1.13	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Milling	1.90	4.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Shipping	0.15	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Receiving	0.30	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Materials Internal Handling	8.16	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Truck Loadout	0.19	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Activity	0.13	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Storage Piles Wind Erosion	0.09	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transload Feed Ingredient Shipping from Storage Piles	0.26	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain and Flake Handling	0.10	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain Cleaning	0.49	2.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Flake Storage Pile Handling & Shipping	0.02	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boiler	0.08	0.35	0.02	0.07	1.61	7.04	0.62	2.71	0.13	0.59	0.19	0.83	8.4E-06	3.7E-05
Post-Project Totals	**13.28**	**8.83**	**0.02**	**0.07**	**1.61**	**7.04**	**0.62**	**2.71**	**0.13**	**0.59**	**0.19**	**0.83**	**8.4E-06**	**3.7E-05**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 5 CHANGES IN PTE FOR REGULATED AIR POLLUTANTS

Emissions Unit	PM_{10}		SO_2		NO_x		CO		VOC		HAP		Lead	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Pre-Project PTE	12.59	5.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post-Project PTE	13.28	8.83	0.02	0.07	1.61	7.04	0.62	2.71	0.13	0.59	0.19	0.83	8.4E-06	3.7E-05
Change in PTE	**0.69**	**3.02**	**0.02**	**0.07**	**1.61**	**7.04**	**0.62**	**2.71**	**0.13**	**0.59**	**0.19**	**0.83**	**8.4E-06**	**3.7E-05**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

TAP Emission Increases

A summary of the estimated facility-wide PTE (and emission increases) of non-carcinogenic and carcinogenic TAP is provided in the following table.

Some of the PTE for carcinogenic TAP were exceeded as a result of this project. Therefore, modeling was required for arsenic, cadmium, formaldehyde, and nickel because the corresponding carcinogenic screening emission levels (EL) identified in IDAPA 58.01.01.586 were exceeded.

Table 6 PRE- AND POST- PROJECT POTENTIAL TO EMIT FOR TOXIC AIR POLLUTANTS

Toxic Air Pollutants	Post-Project 24-hour Average Emissions Rates (lb/hr)	Post-Project PTE (T/yr)	Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
2-Methylnaphthalene	4.02E-07	1.76E-06	n/a	No
3-Methylchloranthrene	3.01E-08	1.32E-07	2.50E-06	No
7,12-Dimethylbenz(a)anthracene	2.68E-07	1.17E-06	n/a	No
Acenaphthene	3.01E-08	1.32E-07	n/a	No
Acenaphthylene	3.01E-08	1.32E-07	n/a	No
Anthracene	4.02E-08	1.76E-07	n/a	No
Benzo(a)anthracene	3.01E-08	1.32E-07	n/a	No
Benzene	3.51E-05	1.54E-04	8.00E-04	No
Benzo(a)pyrene	2.01E-08	8.80E-08	2.00E-06	No
Benzo(b)fluoranthene	3.01E-08	1.32E-07	n/a	No
Benzo(g,h,i)perylene	2.01E-08	8.80E-08	n/a	No
Benzo(k)fluoranthene	3.01E-08	1.32E-07	n/a	No
Butane	3.51E-02	1.54E-01	n/a	No
Chrysene	3.01E-08	1.32E-07	n/a	No
Dibenzo(a,h)anthracene	2.01E-08	8.80E-08	n/a	No
Dichlorobenzene	2.01E-05	8.80E-05	20.00	No
Ethane	5.19E-02	2.27E-01	n/a	No
Fluoranthene	5.02E-08	2.20E-07	n/a	No
Fluorene	4.69E-08	2.05E-07	n/a	No
Formaldehyde	1.26E-03	5.50E-03	5.10E-04	**Yes**
n-Hexane	3.01E-02	1.32E-01	12	No
Indeno(1,2,3-cd)pyrene	3.01E-08	1.32E-07	n/a	No
Naphthalene	1.02E-05	4.47E-05	3.33	No
Pentane	4.35E-02	1.91E-01	118.00	No
Phenanathrene	2.85E-07	1.25E-06	n/a	No
Propane	2.68E-02	1.17E-01	n/a	No
Pyrene	8.37E-08	3.67E-07	n/a	No
Toluene	5.69E-05	2.49E-04	25	No
Arsenic compounds	3.35E-06	1.47E-05	1.50E-06	**Yes**
Barium compounds	7.36E-05	3.23E-04	3.30E-02	No
Beryllium compounds	2.01E-07	8.80E-07	2.80E-05	No
Cadmium compounds	1.84E-05	8.06E-05	3.70E-06	**Yes**
Chromium compounds	2.34E-05	1.03E-04	3.30E-02	No
Cobalt compounds	1.41E-06	6.16E-06	3.30E-03	No
Copper compounds	1.42E-05	6.23E-05	1.30E-02	No
Manganese compounds	6.36E-06	2.79E-05	6.70E-02	No
Mercury compounds	4.35E-06	1.91E-05	n/a	No
Molybdenum compounds	1.84E-05	8.06E-05	3.33E-01	No
Nickel compounds	3.51E-05	1.54E-04	2.70E-05	**Yes**
Selenium compounds	4.02E-07	1.76E-06	1.30E-02	No
Vanadium compounds	3.85E-05	1.69E-04	3.00E-03	No
Zinc compounds	4.85E-04	2.13E-03	6.67E-01	No
Mineral Oil Mist	0.00E+00	0.00E+00	3.33E-01	No
Polycyclic aromatic hydrocarbons (exc. 7-PAH)	9.87E-07	4.33E-06	9.10E-05	No
7-PAH group (POM)[a]	8.60E-07	3.77E-06	2.00E-06	No

a) Polycyclic Organic Matter (POM) is considered as one TAP comprised of: benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indeno(1,2,3-cd)pyrene, benzo(a)pyrene. The total is compared to benzo(a)pyrene.

Ambient Air Quality Impact Analyses

As presented in the modeling memorandum in Appendix B, the estimated emission rates of $PM_{2.5}$, PM_{10}, and NO_x criteria pollutants; and arsenic, cadmium, formaldehyde, and nickel HAP/TAP from this project exceeded applicable screening emission levels (EL) and published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline.[6] Refer to the Emissions Inventories section for additional information concerning the emission inventories.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for TAP.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Cassia County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAPs (Hazardous Air Pollutants) Only:

A	=	Use when any one HAP has actual or potential emissions $\geq$ 10 T/yr or if the aggregate of all HAPS (Total HAPs) has actual or potential emissions $\geq$ 25 T/yr.
SM80	=	Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits $\geq$ 8 T/yr of a single HAP or $\geq$ 20 T/yr of THAP.
SM	=	Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.
B	=	Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold
UNK	=	Class is unknown

[6] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

UNK = Class is unknown.

Table 7 REGULATED AIR POLLUTANT FACILITY CLASSIFICATIONS

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	101.99	8.83	**100**	SM
PM_{10}	87.36	8.83	**100**	B
$PM_{2.5}$	66.54	8.83	**100**	B
SO_2	0.07	0.07	**100**	B
NO_x	7.04	7.04	**100**	B
CO	2.71	2.71	**100**	B
VOC	0.59	0.59	**100**	B
HAP (single)	5.50E-03	5.50E-03	**10**	B
HAP (total)	0.83	0.83	**25**	B
Pb	3.7E-05	3.7E-05	**100**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 .... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed corn steam flaking process. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 .... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 .... Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity (Permit Condition 2.4). Compliance with this limit is assured by complying with fuel restrictions (Permit Condition 2.6), and baghouse and cyclone control equipment requirements (Permit Conditions 2.12–2.16).

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676 .... Standards for New Sources

Fuel-burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, is subject to a particulate matter limitation of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This limit was incorporated as Permit Condition 2.5.

Particulate Matter – New Equipment Process Weight Limitations (IDAPA 58.01.01.701)

IDAPA 58.01.01.701 .... Particulate Matter – New Equipment Process Weight Limitations

IDAPA 58.01.01.700 through 703 set PM emission limits for process equipment based on when the piece of equipment commenced operation and the piece of equipment's process weight (PW) in pounds per hour (lb/hr). IDAPA 58.01.01.700.02 allows for a minimum allowable emission rate of 1 lb/hr. Because the proposed new equipment does not exceed 1 lb/hr, compliance is assured with this limitation by complying with grain processing PM_{10} limits (Permit Condition 2.3).

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

IDAPA 58.01.01.301 .... Requirement to Obtain Tier I Operating Permit

Post-project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and VOC, 10 tons per year for any one HAP, or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 .... Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 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 in accordance with 40 CFR 52.21(a)(2), PSD requirements were not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

Because the facility has a natural gas-fired boiler, the following is an NSPS applicability analysis for the proposed equipment:

- 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. DEQ is delegated this Subpart.

40 CFR 60, Subpart Dc .... *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

§ 60.40c .... *Applicability and delegation of authority.*

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

The design heat input capacity for the proposed boiler is rated at 16.737 MMBtu/hr.

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

Combustion research has not been proposed by the applicant.

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

The proposed boiler does not meet Subpart KKKK, AAAA, BBBB, CCCC, J, or Ja applicability, and the boiler has been proposed as a stationary source.

§ 60.41c .... Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor *means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.*

Coal *means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.*

Coal refuse *means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.*

Combined cycle system *means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.*

Combustion research *means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).*

Conventional technology *means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.*

Distillate oil *means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).*

Dry flue gas desulfurization technology *means a SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.*

Duct burner *means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.*

Emerging technology *means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).*

Federally enforceable *means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.*

Fluidized bed combustion technology *means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.*

Fuel pretreatment *means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.*

Heat input *means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).*

Heat transfer medium *means any material that is used to transfer heat from one point to another point.*

Maximum design heat input capacity *means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.*

Natural gas *means:*

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area *means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.*

Oil *means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.*

Potential sulfur dioxide emission rate *means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.*

Process heater *means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.*

Residual oil *means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).*

Steam generating unit *means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.*

Steam generating unit operating day *means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.*

Temporary boiler *means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:*

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology *means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.*

Wet scrubber system *means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.*

Wood *means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.*

This section contains the definitions of this Subpart.

§ 60.42c .... Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

Es = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

Ka = 520 ng/J (1.2 lb/MMBtu);

Kb = 260 ng/J (0.60 lb/MMBtu);

Kc = 215 ng/J (0.50 lb/MMBtu);

Ha = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

Hb = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

Hc = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to SO_2 standards.

§ 60.43c .... Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, 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/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to PM or opacity standards.

§ 60.44c .... *Compliance and performance test methods and procedures for sulfur dioxide.*

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

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §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 the affect facility will be operated, but not later than 180 days after the initial startup of the facility. 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.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c is based on the average percent reduction and 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 percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (Eho) and the 30-day average SO_2 emission rate (Eao). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate Eao when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted Eho (Ehoo) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted Eao (Eaoo). The Ehoo is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_{w}(1 - X_{k})}{X_{k}}$$

Where:

Ehoo = Adjusted Eho, ng/J (lb/MMBtu);

Eho = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

Ew = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0.

Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters Ew or Xk if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

%Ps = Potential SO_2 emission rate, in percent;

%Rg = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%Rf = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) *If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:*

(i) *To compute the %Ps, an adjusted %Rg (%Rgo) is computed from Eaoo from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (Eaio) using the following formula:*

$$\%R_g o = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

%Rgo = Adjusted %Rg, in percent;

Eaoo = Adjusted Eao, ng/J (lb/MMBtu); and

Eaio = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) *To compute Eaio, an adjusted hourly SO_2 inlet rate (Ehio) is used. The Ehio is computed using the following formula:*

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

Ehio = Adjusted Ehi, ng/J (lb/MMBtu);

Ehi = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

Ew = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value Ew for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure Ew if the owner or operator elects to assume Ew = 0; and

Xk = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) *For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §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 §60.46c(d)(2).*

(h) *For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.*

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating %Ps and Eho under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §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 %Ps or Eho pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to SO_2 standards.

§ 60.45c .... Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to PM or opacity standards.

§ 60.46c .... Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 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 owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). 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.

(c) The procedures under §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 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, 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 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a 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) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent 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 Administrator.

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to SO_2 standards.

§ 60.47c .... Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e. , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO_2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section §60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section §60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to PM or opacity standards.

§ 60.48c .... Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

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

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility 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. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the 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 appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, 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/MMBtu), 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) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) 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 coal or oil were 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 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) 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.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), which is not identified in this section as a regulated fuel subject to SO_2, PM, or opacity standards. In accordance with §60.48c(a), the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7. Permit Condition 2.27 includes the requirements of this section.

In accordance with §60.48c(g)(2) or (3), as an alternative to meeting the requirements of (g)(1) of this section, the owner or operator may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to the boiler on either a daily or monthly basis. Permit Condition 2.27 includes the requirements of this section.

In accordance with 40 CFR 60.48c(i), 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. Permit Condition 2.27 includes the requirements of this section.

In accordance with 40 CFR 60.48c(j), the reporting period for any reports required pursuant to this Subpart is each six-month period. Permit Condition 2.27 includes the requirements of this section.

In accordance with 40 CFR 60.48c(a), 40 CFR 60.7, and IDAPA 58.01.01.211, the owner or operator shall submit notification for the boiler of construction, reconstruction, and startup activities.

NESHAP Applicability (40 CFR 61)

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

MACT/GACT Applicability (40 CFR 63)

The facility is not subject to any MACT standards in 40 CFR Part 63.

Because the facility has a natural gas-fired boiler, the following is an NSPS applicability analysis for the proposed equipment:

- 40 CFR 63, Subpart JJJJJJ - National Emission 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 proposed boiler is a HAP area source.

§ 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 of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, 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.

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in §63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in §63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

(f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

The proposed boiler is not within a subcategory of applicable sources listed in 40 CFR 63.11200 and as defined in 40 CFR 63.11237. The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), and meets the definition of gas-fired boiler under 40 CFR 63.11237 not subject to this Subpart as provided in 40 CFR 63.11195.

§ 63.11195 .... Are any boilers not subject to this subpart?

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.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

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

(f) A hot water heater as defined in this subpart.

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) as defined in this subpart.

The proposed boiler is not within a subcategory of applicable sources listed in 40 CFR 63.11200 and as defined in 40 CFR 63.11237. The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), and meets the definition of gas-fired boiler under 40 CFR 63.11237 not subject to this Subpart as provided in 40 CFR 63.11195.

...

§ 63.11200 .... What are the subcategories of boilers?

The subcategories of boilers, as defined in §63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

The proposed boiler is not within a subcategory of applicable sources listed in 40 CFR 63.11200 and as defined in 40 CFR 63.11237. The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), and meets the definition of gas-fired boiler under 40 CFR 63.11237 not subject to this Subpart as provided in 40 CFR 63.11195.

...

§ 63.11237 .... What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

10-day rolling average *means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.*

30-day rolling average *means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.*

Annual capacity factor *means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year and the potential heat input to the boiler had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.*

Annual heat input *means the heat input for the 12 months preceding the compliance demonstration.*

Bag leak detection system *means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (i.e., baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.*

Biodiesel *means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see §63.14).*

Biomass *means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.*

Biomass subcategory *includes any boiler that burns any biomass and is not in the coal subcategory.*

Boiler *means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

Boiler system *means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.*

Calendar year *means the period between January 1 and December 31, inclusive, for a given year.*

Coal *means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.*

Coal subcategory *includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.*

Commercial boiler *means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.*

Common stack *means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.*

Daily block average *means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.*

Deviation *(1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:*

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil *means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §63.14).*

Dry scrubber *means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers are included in this definition. A dry scrubber is a dry control system.*

Dry scrubber *means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.*

Electric boiler *means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.*

Electric utility steam generating unit (EGU) *means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.*

Electrostatic precipitator (ESP) *means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.*

Energy assessment *means the following for the emission units covered by this subpart:*

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management program *means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.*

Energy use system *(1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:*

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

Equivalent *means the following only as this term is used in Table 5 to this subpart:*

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) *An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.*

(4) *An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.*

(5) *An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.*

(6) *An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.*

Fabric filter *means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.*

Federally enforceable *means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.*

Fluidized bed boiler *means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.*

Fluidized bed combustion *means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.*

Fossil fuel *means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.*

Fuel type *means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.*

Gaseous fuels *includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.*

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 for periodic testing, maintenance, or operator training on liquid fuel. Periodic testing, maintenance, or operator training on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.*

Heat input *means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.*

Hot water heater *means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.*

Hourly average *means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.*

Industrial boiler *means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.*

Institutional boiler *means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.*

Limited-use boiler *means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable annual capacity factor of no more than 10 percent.*

Liquid fuel *includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil.*

Load fraction *means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5). For boilers that co-fire natural gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (e.g., if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas, the load fraction is 0.5).*

Minimum activated carbon injection rate *means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.*

Minimum oxygen level *means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.*

Minimum scrubber liquid flow rate *means the lowest hourly average scrubber liquid flow rate (e.g., to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.*

Minimum scrubber pressure drop *means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.*

Minimum sorbent injection rate *means:*

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power *means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.*

Natural gas *means:*

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (i.e., a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8.

Oil subcategory *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.*

Opacity *means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.*

Operating day *means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.*

Oxygen analyzer system *means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.*

Oxygen trim system *means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller or draft controller.*

Particulate matter (PM) *means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.*

Performance testing *means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.*

Period of gas curtailment or supply interruption *means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.*

Process heater *means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.*

Qualified energy assessor *means:*

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream *means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.*

Residential boiler *means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:*

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil *means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see §63.14(b)).*

Responsible official *means responsible official as defined in §70.2.*

Seasonal boiler *means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.*

Shutdown *means the period in which cessation of operation of a boiler is initiated for any purpose. Shutdown begins when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, or when no fuel is being fed to the boiler, whichever is earlier. Shutdown ends when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, and no fuel is being combusted in the boiler.*

Solid fossil fuel *includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.*

Solid fuel *means any solid fossil fuel or biomass or bio-based solid fuel.*

Startup *means:*

(1) Either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy (such as steam or hot water) from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating, cooling or process purposes or producing electricity, or the firing of fuel in a boiler for any purpose after a shutdown event. Startup ends 4 hours after when the boiler supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, whichever is earlier.

Temporary boiler *means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:*

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Tune-up *means adjustments made to a boiler in accordance with the procedures outlined in §63.11223(b).*

Ultra-low-sulfur liquid fuel *means a distillate oil that has less than or equal to 15 parts per million (ppm) sulfur.*

Useful thermal energy *means energy (i.e., steam or hot water) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler.*

Vegetable oil *means oils extracted from vegetation.*

Voluntary Consensus Standards *(VCS) mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, http://www.astm.org), American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, http://www.asme.org), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, http://www.iso.org/iso/home.htm), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, +61 2 9237 6171 http://www.standards.org.au), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, http://www.bsigroup.com), Canadian Standards Association (CSA, 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, http://www.csa.ca), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, http://www.cen.eu/cen), and German Engineering Standards (VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, http://www.vdi.eu). The types of standards that are not considered VCS are standards developed by: the United States, e.g., California Air Resources Board (CARB) and Texas Commission on Environmental Quality (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. Government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.*

Waste heat boiler *means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.*

Wet scrubber *means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.*

Work practice standard *means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.*

The proposed boiler is not within a subcategory of applicable sources listed in 40 CFR 63.11200 and as defined in 40 CFR 63.11237. The proposed boiler is permitted to fire only natural gas (Permit Condition 2.6), and meets the definition of gas-fired boiler under 40 CFR 63.11237 not subject to this Subpart as provided in 40 CFR 63.11195.

Permit Conditions Review

This section describes only those permit conditions that have been added or revised as a result of this permitting action.

Revised Permit Conditions 1.1 and 2.1 *(Permit Conditions 1.4, 2.1, and 2.2 of P-2009.0091 Project 61832)*

Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 REGULATED SOURCES

Permit Section	*Source*	*Control Equipment*
2	*Grain Receiving* *Truck unloading* *Train unloading*	*Truck unloading* *Choke feed* *Train unloading* *Choke feed and shroud*
	Grain Handling	*Enclosure*
	Grain Storage *Ten (10) Permanent Storage Bins*	*Mineral Oil Application* *Control Efficiency: 90%*

	Temporary Storage Piles	
	Grain Milling *Hammermill Nos. 1, 2, 3, 4, & 5* *Mfr: Bliss* *Model: N/A* *Year of Mfr: 2007*	*Mineral Oil Application* *Control Efficiency: 20%* *Hammermill Nos. 1, 2, & 3* *Baghouse Nos. 1, 2, & 3* *Mfr: Air Lanco* *Model: 49AVS10* *Year of Mfr: 2007* *Type: Pulse jet filter* *Size of Bags: 6 in. by 10 ft.* *No. of Bags: 49* *Air to Cloth Ratio: 6.4 to 1* *Control Efficiency: 99%* *Hammermill Nos. 4 & 5* *Cyclone Nos. 1 & 2* *Mfr: Bliss Industries* *Model: LE 30* *Year of Mfr: 2006* *Control Efficiency: 50%*
	Grain Shipping	*Mineral Oil Application* *Control Efficiency: 90%*

The Gavilon Grain, LLC dba Peavey Company in Burley, Idaho manufactures animal feed. To manufacture animal feed, the facility processes whole grain (corn and wheat), dried distillers grain (a byproduct of ethanol extraction), and ground corn. The facility consists of the following: six receiving pits, four distribution legs, five hammermills, sixteen conveyors, nine screw augers, fourteen storage silos, and two temporary storage piles.

Whole grain is primarily received by railcar although some may be received by truck. The grain is off-loaded into below-grade receiving pits and then edible mineral oil is applied. The application of mineral oil provides some control of fugitive dust emissions during grain handling operations. From the receiving pits, the grain is transported via drag conveyors to one of four receiving legs and then to various handling destinations within the facility. Five hammermills are used for grain grinding. Dust emissions from the hammermills are controlled by cyclones and baghouses. The processed grain is stored in silos until it is ready for shipment.

Table 2.1 GRAIN PROCESSING DESCRIPTION

Emissions Units / Processes	*Control Devices*
Grain Processing 1. *Grain Receiving* 2. *Grain Handling* 3. *Grain Storage* 4. *Grain Milling (Hammermill Nos. 1 to 5)* 5. *Grain Shipping*	*Grain Receiving* *Choke-feed, Shroud* *Grain Handling* *Enclosure* *Grain Storage* *Mineral oil application* *Grain Milling* *Mineral oil application* *Baghouse Nos. 1, 2, & 3 for Hammermill Nos. 1, 2, & 3* *Cyclone Nos. 1 & 2 for Hammermill Nos. 4 & 5* *Grain Shipping* *Mineral oil application*

Process descriptions have been updated to address proposed process and control equipment. Refer to the Permitting History section for a description of recent permitting actions.

Added Permit Condition 2.2

This permit condition establishes hourly and annual emission limits for the proposed boiler. Compliance with these emission limits is assured by complying with fuel specifications (Permit Condition 2.6).

Revised Permit Condition 2.3 *(Permit Condition 2.3 of P-2009.0091 Project 61832)*

The emissions from the grain processing operations shall not exceed any corresponding emissions rate limits listed in Table 2.2.

Table 2.2 Grain Processing Operations Emission Limits[a]

Source Description	PM_{10}[(b)] lb/hr[(c)]	PM_{10}[(b)] T/yr[(d)]
Grain Receiving	0.40	0.08
Grain Handling	0.00	0.00
Grain Storage	1.13	0.22
Grain Milling	1.90	4.20
Grain Shipping	0.15	0.03

a) In absence of any other credible evidence, compliance is assured by complying with permit operating, monitoring, and record keeping requirements.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.
d) Tons per any consecutive 12-calendar month period.

This permit condition establishes hourly and annual PM emission limits from grain processing point sources, and has been revised to also address emissions of PM_{10} from the Cyclone. Compliance with these emission limits is assured by complying with throughput (Permit Conditions 2.9–2.10) and operational limits (Permit Conditions 2.11 and 2.21); mineral oil, cyclone, and baghouse control equipment requirements (Permit Conditions 2.8, 2.12–2.16, 2.18–2.24); and performance testing requirements (Permit Conditions 2.30–2.31).

Revised Permit Condition 2.4 *(Permit Condition 2.4 of P-2009.0091 Project 61832)*

Emissions from the grain milling baghouses and cyclone stacks, or any other stack, vent, or functionally equivalent opening associated with grain processing, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

This permit condition incorporates a 20% opacity limit for all grain processing operation stacks, vents, or functionally-equivalent openings associated with grain processing, and has been revised to also address emissions from the proposed boiler stack.

Added Permit Condition 2.5

This permit condition incorporates the PM emission standard for fuel-burning equipment. The proposed boiler is fuel-burning equipment as defined in IDAPA 58.01.01.006. Compliance with this emission limit is assured by complying with fuel specifications (Permit Condition 2.6).

Added Permit Condition 2.6

This permit condition establishes limits on the type of fuel combusted in the boiler. The applicant has only proposed combustion of natural gas in the boiler, and the emission inventories and modeling analyses in the application did not consider combustion of any other fuels for purposes of demonstrating preconstruction compliance with NAAQS and TAP standards.

Added Permit Condition 2.10

This permit condition establishes throughput limits for the proposed corn flaking process. Process PM emissions are effectively limited by the grain cooling capacity (bottleneck) of the flaker coolers. This assessment is based on the proposed process design, and re-evaluation would be necessary if the process line is reconfigured.

Revised Permit Condition 2.11 *(Permit Condition 2.8 of P-2009.0091 Project 61832)*

> *Hammermill No. 1 shall not operate more than 12.0 hours per calendar day.*
>
> *Hammermill No. 2 shall not operate more than 12.0 hours per calendar day.*
>
> *Hammermill No. 3 shall not operate more than 12.0 hours per calendar day.*
>
> *Hammermill No. 4 shall not operate more than 12.0 hours per calendar day.*
>
> *Hammermill No. 5 shall not operate more than 12.0 hours per calendar day.*
>
> *Hammermills No. 1 through No. 5 shall not operate more than 21,900 hours combined per any consecutive 12-month period.*

This permit condition establishes operational limits for the hammermills. These limits were revised to permit increased hammermill operation for an additional hour per day, consistent with assumptions used in estimating and modeling facility-wide emissions to demonstrate compliance with NAAQS.

Revised Permit Condition 2.25 *(Permit Condition 2.22 of P-2009.0091 Project 61832)*

> *The permittee shall conduct a facility-wide inspection of potential sources of fugitive dust emissions, during daylight hours and under normal operating conditions once each calendar day the grain processing facility operates, to ensure that the methods used to reasonably control fugitive dust emissions are effective. If fugitive dust emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive dust emission inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive dust emissions were present (if observed), any corrective action taken in response to the fugitive dust emissions, and the date the corrective action was taken. A compilation of the most recent five years of records shall be kept onsite and made available to DEQ representatives upon request.*

This permit condition requires monitoring to ensure compliance with fugitive dust emission limits in Permit Condition 2.17 (IDAPA 58.01.01.650-651). This condition was updated to include complaint response requirements.

Added Permit Condition 2.27

These permit conditions incorporate NSPS Subpart Dc reporting and recordkeeping requirements. Refer to the NSPS Applicability (40 CFR 60) section for additional information.

Added Permit Conditions 2.29–2.31

These permit conditions require initial performance testing to verify the representativeness of the PM_{10} emission estimates and emission factor developed for the Cooler Dryer. Refer to the Emissions Inventories section for additional discussion regarding methods used in estimating these emissions.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this time, there was a request for a public comment period on DEQ's proposed action. Refer to the Application Chronology for public comment opportunity dates.

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the Application Chronology for public comment period dates.

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

APPENDIX A – EMISSIONS INVENTORIES

Gavilon Grain, LLC - Burley
Flaking System Project Emission Units

Emission Unit #	Emission Unit Description	Maximum Capacity (bushels/hr)	Maximum Capacity (tons/hr)
H3	Bin 4 Enclosed Sidedraw Spout and Conveyor	5,000	140
H4	Bin 5 Enclosed Sidedraw Spout and Conveyor	5,000	140
H5	Flaking System Transfer Leg	5,000	140
H6	Flaking System Transfer Belt Conveyor	5,000	140
Bin11	Flaking System Storage Bin	5,000 fill	140
		30,000 storage	840
H7	Flaking System Storage Bin Reclaim Conveyor	5,000	140
H8	Flaking System Charge Leg	5,000	140
CL1	Rotary Grain Cleaner	5,000	140
CL2	Drop Removed FM to Storage Container	-	1.40
H9	Flaking System Mixing Auger	5,000	140
FL1	Flaker Cooler Cyclone	-	25
FL2	Flake Transfer Conveyor	-	25
FL3	Flake Leg	-	25
FL4	Flake Storage Barn Overhead Conveyor	-	25
FL5	Drop to Flake Storage Piles in Flake Storage Barn	-	25
FL6	Flake Storage Pile Handling	-	100
FL7	Flake Dump Pit	-	100
FL8	Flake Truck Loadout Spout	-	100
RC1	Existing Facility Replacement Drag Conveyor	25,000	700

Emission Unit #	Emission Unit Description	Maximum Capacity (MMBtu/hr)
B1	Natural Gas Steam Boiler	16.737

Gavilon Grain, LLC - Burley
Flaking Project Potential Emissions Summary

Emissions Totals (lbs/hr)

Process	PM	PM10	PM2.5	SO2	NOx	CO	VOCs	CO_2e
Grain and Flake Handling	0.37	0.10	0.02	-	-	-	-	-
Grain Cleaning	0.88	0.49	0.08					
Flake Storage Pile Handling and Shipping	0.04	0.02	0.00	-	-	-	-	-
Natural Gas Steam Boiler	0.08	0.08	0.08	0.02	1.61	0.62	0.13	579.42
Total	**1.37**	**0.69**	**0.18**	**0.02**	**1.61**	**0.62**	**0.13**	**579.42**

Emissions Totals (tons/yr)

Process	PM	PM10	PM2.5	SO2	NOx	CO	VOCs	CO_2e
Grain and Flake Handling	1.63	0.43	0.07	-	-	-	-	-
Grain Cleaning	3.85	2.15	0.37					
Flake Storage Pile Handling and Shipping	0.19	0.09	0.01	-	-	-	-	-
Natural Gas Steam Boiler	0.35	0.35	0.35	0.07	7.04	2.71	0.59	2,537.87
Total	**6.02**	**3.02**	**0.80**	**0.07**	**7.04**	**2.71**	**0.59**	**2,537.87**

Gavilon Grain, LLC - Burley
Grain and Flake Handling PTE
PM Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capacity	PM Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total PM Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
H3	Bin 4 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
H4	Bin 5 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
H5	Flaking System Transfer Leg	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
H6	Flaking System Transfer Belt Conveyor	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
Bin11	Flaking System Storage Bin	Mineral Oil	140	0.025	3.50	15.33	90%	0.35	1.53
H7	Flaking System Storage Bin Reclaim Conveyor	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
H8	Flaking System Charge Leg	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
H9	Flaking System Mixing Auger	Enclosed & Mineral Oil	140	0.061	8.54	37.41	100%	0.00	0.00
FL1	Flaker Cooler Cyclone[3]	Cyclone	25	8.80E-04	2.20E-02	0.10	0%	0.02	0.10
FL2	Flake Transfer Conveyor	Enclosed	25	0.061	1.53	6.68	100%	0.00	0.00
FL3	Flake Leg	Enclosed	25	0.061	1.53	6.68	100%	0.00	0.00
FL4	Flake Storage Barn Overhead Conveyor	Enclosed	25	0.061	1.53	6.68	100%	0.00	0.00
							Total	**0.37**	**1.63**

[1] Except for FL1: Flaker Cooler Cyclone, emission factors are from AP-42, Chapter 9, Table 9.9.1-1.

[2] Enclosed & Mineral Oil control efficiency and mineral oil alone control efficiency from Permit to Construct P-2009.0091, Project ID 61051, issued to Gavilon on July 12, 2012. Two-sided enclosure control efficiency taken from "Grain Elevator and Grain Processing Air Quality Permits and Reports, Published by MU Extension, University of Missouri-Columbia.

[3] Emission factor for flaker cooler from: Purswell, Anissa M., W. B. Faulkner, and C.A. Spencer, "Determination of Emission Factors for Steam Flaking of Corn at a Commercial Feedmill," Presented July 2012 at the American Society of Agricultural and Biological Engineers Annual International Meeting. The emission factors presented in this paper are based on Method 5 testing of a cooler cyclone connected to a corn flaker roller and cooler rated at 13 tons per hour. The Gavilon flaker roller and cooler is rated at 25 tons per hour. Therefore, Gavilon doubled the emission factor from the paper in order to be more representative of the Gavilon system. Gavilon also added a 10 percent safety factor in order to more conservatively estimate emissions from the flaker cooler.

Gavilon Grain, LLC - Burley
Grain and Flake Handling PTE
PM_{10} Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	PM_{10} Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total PM_{10} Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
H3	Bin 4 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
H4	Bin 5 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
H5	Flaking System Transfer Leg	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
H6	Flaking System Transfer Belt Conveyor	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
Bin11	Flaking System Storage Bin	Mineral Oil	140	0.0063	0.88	3.86	90%	0.09	0.39
H7	Flaking System Storage Bin Reclaim Conveyor	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
H8	Flaking System Charge Leg	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
H9	Flaking System Mixing Auger	Enclosed & Mineral Oil	140	0.034	4.76	20.85	100%	0.00	0.00
FL1	Flaker Cooler[3]	Cyclone	25	4.40E-04	1.10E-02	0.05	0%	0.01	0.05
FL2	Flake Transfer Conveyor	Enclosed	25	0.034	0.85	3.72	100%	0.00	0.00
FL3	Flake Leg	Enclosed	25	0.034	0.85	3.72	100%	0.00	0.00
FL4	Flake Storage Barn Overhead Conveyor	Enclosed	25	0.034	0.85	3.72	100%	0.00	0.00
							Total	**0.10**	**0.43**

[1] Except for FL1: Flaker Cooler Cyclone, emission factors are from AP-42, Chapter 9, Table 9.9.1-1.

[2] Enclosed & Mineral Oil control efficiency and mineral oil alone control efficiency from Permit to Construct P-2009.0091, Project ID 61051, issued to Gavilon on July 12, 2012. Two-sided enclosure control efficiency taken from "Grain Elevator and Grain Processing Air Quality Permits and Reports, Published by MU Extension, University of Missouri-Columbia.

[3] Emission factor for flaker cooler from: Purswell, Anissa M., W. B. Faulkner, and C.A. Spencer, "Determination of Emission Factors for Steam Flaking of Corn at a Commercial Feedmill," Presented July 2012 at the American Society of Agricultural and Biological Engineers Annual International Meeting. The emission factors presented in this paper are based on Method 5 testing of a cooler cyclone connected to a corn flaker roller and cooler rated at 13 tons per hour. The Gavilon flaker roller and cooler is rated at 25 tons per hour. Therefore, Gavilon doubled the emission factor from the paper in order to be more representative of the Gavilon system. Gavilon also added a 10 percent safety factor in order to more conservatively estimate emissions from the flaker cooler.

Gavilon Grain, LLC - Burley
Grain and Flake Handling PTE
$PM_{2.5}$ Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	$PM_{2.5}$ Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total $PM_{2.5}$ Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
H3	Bin 4 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
H4	Bin 5 Enclosed Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
H5	Flaking System Transfer Leg	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
H6	Flaking System Transfer Belt Conveyor	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
Bin11	Flaking System Storage Bin	Mineral Oil	140	0.0011	0.15	0.67	90%	0.02	0.07
H7	Flaking System Storage Bin Reclaim Conveyor	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
H8	Flaking System Charge Leg	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
H9	Flaking System Mixing Auger	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	100%	0.00	0.00
FL1	Flaker Cooler[3]	Cyclone	25	1.77E-05	4.42E-04	1.94E-03	0%	0.00	1.94E-03
FL2	Flake Transfer Conveyor	Enclosed	25	0.0058	0.15	0.64	100%	0.00	0.00
FL3	Flake Leg	Enclosed	25	0.0058	0.15	0.64	100%	0.00	0.00
FL4	Flake Storage Barn Overhead Conveyor	Enclosed	25	0.0058	0.15	0.64	100%	0.00	0.00
							Total	**0.02**	**0.07**

[1] Except for FL1: Flaker Cooler Cyclone, emission factors are from AP-42, Chapter 9, Table 9.9.1-1.

[2] Enclosed & Mineral Oil control efficiency and mineral oil alone control efficiency from Permit to Construct P-2009.0091, Project ID 61051, issued to Gavilon on July 12, 2012. Two-sided enclosure control efficiency taken from "Grain Elevator and Grain Processing Air Quality Permits and Reports, Published by MU Extension, University of Missouri-Columbia.

[3] Emission factor for flaker cooler from: Purswell, Anissa M., W. B. Faulkner, and C.A. Spencer, "Determination of Emission Factors for Steam Flaking of Corn at a Commercial Feedmill," Presented July 2012 at the American Society of Agricultural and Biological Engineers Annual International Meeting. The emission factors presented in this paper are based on Method 5 testing of a cooler cyclone connected to a corn flaker roller and cooler rated at 13 tons per hour. The Gavilon flaker roller and cooler is rated at 25 tons per hour. Therefore, Gavilon doubled the emission factor from the paper in order to be more representative of the Gavilon system. Gavilon also added a 10 percent safety factor in order to more conservatively estimate emissions from the flaker cooler.

Gavilon Grain, LLC - Burley
Grain Cleaner PTE

Cleaner PM Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capacity	PM Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total PM Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
CL1	Rotary Grain Cleaner	Enclosed & Mineral Oil	140	0.061	8.54	37.41	90%	0.85	3.74

[1] Emission factor from AP-42, Chapter 9, Table 9.9.1-1.

[2] The rotary grain cleaner does not vent to the atmosphere through a cyclone or baghouse. Therefore, in accordance with AP-42, Chapter 9.9.1 - Grain Elevators and Processes, Gavilon used the headhouse and internal handling emission factor to estimate emissions (See page 9.9.1-19, Item 4). While the cleaner unit is enclosed, it does utilize a rotating drum and screens. Gavilon conservatively estmated the control efficiency of the cleaner to be 90 percent due to this design and the use of food-grade mineral oil.

Removed Foreign Material (FM) PM Emissions

Emission Unit #	Emission Unit Description	Control Equipment[3]	Grain Cleaned	% Foreign Material[4]	Foreign Material Removed	Foreign Material Removed	PM Emission Factor[5]	Control Efficiency	Total PM Emissions	
			(tons/hr)	(%)	(tons/hr)	(tons/yr)	(lb/ton)	%	(lb/hr)	(tpy)
			H	I	J=H*I	K=J*8760	L	M	N=J*L*(1-M)	O=K*L*(1-M)/2000
CL2	Drop Removed FM to Storage Container	Mineral Oil	140	1.0%	1.40	12,264	0.061	70%	0.03	0.11

[3] All incoming grain is coated with mineral oil for dust suppresant. Although the foreign material is not grain, it is present in the grain stream when mineral oil is applied. Therefore, the foreign material is also coated with mineral oil for dust suppressant. Gavilon has assumed 90 percent control for use of mineral oil for other grain handling processes. However, for added conservatism, Gavilon has assumed 70 percent control for emissions related to the drop of foreign material at the cleaner.

[4] Percent foreign material determined from 2016 harvest information published by U.S. Grains Council (see Page 14 of report). Annual average aggregate percent foreign material of 2016 corn harvest was 0.1 percent. Document also states that 94.2 percent of samples contained less than 0.5 percent foreign material. Based on this data, Gavilon has used 1.0 percent foreign material to estimate potential emissions of foreign material dropped from the proposed cleaner to the screenings storage unit. Assuming 1.0 percent foreign material is extremely conservative when compared to the information from the U.S. Grains Council.

[5] Emission factors from AP-42, Chapter 9, Table 9.9.1-1 for internal handling of grain. There are no published emission factors for handling of foreign material at grain elevators.

Gavilon Grain, LLC - Burley
Grain Cleaner PTE

Cleaner PM10 Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capacity	PM10 Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total PM10 Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
CL1	Rotary Grain Cleaner	Enclosed & Mineral Oil	140	0.034	4.76	20.85	90%	0.48	2.08

[1] Emission factor from AP-42, Chapter 9, Table 9.9.1-1.

[2] The rotary grain cleaner does not vent to the atmosphere through a cyclone or baghouse. Therefore, in accordance with AP-42, Chapter 9.9.1 - Grain Elevators and Processes, Gavilon used the headhouse and internal handling emission factor to estimate emissions (See page 9.9.1-19, Item 4). While the cleaner unit is enclosed, it does utilize a rotating drum and screens. Gavilon conservatively estmated the control efficiency of the cleaner to be 90 percent due to this design and the use of food-grade mineral oil.

Removed Foreign Material (FM) PM10 Emissions

Emission Unit #	Emission Unit Description	Control Equipment[3]	Grain Cleaned	% Foreign Material[4]	Foreign Material Removed	Foreign Material Removed	PM10 Emission Factor[5]	Control Efficiency	Total PM10 Emissions	
			(tons/hr)	(%)	(tons/hr)	(tons/yr)	(lb/ton)	%	(lb/hr)	(tpy)
			H	I	J=H*I	K=J*8760	L	M	N=J*L*(1-M)	O=K*L*(1-M)/2000
CL2	Drop Removed FM to Storage Container	Mineral Oil	140	1.0%	1.40	12,264	0.034	70%	0.01	0.06

[3] All incoming grain is coated with mineral oil for dust suppresant. Although the foreign material is not grain, it is present in the grain stream when mineral oil is applied. Therefore, the foreign material is also coated with mineral oil for dust suppressant. Gavilon has assumed 90 percent control for use of mineral oil for other grain handling processes. However, for added conservatism, Gavilon has assumed 70 percent control for emissions related to the drop of foreign material at the cleaner.

[4] Percent foreign material determined from 2016 harvest information published by U.S. Grains Council (see Page 14 of report). Annual average aggregate percent foreign material of 2016 corn harvest was 0.1 percent. Document also states that 94.2 percent of samples contained less than 0.5 percent foreign material. Based on this data, Gavilon has used 1.0 percent foreign material to estimate potential emissions of foreign material dropped from the proposed cleaner to the screenings storage unit. Assuming 1.0 percent foreign material is extremely conservative when compared to the information from the U.S. Grains Council.

[5] Emission factors from AP-42, Chapter 9, Table 9.9.1-1 for internal handling of grain. There are no published emission factors for handling of foreign material at grain elevators.

Gavilon Grain, LLC - Burley
Grain Cleaner PTE

Cleaner PM2.5 Emissions

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capacity	PM2.5 Emission Factor[1]	Emission Rate		Control Efficiency[2]	Total PM2.5 Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
CL1	Rotary Grain Cleaner	Enclosed & Mineral Oil	140	0.0058	0.81	3.56	90%	0.08	0.36

[1] Emission factor from AP-42, Chapter 9, Table 9.9.1-1.

[2] The rotary grain cleaner does not vent to the atmosphere through a cyclone or baghouse. Therefore, in accordance with AP-42, Chapter 9.9.1 - Grain Elevators and Processes, Gavilon used the headhouse and internal handling emission factor to estimate emissions (See page 9.9.1-19, Item 4). While the cleaner unit is enclosed, it does utilize a rotating drum and screens. Gavilon conservatively estmated the control efficiency of the cleaner to be 90 percent due to this design and the use of food-grade mineral oil.

Removed Foreign Material (FM) PM2.5 Emissions

Emission Unit #	Emission Unit Description	Control Equipment[3]	Grain Cleaned	% Foreign Material[4]	Foreign Material Removed	Foreign Material Removed	PM2.5 Emission Factor[5]	Control Efficiency	Total PM2.5 Emissions	
			(tons/hr)	(%)	(tons/hr)	(tons/yr)	(lb/ton)	%	(lb/hr)	(tpy)
			H	I	J=H*I	K=J*8760	L	M	N=J*L*(1-M)	O=K*L*(1-M)/2000
CL2	Drop Removed FM to Storage Container	Mineral Oil	140	1.0%	1.40	12,264	0.0058	70%	2.44E-03	0.011

[3] All incoming grain is coated with mineral oil for dust suppresant. Although the foreign material is not grain, it is present in the grain stream when mineral oil is applied. Therefore, the foreign material is also coated with mineral oil for dust suppressant. Gavilon has assumed 90 percent control for use of mineral oil for other grain handling processes. However, for added conservatism, Gavilon has assumed 70 percent control for emissions related to the drop of foreign material at the cleaner.

[4] Percent foreign material determined from 2016 harvest information published by U.S. Grains Council (see Page 14 of report). Annual average aggregate percent foreign material of 2016 corn harvest was 0.1 percent. Document also states that 94.2 percent of samples contained less than 0.5 percent foreign material. Based on this data, Gavilon has used 1.0 percent foreign material to estimate potential emissions of foreign material dropped from the proposed cleaner to the screenings storage unit. Assuming 1.0 percent foreign material is extremely conservative when compared to the information from the U.S. Grains Council.

[5] Emission factors from AP-42, Chapter 9, Table 9.9.1-1 for internal handling of grain. There are no published emission factors for handling of foreign material at grain elevators.

Gavilon Grain, LLC - Burley
Emission Factor Calculation for Corn Flake Pile Handling

Emissions for corn flake storage, and shipping are based on predictive emissions equation presented in AP-42 Chapter 13.2.4, Aggregate Handling and Storge Piles. Processed grain flakes no longer have the same physical composition of physical grain, and are handled more like bulk materials. The distinct activities listed in AP-42, Chapter 13.2.4.3 most closely resemble the flaked grain hanlding operations at Gavilon: loading of flakes onto storage piles; equipment traffic (end loaders and shipping trucks) in the storage area; wind erosion of pile surfaces and ground areas around piles; and loadout of flakes for shipment or return to the process stream.

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

E = Emission factor (lb/ton)
U = mean wind speed, miles per hour (mph)
M = material moisture content (%)
k = particle size multiplier

Particle	Chapter 13.2.4.3 Value for k
PM	0.74
PM_{10}	0.35
$PM_{2.5}$	0.053

Emission Factors for outdoor wind speed:

k (PM)	k (PM_{10})	k ($PM_{2.5}$)	U (1)	M(2)	E (PM)	E (PM_{10})	E ($PM_{2.5}$)
0.74	0.35	0.05	10	18.30%	0.00026	0.00012	0.00002

(1) Average outdoor wind speed obtained from NOAA Climatic Wind Data for the United States for Pocatello, ID. Pocatello, ID is the closest meteorological station to the facility in Burley, ID. Wind speed records include all available data from 1930-1996. http://ncdc.noaa.gov/sites/default/files/attachments/wind1996.pdf

(2) According to Figure 1 of "Steam Flaking - Focus on Conditioning," produced by Roskamp Champion in 1999, final moisture content of steam flaked grains ranges between 14.2% and 23.3%. As a conservative estimate of moisture content, Gavilon chose 18.3%, which is the middle of the range of values presented. Please see https://www.cpm.net/downloads/Steam%20Flaking.pdf for further details

Gavilon Grain, LLC - Burley
Corn Flake Pile PTE

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	PM Emission Factor	Emission Rate		Control Efficiency[1]	Total PM Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
FL5	Drop to Flake Storage Piles in Flake Storage Barn	2-Sided Enclosure	25	2.63E-04	6.57E-03	0.03	50%	3.29E-03	0.01
FL6	Flake Storage Pile Handling	2-Sided Enclosure	100	2.63E-04	2.63E-02	0.12	50%	1.31E-02	0.06
FL7	Flake Dump Pit	2-Sided Enclosure	100	2.63E-04	2.63E-02	0.12	50%	1.31E-02	0.06
FL8	Flake Truck Loadout Spout	2-Sided Enclosure	100	2.63E-04	2.63E-02	0.12	50%	1.31E-02	0.06
							Total	**4.27E-02**	**0.19**

[1] Control efficiency obtained from Downs, W. and Pfost, D.L., "Grain Elevator and Grain Processing Air Quality Permits and Reports," published by University of Missouri Extension. Gavilon used the control efficiency for a 2-sided enclosure to conservatively estimate emissions. Gavilon assumed a 2-sided enclosure because there are times that both garage door openings of the flake storage barn will be open at the same time.

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	PM10 Emission Factor	Emission Rate		Control Efficiency[1]	Total PM10 Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
FL5	Drop to Flake Storage Piles in Flake Storage Barn	2-Sided Enclosure	25	1.24E-04	3.11E-03	0.01	50%	1.55E-03	0.01
FL6	Flake Storage Pile Handling	2-Sided Enclosure	100	1.24E-04	1.24E-02	0.05	50%	6.22E-03	0.03
FL7	Flake Dump Pit	2-Sided Enclosure	100	1.24E-04	1.24E-02	0.05	50%	6.22E-03	0.03
FL8	Flake Truck Loadout Spout	2-Sided Enclosure	100	1.24E-04	1.24E-02	0.05	50%	6.22E-03	0.03
							Total	**2.02E-02**	**0.09**

[1] Control efficiency obtained from Downs, W. and Pfost, D.L., "Grain Elevator and Grain Processing Air Quality Permits and Reports," published by University of Missouri Extension. Gavilon used the control efficiency for a 2-sided enclosure to conservatively estimate emissions. Gavilon assumed a 2-sided enclosure because there are times that both garage door openings of the flake storage barn will be open at the same time.

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	PM2.5 Emission Factor	Emission Rate		Control Efficiency[1]	Total PM2.5 Emissions	
			(tons/hr)	(lb/ton)	(lb/hr)	(tpy)	%	(lb/hr)	(tpy)
			A	B	C=A*B	D=C*8760/2000	E	F=C*(1-E)	G=D*(1-E)
FL5	Drop to Flake Storage Piles in Flake Storage Barn	2-Sided Enclosure	25	1.88E-05	4.71E-04	2.06E-03	50%	2.35E-04	1.03E-03
FL6	Flake Storage Pile Handling	2-Sided Enclosure	100	1.88E-05	1.88E-03	8.25E-03	50%	9.41E-04	4.12E-03
FL7	Flake Dump Pit	2-Sided Enclosure	100	1.88E-05	1.88E-03	8.25E-03	50%	9.41E-04	4.12E-03
FL8	Flake Truck Loadout Spout	2-Sided Enclosure	100	1.88E-05	1.88E-03	8.25E-03	50%	9.41E-04	4.12E-03
							Total	**3.06E-03**	**1.34E-02**

[1] Control efficiency obtained from Downs, W. and Pfost, D.L., "Grain Elevator and Grain Processing Air Quality Permits and Reports," published by University of Missouri Extension. Gavilon used the control efficiency for a 2-sided enclosure to conservatively estimate emissions. Gavilon assumed a 2-sided enclosure because there are times that both garage door openings of the flake storage barn will be open at the same time.

Gavilon Grain, LLC - Burley
Flaking Steam Boiler - B1

Natural Gas

Total design rate of boiler:	16.737	MMBtu/hr[1] [A]
Operating hours:	8,760	hrs/yr [B]
Heat content:	1,000	MMBtu/MMscf[1]
Potential throughput:	0.017	MMscf/hr [C]
Potential throughput:	146.616	MMscf/yr [D]

[1] Information from manufacturer specs for Superior Boiler Works, Inc., Boiler Model 8-5-2000-S150 Apache

Pollutant	Emission Factor[1] (lbs/MMBtu)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
	[E]	[F]= [A] * [E]	[G] = [B]*[F]/2000
$PM_{2.5}$	0.0048	0.08	0.35
PM_{10}	0.0048	0.08	0.35
PM	0.0048	0.08	0.35
SO_2	0.001	0.02	0.07
NO_x	0.096	1.61	7.04
CO	0.037	0.62	2.71
VOC	0.008	0.13	0.59

[1] Emission factors are provided by the burner vendor

Greenhouse Gases	Emission Factor[2] (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)	Global Warming Potential[3]	Potential CO2e Hourly Emissions (lbs/hr)	Potential CO2e Annual Emissions (tons/yr)
	[H]	[I]= [C] * [H]	[J] = [D]*[H]/2000	[K]	[L]= [I] * [K]	[M] = [J]*[K]/2000
CO_2	120,000	576.00	2,522.88	1	576.00	2,522.88
N_2O	2.2	0.01	0.05	298	3.15	13.78
Methane	2.3	0.01	0.05	25	0.28	1.21
Total CO_2 Mass		576.02	2,522.97			
Total CO_2e					579.42	2,537.87

[2] Emission Factors from AP-42, Chapter 1, Section 1.4, Table 1.4-2
[3] Global Warming Potentials from 40 CFR Part 98, Subpart A, Table A-1

Gavilon Grain, LLC - Burley
Flaking Steam Boiler - B1

Natural Gas

Total design rate of boiler:	16.737	MMBtu/hr[1] [A]
Operating hours:	8,760	hrs/yr [B]
Heat content:	1,000	MMBtu/MMscf[1]
Potential throughput:	0.017	MMscf/hr [C]
Potential throughput:	146.616	MMscf/yr [D]

[1] Information from manufacturer specs for Superior Boiler Works, Inc., Boiler Model 8-5-2000-S150 Apache

Pollutant	CAS Number	Emission Factor[4] (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)	Idaho DEQ Screening Emission Levels (lbs/hr)	Modeling Required (yes/no)
		[N]	[O] = [C] * [N]	[P] = [D] * [N] / 2000		
2-Methylnaphthalene[5]	91-57-6	2.40E-05	4.02E-07	1.76E-06		
3-Methylchloranthrene	56-49-5	1.80E-06	3.01E-08	1.32E-07	2.50E-06	No
7,12-Dimethylbenz(a)anthracene[5]	-	1.60E-05	2.68E-07	1.17E-06		
Acenaphthene[6]	83-32-9	1.80E-06	3.01E-08	1.32E-07		
Acenaphthylene[6]	208-96-8	1.80E-06	3.01E-08	1.32E-07		
Anthracene[6]	120-12-7	2.40E-06	4.02E-08	1.76E-07		
Benzo(a)anthracene[7]	56-55-3	1.80E-06	3.01E-08	1.32E-07		
Benzene	71-43-2	2.10E-03	3.51E-05	1.54E-04	8.00E-04	No
Benzo(a)pyrene	50-32-8	1.20E-06	2.01E-08	8.80E-08	2.00E-06	No
Benzo(b)fluoranthene[7]	205-99-2	1.80E-06	3.01E-08	1.32E-07		
Benzo(g,h,i)perylene[6]	191-24-2	1.20E-06	2.01E-08	8.80E-08		
Benzo(k)fluoranthene[7]	207-08-9	1.80E-06	3.01E-08	1.32E-07		
Butane	106-97-8	2.1	3.51E-02	1.54E-01		
Chrysene[7]	218-01-9	1.80E-06	3.01E-08	1.32E-07		
Dibenzo(a,h)anthracene[7]	53-70-3	1.20E-06	2.01E-08	8.80E-08		
Dichlorobenzene[8]	25321-22-6	1.20E-03	2.01E-05	8.80E-05	20.00	No
Ethane	74-84-0	3.1	5.19E-02	2.27E-01		
Fluoranthene[6]	206-44-0	3.00E-06	5.02E-08	2.20E-07		
Fluorene[6]	86-73-7	2.80E-06	4.69E-08	2.05E-07		
Formaldehyde	50-00-0	7.50E-02	1.26E-03	5.50E-03	5.10E-04	Yes
n-Hexane	110-54-3	1.8	3.01E-02	1.32E-01	12	No

Pollutant	CAS Number	Emission Factor[4] (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)	Idaho DEQ Screening Emission Levels (lbs/hr)	Modeling Required (yes/no)
		[N]	[O] = [C] * [N]	[P] = [D] * [N] / 2000		
Indeno(1,2,3-cd)pyrene[7]	193-39-5	1.80E-06	3.01E-08	1.32E-07		
Napthalene	91-20-3	6.10E-04	1.02E-05	4.47E-05	3.33	No
Pentane	109-66-0	2.6	4.35E-02	1.91E-01	118.00	No
Phenanathrene[6]	85-01-8	1.70E-05	2.85E-07	1.25E-06		
Propane	74-98-6	1.6	2.68E-02	1.17E-01		
Pyrene[6]	129-00-0	5.00E-06	8.37E-08	3.67E-07		
Toluene	108-88-3	3.40E-03	5.69E-05	2.49E-04	25	No
Arsenic Compounds	7440-38-2	2.00E-04	3.35E-06	1.47E-05	1.50E-06	Yes
Barium Compounds	7440-39-3	4.40E-03	7.36E-05	3.23E-04	3.30E-02	No
Beryllium Compounds	7440-41-7	1.20E-05	2.01E-07	8.80E-07	2.80E-05	No
Cadmium Compounds	7440-43-9	1.10E-03	1.84E-05	8.06E-05	3.70E-06	Yes
Chromium Compounds	7440-47-3	1.40E-03	2.34E-05	1.03E-04	3.30E-02	No
Cobalt Compounds	7440-48-4	8.40E-05	1.41E-06	6.16E-06	3.30E-03	No
Copper Compunds	7440-50-8	8.50E-04	1.42E-05	6.23E-05	1.30E-02	No
Lead Compounds	-	5.00E-04	8.37E-06	3.67E-05	14 lbs/month	No (8.37E-06 lb/hr equates to 0.006 lb/month, assuming 24 hours per day and 31 days per month)
Manganese Compounds	7439-96-5	3.80E-04	6.36E-06	2.79E-05	6.70E-02	No
Mercury Compounds	7439-97-6	2.60E-04	4.35E-06	1.91E-05		
Molybdenum Compounds	7439-98-7	1.10E-03	1.84E-05	8.06E-05	3.33E-01	No
Nickel Compounds	7440-02-0	2.10E-03	3.51E-05	1.54E-04	2.70E-05	Yes
Selenium Compounds	7782-49-2	2.40E-05	4.02E-07	1.76E-06	1.30E-02	No
Vanadium Compounds[8]	7440-62-2	2.30E-03	3.85E-05	1.69E-04	3.00E-03	No
Zinc Compounds	7440-66-6	2.90E-02	4.85E-04	2.13E-03	6.67E-01	No
Mineral Oil Mist[9]	--	--	0.00E+00	0.00E+00	3.33E-01	No

[4] Emission factors are from AP-42 Chapter 1, Section 1.4, Tables 1.4-2, 1.4-3, and 1.4-4.

[5] Identified as Polycyclic Organic Matter (POM) in AP-42 Chapter 1, Section 1.4. However, IDAPA 58.01.01.586 does not include pollutant as part of POM. The pollutant is not considered a polyaromatic hydrocarbon (PAH) and no individual IDEQ TAP screening level is provided for pollutant.

[6] Considered PAH. There is no individual IDEQ TAP screening level for this pollutant. Pollutant is aggregated with others identifed with this footnote to determine if TAP modeling should be conducted for PAH

[7] Considered POM (7-PAH Group) under IDAPA 58.01.01.586. There is no individual IDEQ TAP screening level for this pollutant. Pollutant is aggregated with others identifed with this footnote to determine if TAP modeling should be conducted for POM

[8] CAS number for dichlorobenzene and vanadium differ between AP-42 and that listed in IDAPA 58.01.01.585-586. While the differening CAS numbers indicate that the compunds listed in IDAPA 58.01.01.585-586 could be different than the compounds listed in AP-42, Gavilon has opted to use IDEQ TAP screening levels as listed in order to ensure compliance with IDEQ TAP modeling requirements.

[9] Mineral oil is applied to grain within an enclosed internal grain transfer system. Due to the design, mineral oil mist cannot be emitted from the system

Pollutant	Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)	Idaho DEQ TAP Screening Emission Levels (lbs/hr)	Modeling Required (Yes/No)
	[N]	[O] = [C] * [N]	[P] = [D] * [N] / 2000		
Polyaromatic Hydrocarbons (Except 7-PAH Group)[10]	5.90E-05	9.87E-07	4.33E-06	9.10E-05	No
7-PAH Group (POM)[10]	5.14E-05	8.60E-07	3.77E-06	2.00E-06	No

[10] For added conservatism, Gavilon included 2-Methylnaphthalene and 7,12-Dimethylbenz(a)anthracene as part of both PAH and POM. These pollutants are identified as POM in AP-42, Chapter 1, Section 1.4, but IDEQ TAP reguations do not list these pollutants as either PAH or POM

Gavilon Grain, LLC - Burley
Process Weight Rate (PWR) Calculations

For PWR < 9,250 lb/hr: E = 0.045(PW)^0.60
For PWR >= 9,250 lb/hr: E = 1.10(PW)^0.25

Emission Unit #	Emission Unit Description	Control Equipment	Max Design Capactiy	Max Design Capactiy	PWR Limit	Controlled PM Emissions
			(tons/hr)	(lbs/hr)	(lbs/hr)	(lbs/hr)
			A	B	C	D
H3	Bin 4 Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	280,000	25.30	0.00
H4	Bin 5 Sidedraw Spout and Conveyor	Enclosed & Mineral Oil	140	280,000	25.30	0.00
H5	Flaking System Transfer Leg	Enclosed & Mineral Oil	140	280,000	25.30	0.00
H6	Flaking System Transfer Belt Conveyor	Enclosed & Mineral Oil	140	280,000	25.30	0.00
Bin11	Flaking System Storage Bin	Mineral Oil	140	280,000	25.30	0.35
H7	Flaking System Storage Bin Reclaim Conveyor	Enclosed & Mineral Oil	140	280,000	25.30	0.00
H8	Flaking System Charge Leg	Enclosed & Mineral Oil	140	280,000	25.30	0.00
CL1	Rotary Grain Cleaner	Enclosed & Mineral Oil	140	280,000	25.30	0.85
CL2	Drop Removed FM to Storage Container	Enclosed & Mineral Oil	1.40	2,800	5.27	0.03
H9	Flaking System Mixing Auger	Enclosed & Mineral Oil	140	280,000	25.30	0.00
FL1	Flaker Cooler	Cyclone	25	50,000	16.45	0.02
FL2	Flake Transfer Conveyor	Enclosed	25	50,000	16.45	0.00
FL3	Flake Leg	Enclosed	25	50,000	16.45	0.00
FL4	Flake Storage Barn Overhead Conveyor	Enclosed	25	50,000	16.45	0.00
FL5	Drop to Flake Storage Piles in Flake Storage Barn	2-Sided Enclosure	25	50,000	16.45	0.00
FL6	Flake Storage Pile Handling	2-Sided Enclosure	100	200,000	23.26	0.01
FL7	Flake Dump Pit	2-Sided Enclosure	100	200,000	23.26	0.01
FL8	Flake Truck Loadout Spout	2-Sided Enclosure	100	200,000	23.26	0.01

Gavilon Grain, LLC - Burley
Existing Facility PM Emissions

Emission Unit Description	Maximum Hourly Throughput (tons/hr)	PM Emission Factor[1] (lb/ton)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency[2] %	Controlled PM Emissions (lbs/hr)	LImited Annual Throughput (tons/yr)	Limited PM_{10} Emissions (tons/yr)
	A	B	C=A*B/2000	D	E=C*(1-E)		
Receiving							
South Green Train Pit	350	0.0170	5.95	95%	0.2975	700,000	1.1900
North Green Truck Pit[3]	280	0.0170	4.76	80%	0.9520		
South Green Truck Pit[3]	280	0.0170	4.76	80%	0.9520		
Shuttle Train Pit (feeds north and/or south conveyor)	952	0.0170	16.18	95%	0.8092		
Maximum Totals[4]			**16.18**	**-**	**1.9040**		
Handling							
North Green Distribution Leg	350	0.0610	21.35	100%	0.0000	700,000	0
South Green Distrubution Leg	350	0.0610	21.35	100%	0.0000		
North Gray Shuttle Leg	476	0.0610	29.04	100%	0.0000		
South Gray Shuttle Leg	476	0.0610	29.04	100%	0.0000		
Totals			**100.77**	**-**	**0.0000**		
Storage							
Bin 1	172	0.0250	4.30	90%	0.4300	700,000	0.88
Bin 2	172	0.0250	4.30	90%	0.4300		
Bin 3	172	0.0250	4.30	90%	0.4300		
Bin 4	172	0.0250	4.30	90%	0.4300		
Bin 5	172	0.0250	4.30	90%	0.4300		
Bin 6	172	0.0250	4.30	90%	0.4300		
Bin 7	172	0.0250	4.30	90%	0.4300		
Bin A	47	0.0250	1.17	90%	0.1167		
Bin B	47	0.0250	1.17	90%	0.1167		
Bin C	47	0.0250	1.17	90%	0.1167		
Totals			**33.60**	**-**	**3.3600**		
Milling							
Hammermill #1 (Baghouse)	40	0.0120	0.48	20%	0.3840	602,000	2.89
Hammermill #2 (Baghouse)	40	0.0120	0.48	20%	0.3840		
Hammermill #3 (Baghouse)	40	0.0120	0.48	20%	0.3840		
Hammermill #4 (Cyclone)	14	0.0670	0.94	20%	0.7504	98,000	2.63
Hammermill #5 (Cyclone)	14	0.0670	0.94	20%	0.7504		
Totals			**3.32**	**-**	**2.6528**		

Gavilon Grain, LLC - Burley
Existing Facility PM Emissions

Shipping							
Bin B-A Truck Drop Pipe	196	0.0033	0.65	90%	0.0647	700,000	0.1155
Bin B-C Truck Drop Pipe	196	0.0033	0.65	90%	0.0647		
South Truck/Rail Loadout	196	0.0033	0.65	90%	0.0647		
North Truck/Rail Loadout	196	0.0033	0.65	90%	0.0647		
Whole Corn Truck Sidedraw (B4 or B5)	280	0.0033	0.92	90%	0.0924		
Whole Corn Truck Sidedraw (B6 or B7)	280	0.0033	0.92	90%	0.0924		
Ground Corn Truck Loadout (O1)	56	0.0033	0.18	90%	0.0185		
Ground Corn Truck Loadout (O2)	56	0.0033	0.18	90%	0.0185		
Ground Corn Truck Loadout (O3)	56	0.0033	0.18	90%	0.0185		
Ground Corn Truck Loadout (O4)	56	0.0033	0.18	90%	0.0185		
Ground Corn Truck Loadout (O5)	56	0.0033	0.18	90%	0.0185		
Ground Corn Truck Loadout (O6)	56	0.0033	0.18	90%	0.0185		
Grinder Leg Truck Loadout	126	0.0033	0.42	90%	0.0416		
Totals			**5.96**	**-**	**0.5960**		

[1] Emission factor from AP-42, Chapter 9, Sections 9.9.1-1 and 9.9.1-2.

[2] Control efficiencies taken from existing facility permit. Truck receiving control efficiency based on use of choke feeding, whereas rail receiving is based upon use of choke feeding and side rails of hopper bottom rail, which effectively serve as a shroud. Grain handling control efficiency based upon use of enclosures and mineral oil application. Hammermill control efficiency based upon use of mineral oil. Grain shipping control efficiency based upon use of mineral oil

[3] Truck receiving cannot occur at same time as rail receiving due to shared handling equipment. South Green Train Pit and Shuttle Train Pit cannot be operated at the same time due to shared track and receiving pit alignment.

[4] Hourly throughput based on permitted limits. Existing permit limits truck receiving to 20,000 bushels (560 tons) per hour. Assumed 50 percent of throughput total from North Green Truck Pit and remaing 50 percent from South Green Truck Pit

Gavilon Grain, LLC - Burley
Existing Facility PM10 Emissions

Emission Unit Description	Hourly Throughput	PM_{10} Emission Factor[1]	Uncontrolled Emission Rate	Control Efficiency[2]	Controlled PM_{10} Emissions	LImited Annual Throughput	Limited PM_{10} Emissions
	(tons/hr)	(lb/ton)	(lbs/hr)	%	(lbs/hr)	(tons/yr)	(tons/yr)
	A	B	C=A*B	D	E=C*(1-E)	F	G=B*F*(1-E)/2000
Receiving							
South Green Train Pit	350	0.0025	0.88	95%	0.0438	700,000	0.1750
North Green Truck Pit[3]	280	0.0025	0.70	80%	0.1400		
South Green Truck Pit[3]	280	0.0025	0.70	80%	0.1400		
Shuttle Train Pit (feeds north and/or south Gray Leg)	952	0.0025	2.38	95%	0.1190		
Maximum Totals[4]			**2.38**	**-**	**0.2800**		
Handling							
North Green Distribution Leg	350	0.0340	11.90	100%	0.0000	700,000	0
South Green Distribution Leg	350	0.0340	11.90	100%	0.0000		
North Gray Shuttle Leg	476	0.0340	16.18	100%	0.0000		
South Gray Shuttle Leg	476	0.0340	16.18	100%	0.0000		
Totals			**56.17**	**-**	**0.0000**		
Storage							
Bin 1	172	0.0063	1.08	90%	0.1084	700,000	0.22
Bin 2	172	0.0063	1.08	90%	0.1084		
Bin 3	172	0.0063	1.08	90%	0.1084		
Bin 4	172	0.0063	1.08	90%	0.1084		
Bin 5	172	0.0063	1.08	90%	0.1084		
Bin 6	172	0.0063	1.08	90%	0.1084		
Bin 7	172	0.0063	1.08	90%	0.1084		
Bin A	47	0.0063	0.29	90%	0.0294		
Bin B	47	0.0063	0.29	90%	0.0294		
Bin C	47	0.0063	0.29	90%	0.0294		
Totals			**8.47**	**-**	**0.8467**		
Milling							
Hammermill #1 (Baghouse)	40	0.0120	0.48	20%	0.3840	602,000	2.89
Hammermill #2 (Baghouse)	40	0.0120	0.48	20%	0.3840		
Hammermill #3 (Baghouse)	40	0.0120	0.48	20%	0.3840		
Hammermill #4 (Cyclone)	14	0.0335	0.47	20%	0.3752	98,000	1.31
Hammermill #5 (Cyclone)	14	0.0335	0.47	20%	0.3752		
Totals			**2.38**	**-**	**1.9024**		

Gavilon Grain, LLC - Burley
Existing Facility PM10 Emissions

Shipping							
Bin B-A Truck Drop Pipe	196	0.0008	0.16	90%	0.0157	700,000	0.028
Bin B-C Truck Drop Pipe	196	0.0008	0.16	90%	0.0157		
South Truck/Rail Loadout	196	0.0008	0.16	90%	0.0157		
North Truck/Rail Loadout	196	0.0008	0.16	90%	0.0157		
Whole Corn Truck Sidedraw (B4 or B5)	280	0.0008	0.22	90%	0.0224		
Whole Corn Truck Sidedraw (B6 or B7)	280	0.0008	0.22	90%	0.0224		
Ground Corn Truck Loadout (O1)	56	0.0008	0.04	90%	0.0045		
Ground Corn Truck Loadout (O2)	56	0.0008	0.04	90%	0.0045		
Ground Corn Truck Loadout (O3)	56	0.0008	0.04	90%	0.0045		
Ground Corn Truck Loadout (O4)	56	0.0008	0.04	90%	0.0045		
Ground Corn Truck Loadout (O5)	56	0.0008	0.04	90%	0.0045		
Ground Corn Truck Loadout (O6)	56	0.0008	0.04	90%	0.0045		
Grinder Leg Truck Loadout	126	0.0008	0.10	90%	0.0101		
Totals			**1.44**	**-**	**0.1445**		

[1] Emission factor from AP-42, Chapter 9, Sections 9.9.1-1 and 9.9.1-2.

[2] Control efficiencies taken from existing facility permit. Truck receiving control efficiency based on use of choke feeding, whereas rail receiving is based upon use of choke feeding and side rails of hopper bottom rail, which effectively serve as a shroud. Grain handling control efficiency based upon use of enclosures and mineral oil application. Hammermill control efficiency based upon use of mineral oil. Grain shipping control efficiency based upon use of mineral oil

[3] Truck receiving cannot occur at same time as rail receiving due to shared handling equipment. South Green Train Pit and Shuttle Train Pit cannot be operated at the same time due to shared track and receiving pit alignment.

[4] Hourly throughput based on permitted limits. Existing permit limits truck receiving to 20,000 bushels (560 tons) per hour. Assumed 50 percent of throughput total from North Green Truck Pit and remaing 50 percent from South Green Truck Pit

Gavilon Grain, LLC - Burley
Existing Facility PM2.5 Emissions

Emission Unit Description	Maximum Hourly Throughput	$PM_{2.5}$ Emission Factor[1]	Uncontrolled Emission Rate	Control Efficiency[2]	Controlled $PM_{2.5}$ Emissions	LImited Annual Throughput	Limited $PM_{2.5}$ Emissions
	(tons/hr)	(lb/ton)	(lbs/hr)	%	(lbs/hr)	(tons/yr)	(tons/yr)
	A	B	C=A*B/2000	D	E=C*(1-E)		
Receiving							
South Green Train Pit	350	0.0004	0.15	95%	0.0074	700,000	0.0298
North Green Truck Pit[3]	280	0.0004	0.12	80%	0.0238		
South Green Truck Pit[3]	280	0.0004	0.12	80%	0.0238		
Shuttle Train Pit (feeds north and/or south Gray Leg)	952	0.0004	0.40	95%	0.0202		
Maximum Totals[4]			**0.40**	**-**	**0.0476**		
Handling							
North Green Distribution Leg	350	0.0058	2.02	100%	0.0000	700,000	0.0000
South Green Distribution Leg	350	0.0058	2.02	100%	0.0000		
North Gray Shuttle Leg	476	0.0058	2.75	100%	0.0000		
South Gray Shuttle Leg	476	0.0058	2.75	100%	0.0000		
Totals			**4.05**	**-**	**0.0000**		
Storage							
Bin 1	172	0.0011	0.18	90%	0.0184	700,000	0.0375
Bin 2	172	0.0011	0.18	90%	0.0184		
Bin 3	172	0.0011	0.18	90%	0.0184		
Bin 4	172	0.0011	0.18	90%	0.0184		
Bin 5	172	0.0011	0.18	90%	0.0184		
Bin 6	172	0.0011	0.18	90%	0.0184		
Bin 7	172	0.0011	0.18	90%	0.0184		
Bin A	47	0.0011	0.05	90%	0.0050		
Bin B	47	0.0011	0.05	90%	0.0050		
Bin C	47	0.0011	0.05	90%	0.0050		
Totals			**1.44**	**-**	**0.1439**		
Milling							
Hammermill #1 (Baghouse)	40	0.0020	0.08	20%	0.0653	602,000	0.4912
Hammermill #2 (Baghouse)	40	0.0020	0.08	20%	0.0653		
Hammermill #3 (Baghouse)	40	0.0020	0.08	20%	0.0653		
Hammermill #4 (Cyclone)	14	0.0057	0.08	20%	0.0638	98,000	0.2232
Hammermill #5 (Cyclone)	14	0.0057	0.08	20%	0.0638		
Totals			**0.40**	**-**	**0.3234**		

Gavilon Grain, LLC - Burley
Existing Facility PM2.5 Emissions

Shipping							
Bin B-A Truck Drop Pipe	196	0.000136	0.03	90%	0.0027	700,000	0.0048
Bin B-C Truck Drop Pipe	196	0.000136	0.03	90%	0.0027		
South Truck/Rail Loadout	196	0.000136	0.03	90%	0.0027		
North Truck/Rail Loadout	196	0.000136	0.03	90%	0.0027		
Whole Corn Truck Sidedraw (B4 or B5)	280	0.000136	0.04	90%	0.0038		
Whole Corn Truck Sidedraw (B6 or B7)	280	0.000136	0.04	90%	0.0038		
Ground Corn Truck Loadout (O1)	56	0.000136	0.01	90%	0.0008		
Ground Corn Truck Loadout (O2)	56	0.000136	0.01	90%	0.0008		
Ground Corn Truck Loadout (O3)	56	0.000136	0.01	90%	0.0008		
Ground Corn Truck Loadout (O4)	56	0.000136	0.01	90%	0.0008		
Ground Corn Truck Loadout (O5)	56	0.000136	0.01	90%	0.0008		
Ground Corn Truck Loadout (O6)	56	0.000136	0.01	90%	0.0008		
Grinder Leg Truck Loadout	126	0.000136	0.02	90%	0.0017		
Total Shipping			**0.25**	**-**	**0.0246**		

[1] Emission factors from AP-42, Chapter 9, Tables 9.9.1-1 and 9.9.1-2. Since Table 9.9.1-2 does not provide PM2.5 emissions, Gavilon utilized PM2.5 scaling fraction of 17 percent from footnote 'g' of AP-42, Table 9.9.1-1 to scale PM10 emissions to PM2.5 emissions.

[2] Control efficiencies taken from existing facility permit. Truck receiving control efficiency based on use of choke feeding, whereas rail receiving is based upon use of choke feeding and side rails of hopper bottom rail, which effectively serve as a shroud. Grain handling control efficiency based upon use of enclosures and mineral oil application. Hammermill control efficiency based upon use of mineral oil. Grain shipping control efficiency based upon use of mineral oil

[3] Truck receiving cannot occur at same time as rail receiving due to shared handling equipment. South Green Train Pit and Shuttle Train Pit cannot be operated at the same time due to shared track and receiving pit alignment.

[4] Hourly throughput based on permitted limits. Existing permit limits truck receiving to 20,000 bushels (560 tons) per hour. Assumed 50 percent of throughput total from North Green Truck Pit and remaing 50 percent from South Green Truck Pit

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

M E M O R A N D U M

DATE: April 20, 2018

TO: Morrie Lewis, Permit Writer, Air Program

FROM: Thomas Swain, Air Quality Modeler, Analyst 3, Air Program

PROJECT: Gavilon Grain, LLC dba Peavey Company in Burley, Idaho, a Permit to Construct (PTC) P-2009.0091, Project 61970, Facility ID No. 031-00038

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

1.0 Summary

Gavilon Grain (Gavilon) submitted an application for a Permit to Construct (PTC) on December 11, 2017, for a modification to an existing facility located in Burley, Idaho, denoted as PTC P-2009.00911 Project 61970.

Gavilon operates a grain elevator and animal feed manufacturing facility in Burley, Idaho. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. The processes include use of receiving pits, grain distribution legs, hammermills, conveyors, screw augers, storage bins, and storage piles. Grain is received mostly by railcar, although some arrives by truck. The grain is unloaded into below-grade pits and then treated with edible mineral oil to control dust during the handling process. The grain is transported by conveyors to various destinations within the facility. Grinding is done with hammermills, and grinding emissions are controlled by cyclones and baghouses. The processed grain is stored in silos until shipment.

The PTC application was submitted for construction of a new corn steam flaking mill. Gavilon plans on installing new (enclosed) draw spouts to existing storage bins. These spouts convey corn to the new Flaking System Transfer Leg. This Leg is an enclosed bucket elevator which moves the corn to a new conveyor and a new Flaker System storage bin. The corn is them moved to another area where the corn is cleaned, refined, and eventually dropped into the flaking steam chamber, where a new boiler is used to treat the grain with the proper amount of moisture before being fed into the flaking mill rollers. Here the corn is rolled into flakes and dried. The final product is then stored before sale.

Details of the entire process are discussed in the main body of the DEQ Statement of Basis supporting the issued proposed PTC. This modeling review memorandum provides a summary and approval of the ambient air impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification analyses, additional clarifications, and conclusions.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard as required by IDAPA 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

NAQS Environmental Experts (NAQS), performed the ambient air impact analyses for this project on behalf of Gavilon. The analyses were performed to demonstrate compliance with applicable air quality standards. The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that the estimated emission increases at the facility associated with the proposed project will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. Evaluation of emissions estimates is the responsibility of the permit writer and is addressed in the main body of the Statement of Basis. The accuracy of emissions estimates was not evaluated as part of DEQ's review of the air impact analyses submitted and described in this modeling review memorandum.

A modeling protocol was submitted for this project on August 11, 2017. After the submittal, NAQS contacted DEQ with some modifications to the information as listed in the protocol and supplied those data in an email dated August 13, 2017. DEQ sent a letter approving the protocol, with conditions, on August 23, 2017. NAQS submitted a 15-day pre-permit construction PTC application on November 13, 2017. It was denied on November 22, 2017 due to several items, including omission of estimates of non-HAP TAP emissions. Gavilon re-submitted the application on December 11, 2017. DEQ responded on January 10, 2018, with a letter of incompleteness. Items in the incompleteness letter included several modeling items: 1) the treatment of the release heights of open door volume sources was inconsistent with DEQ modeling guidance, and 2) assessment of transportation scenarios was different than utilized with the previous application. NAQS responded with another submittal on February 9. 2018. The application was deemed complete on March 9, 2018.

The final submitted air quality impact analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a National Ambient Air Quality Standards (NAAQS) compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W - *Guideline on Air Quality Models* (Appendix W). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department that operation of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
General Emissions Rates. Emission rates used in the modeling analyses, as listed in this memorandum, represent maximum potential emissions for the applicable averaging period as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses. Most of the sources, including the new boiler, had emission rates modeled at 8,760 hours a year to determine annual modeled impacts. The hammermills, truck drops, and produce loadouts were modeled at 13 hours a day and compliance with NAAQS has not been demonstrated for longer operational periods.
Modeling Thresholds for Criteria Pollutant Emissions. Maximum short-term and long-term emissions of the criteria pollutants PM_{10}, $PM_{2.5}$, and NO_2 associated with the proposed project are above the Level 1 Modeling Applicability Threshold for each pollutant. Therefore, a demonstration of compliance with NAAQS was done for these criteria pollutants and applicable averaging times.	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutants having an emission increase that is greater than Level I Modeling Applicability Thresholds or for pollutant increases above BRC thresholds (where the pollutant-specific BRC modeling exemption can be used). Compliance with NAAQS has not been demonstrated for emissions that exceed the emission estimates presented in the application.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
TAPS Modeling. Emission rates of four TAPs, Nickel, Formaldehyde, Cadmium, and Arsenic, exceeded Emissions Screening Level (EL) rates of Idaho Air Rules Section 585 and 586.	Air impact analyses demonstrating compliance with TAPS, as required by Idaho Air Rules Section 203.03, is required for pollutants having an emissions rate greater than ELs. Because several TAP emissions exceeded the ELs, a demonstration of compliance with TAPs increments was required.
NO_2/NO_x Ratio Methodology – The default ARM2 (Tier 2 Ambient Ratio Method Version 2) was used to address NO_x chemistry.	Compliance has not been demonstrated for use of NO_2/NO_x chemistry methods other than ARM2 with a default Minimum Ambient Ratio of 0.5.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

Gavilon operates a grain elevator and animal feed manufacturing facility in Burley, Idaho. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. This PTC is being submitted for construction of a new corn steam flaking mill.

Air impact analyses performed by NAQS, as part of the permit application, were submitted to show that facility-wide emissions do not cause or contribute to an exceedance of any NAAQS or TAP Acceptable Ambient Concentrations(AAC) or Acceptable Ambient Concentration of Carcinogen(AACC).

2.2 Proposed Location and Area Classification

Gavilon is located in Cassia County, Idaho, with approximate UTM location of 4713975 N and 269706 E. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Criteria Pollutant and TAP Impact Analyses for a PTC are addressed in Idaho Air Rules Sections 203.02 and 203.03:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS**. The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*

__03. Toxic Air Pollutants.__ Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

__Estimates of Ambient Concentrations__. All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted using methods and data as outlined in Appendix W. Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

DEQ has developed modeling applicability thresholds that effectively assure that project-related emission increases below stated values will result in ambient air impacts below the applicable SILs. The threshold levels and dispersion modeling analyses supporting those levels are presented in the *State of Idaho Guideline for Performing Air Quality Impact Analyses*[1] (Idaho Air Modeling Guideline). Use of a modeling threshold represents the use of conservative modeling, performed in support of the threshold, as a project SIL analysis. Project-specific modeling applicability for this project is addressed in Section 3.1.1 of this memorandum.

If modeled maximum pollutant impacts to ambient air from the emission sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from facility-wide emissions, and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. If the SIL analysis indicates the facility/modification has an impact exceeding the SIL, then the facility might not have a significant contribution to a violation if impacts are below the SIL at the specific receptors showing the violations during the specific time periods when a modeled violation occurred.

Table 2. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Impact Levels[a] (μg/m^3)[b]	Regulatory Limit[c] (μg/m^3)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 μg/m^3)	75 ppb[p] (196 μg/m^3)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 μg/m^3)	100 ppb[s] (188 μg/m^3)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	70 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or b) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or c) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Idaho Air Rules Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emissions Source Data

Emissions rates of TAPS and criteria pollutants for the project were provided by the applicant for various applicable averaging periods. Review and approval of estimated emissions was the responsibility of the DEQ permit writer and is not addressed in this modeling memorandum. DEQ modeling review included verification that the application's potential emissions rates were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses submitted by NAQS, as listed in this memorandum, should be reviewed by the DEQ permit writer against those in the emissions inventory of the permit application. All modeled criteria air pollutant emissions rates should be equal to or greater than the facility's emissions calculated in other sections of the PTC application or requested permit allowable emission rates.

3.1.1 Criteria Pollutant Emissions Rates and Modeling Applicability

If the modification-related or facility-wide potential to emit (PTE) values for a specific criteria pollutant would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for some pollutants exceeding BRC thresholds, then an air impact analysis for that pollutant may not be required for permit issuance. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules (Policy on NAAQS Compliance Demonstration Requirements, DEQ policy memorandum, July 11, 2014) is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant." The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analysis is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

DEQ has generated non-site-specific project modeling thresholds for those projects that cannot use the BRC exemption from an impact analysis (if there are specific permitted emissions limits that require changing, etc.). Modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[1]. These thresholds were based on assuring an ambient impact of less than the established SIL for that specific pollutant and averaging period.

If project-specific total emissions rates are below Level I Modeling Applicability Thresholds, project-specific air impact analyses are not necessary for permitting. Uses of Level II Modeling Applicability Thresholds are conditional, requiring DEQ approval. Table 3 provides the emissions-based modeling applicability summary. The submitted application did not evaluate estimated emissions increases against BRC thresholds, as the project involves an increase in permit-allowable throughput. Therefore, a permit modification would be needed regardless of the magnitude of the emissions increase, and a BRC exemption could not be used for the project. The submitted modeling report evaluated modeling applicability based on comparison of emissions to Level I Modeling Applicability Thresholds. Emissions of the criteria pollutants PM_{10}, $PM_{2.5}$, and NO_2 resulting from the proposed project are greater than the Level 1 Modeling Applicability Thresholds, and therefore air impact analyses are required for these criteria pollutants. Modeled emission rates for these pollutants for all "project" sources are listed in Table 4. The facility wide emissions, as modeled to demonstrate compliance with all NAAQS, are listed in Table 5.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NO_x, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O_3 impacts resulting from VOC and NO_x emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Com munity Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Table 3. MODELING APPLICABILITY ANALYSIS RESULTS

Pollutant	Averaging Period	Emissions	BRC Threshold[a] (ton/year)	Level I Modeling Thresholds (lb/hour or ton/year)	Level II Modeling Thresholds (lb/hour or ton/year)	Modeling Required
$PM_{2.5}$	Annual	0.80 ton/yr[b]	1.0	0.350	4.1	Yes
	24-hour	0.2 lb/hr[c]		0.054	0.63	Yes
PM_{10}	24-hour	0.7 lb/hr[c]	1.5	0.22	2.6	Yes
NO_x	Annual	7.0 ton/yr[b]	4.0	1.2	14	Yes
	1-hour	1.61 lb/hr[c]		0.2	2.4	Yes
SO_2	Annual	0.1 ton/yr[b]	4.0	1.2	14	No
	1-hour	0.02 lb/hr[c]		0.21	2.5	No
CO	1,8 hour	0.6 lb/hr[c]	10.0	15	175	No
Lead	Annual	< 0.01 lb/mo[d]	0.06	14 pounds/month		No

a. No criteria pollutant emissions increases could qualify for a BRC exemption.
b. Tons/year.
c. Pounds/hour.
d Pounds/month

Addressing secondary formation of O_3 has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

Allowable emissions estimates of VOCs and NO_x are below the 100 tons/year threshold, and DEQ determined it was not appropriate or necessary to require a quantitative source specific O_3 impact analysis.

TABLE 4 Modeled Criteria Pollutants for SIL Analysis					
Source ID	**Description**	**PM_{10} (lb/hr)[a]**	**$PM_{2.5}$ (lb/hr)**	**$PM_{2.5}$ANN (lb/hr)**	**NO_2 (lb/hr)**
B1	Boiler Flaking System	0.08000	0.08000	0.07991	1.61
FL1	Flaker Cooler Cyclone	0.01000	0.00044	0.00044	
BIN11_V1	Bin 11	0.02250	0.00500	0.00400	
BIN11_V2	Bin 11	0.02250	0.00500	0.00400	
BIN11_V3	Bin 11	0.02250	0.00500	0.00400	
BIN11_V4	Bin 11	0.02250	0.00500	0.00400	
CL1	Rotary Grain Cleaner	0.48000	0.08000	0.08219	
DOOR1	Flake Storage barn Door	0.01010	0.00153	0.00153	
DOOR2	Flake Storage barn Door	0.01010	0.00153	0.00153	
CL2	Drop Removed FM to Storage	0.01428	0.00244	0.00244	

TABLE 5 Modeled Criteria Pollutants					
Source ID	**Description**	**PM10[a] (lb/hr)[e]**	**PM25[b] (lb/hr)[e]**	**PM25ANN[c] (lb/hr)[e]**	**NO2[d] (lb/hr)[e]**
B1	Boiler Flaking System	0.08000	0.08000	0.07991	1.61
FL1	Flaker Cooler Cyclone	0.01000	0.00044	0.00044	
BIN11_V1	Bin 11	0.02250	0.00500	0.00400	
BIN11_V2	Bin 11	0.02250	0.00500	0.00400	
BIN11_V3	Bin 11	0.02250	0.00500	0.00400	
BIN11_V4	Bin 11	0.02250	0.00500	0.00400	
M1	Baghouse - Hammermill 1	0.38413	0.06528	0.06895	
M2	Baghouse - Hammermill 2	0.38413	0.06528	0.06895	
M3	Baghouse - Hammermill 3	0.38413	0.06528	0.06895	
M4	Cyclone - Hammermill 4	0.37520	0.06378	0.04703	
M5	Cyclone - Hammermill 5	0.37520	0.06378	0.04703	
B1_VENT1	Bin 1	0.02706	0.00461	2.14E-04	
B1_VENT2	Bin 1	0.02706	0.00461	2.14E-04	
B1_VENT3	Bin 1	0.02706	0.00461	2.14E-04	
B1_VENT4	Bin 1	0.02706	0.00461	2.14E-04	
B2_VENT1	Bin 2	0.02706	0.00461	2.14E-04	
B2_VENT2	Bin 2	0.02706	0.00461	2.14E-04	
B2_VENT3	Bin 2	0.02706	0.00461	2.14E-04	
B2_VENT4	Bin 2	0.02706	0.00461	2.14E-04	
B3_VENT1	Bin 3	0.02706	0.00461	2.14E-04	
B3_VENT2	Bin 3	0.02706	0.00461	2.14E-04	
B3_VENT3	Bin 3	0.02706	0.00461	2.14E-04	
B3_VENT4	Bin 3	0.02706	0.00461	2.14E-04	

TABLE 5 Modeled Criteria Pollutants					
Source ID	**Description**	**PM10[a] (lb/hr)[e]**	**PM25[b] (lb/hr)[e]**	**PM25ANN[c] (lb/hr)[e]**	**NO2[d] (lb/hr)[e]**
B4_VENT1	Bin 4	0.01810	0.00307	1.43E-04	
B4_VENT2	Bin 4	0.01810	0.00307	1.43E-04	
B4_VENT3	Bin 4	0.01810	0.00307	1.43E-04	
B4_VENT4	Bin 4	0.01810	0.00307	1.43E-04	
B4_VENT5	Bin 4	0.01810	0.00307	1.43E-04	
B4_VENT6	Bin 4	0.01810	0.00307	1.43E-04	
B5_VENT1	Bin 5	0.01810	0.00307	1.43E-04	
B5_VENT2	Bin 5	0.01810	0.00307	1.43E-04	
B5_VENT3	Bin 5	0.01810	0.00307	1.43E-04	
B5_VENT4	Bin 5	0.01810	0.00307	1.43E-04	
B5_VENT5	Bin 5	0.01810	0.00307	1.43E-04	
B5_VENT6	Bin 5	0.01810	0.00307	1.43E-04	
B6_VENT1	Bin 6	0.01810	0.00307	1.43E-04	
B6_VENT2	Bin 6	0.01810	0.00307	1.43E-04	
B6_VENT3	Bin 6	0.01810	0.00307	1.43E-04	
B6_VENT4	Bin 6	0.01810	0.00307	1.43E-04	
B6_VENT5	Bin 6	0.01810	0.00307	1.43E-04	
B6_VENT6	Bin 6	0.01810	0.00307	1.43E-04	
B7_VENT1	Bin 7	0.01810	0.00307	1.43E-04	
B7_VENT2	Bin 7	0.01810	0.00307	1.43E-04	
B7_VENT3	Bin 7	0.01810	0.00307	1.43E-04	
B7_VENT4	Bin 7	0.01810	0.00307	1.43E-04	
B7_VENT5	Bin 7	0.01810	0.00307	1.43E-04	
B7_VENT6	Bin 7	0.01810	0.00307	1.43E-04	
BA_VENT1	Bin A	0.01468	0.00252	4.28E-04	
BA_VENT2	Bin A	0.01468	0.00252	4.28E-04	
BB_VENT1	Bin B	0.01468	0.00252	4.28E-04	
BB_VENT2	Bin B	0.01468	0.00252	4.28E-04	
BC_VENT1	Bin C	0.01468	0.00252	4.28E-04	
BC_VENT2	Bin C	0.01468	0.00252	4.28E-04	
CL1	Rotary Grain Cleaner	0.48000	0.08000	0.08219	
DOOR1	Flake Storage barn Door	0.01010	0.00153	0.00153	
DOOR2	Flake Storage barn Door	0.01010	0.00153	0.00153	
CL2	Drop Removed FM to Storage	0.01428	0.00244	0.00244	
GR2[f]	South Green Train Pit	0.04379	0.00740	0.00680	
GR3[f]	North Green Truck Pit	0.14000	0.02380	0.00340	
GR4[f]	South Green Truck Pit	0.14000	0.02380	0.00340	
GR5[f]	Grey Shuttle Train Pit	0.11900	0.20200	0.00680	
SH1	Bin B-A Truck Drop	0.01571	0.00267	1.54E-04	

TABLE 5 Modeled Criteria Pollutants					
Source ID	**Description**	**PM10[a] (lb/hr)[e]**	**PM25[b] (lb/hr)[e]**	**PM25ANN[c] (lb/hr)[e]**	**NO2[d] (lb/hr)[e]**
SH2	Bin B-C Truck Drop	0.01571	0.00267	1.54E-04	
SH3	South Green Truck/Rail Loadout	0.01571	0.00267	1.54E-04	
SH4	South Green Truck/Rail Loadout	0.01571	0.00267	1.54E-04	
SH5_B4	Whole Corn Truck Sidedraw	0.02240	0.00381	1.54E-04	
SH5_B5	Whole Corn Truck Sidedraw	0.02240	0.00381	1.54E-04	
SH5_B6	Whole Corn Truck Sidedraw	0.02240	0.00381	1.54E-04	
SH5_B7	Whole Corn Truck Sidedraw	0.02240	0.00381	1.54E-04	
SH6_01	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	
SH6_02	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	
SH6_03	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	
SH6_04	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	
SH7	Grinder Leg Truck	0.01010	0.00171	1.54E-04	
SH6_05	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	
SH6_06	Ground Corn Truck Loadout	0.00448	7.60E-04	1.54E-04	

[a] emissions modeled for 24 hour average PM_{10} NAAQS
[b] emissions modeled for 24 hour average $PM_{2.5}$ NAAQS
[c] emissions modeled for annual average $PM_{2.5}$ NAAQS
[d] emissions modeled for 1 hour and annual NO_2 NAAQS
[e] Values are emissions in pounds per hour; all sources are modeled at 24 hours a day except for sources M1-M5, and SH1-SH7, which are modeled at 13 hours/day.
[f.] Three transportation scenarios were modeled separately: **1**) GR2; **2)** GR3 and GR4; **3**) GR5.

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NO_x, SO_2, and/or VOCs was assumed by DEQ to be negligible based on the magnitude of emissions and the short distance from emissions sources to modeled receptors where maximum PM_{10} and $PM_{2.5}$ impacts would be anticipated.

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 220 are only applicable for new or modified sources constructed after July 1, 1995. The submitted emissions inventory in the application identified four TAPs having potential emission increases that could exceed screening emissions levels (ELs) of Idaho Air Rules Section 585 or 586. Therefore, a modeling assessment of TAPS impacts was required. The modeled emission rates are shown in Table 6 below. All TAPS emissions are from source B1, the new Flake System Boiler.

Table 6. MODELED TAP EMISSIONS				
Source	**TAP**	**CAS Number**	**Emissions[a] (Pounds/Hour)**	**DEQ Screening Emissions Level (EL) (Pounds/Hour)**
B1	Arsenic	7440-38-2	3.35E-06	1.50E-06
	Cadmium	7440-43-9	1.84E-05	3.70E-06
	Formaldehyde	50-00-0	0.00126	5.10E-04
	Nickel	7440-02-0	3.52E-05	2.70E-05

a. Emissions are annual average rates since all TAPs are carcinogens and regulated on an annual basis.

3.1.3 Emission Release Parameters

Table 7 provides emissions release parameters for all facility point and volume type sources as used in the final modeling assessment. The parameters for point sources include stack height, stack diameter, exhaust temperature, and exhaust velocity. For volume sources, the parameters are release height, initial horizontal dimension, and initial vertical dimension.

Stack parameters used in the modeling analyses were documented / justified adequately in this application. As referenced in Section 1, the applicant originally assigned to sources DOOR1 and DOOR2 (open barn doors) a value for "release height" equal to the height of the open doors. Based on DEQ direction (and consistent with DEQ policy), NAQS revised these values in the final modeling analyses to a value equal to the mid-point door height of these sources.

Table 7. MODELING PARAMETERS							
Point Sources							
Source ID	**Description**	**Easting (X)[a] (m)**	**Northing (Y)[b] (m)**	**Stack Height (ft)[c]**	**Temp. (°F)[d]**	**Exit Velocity (fps)[e]**	**Stack Diameter (ft)[c]**
B1	Boiler Flaking System	269687.4	4713882	19.12	425.00	17.294	1.990
FL1	Flaker Cooler Cyclone	269669.5	4713880	39.25	190.00	61.725	3.708
BIN11_V1	Bin 11	269702.8	4713889	45.75	-459.7[f]	0.003[g]	1.500
BIN11_V2	Bin 11	269708.2	4713883	45.75	-459.7[f]	0.003[g]	1.500
BIN11_V3	Bin 11	269702.8	4713878	45.75	-459.7[f]	0.003[g]	1.500
BIN11_V4	Bin 11	269697.1	4713883	45.75	-459.7[f]	0.003[g]	1.500
M1	Baghouse - Hammermill 1	269703.5	4713991	14.01	80.01	49.049	1.509
M2	Baghouse - Hammermill 2	269703.5	4713991	14.01	80.01	49.049	1.509
M3	Baghouse - Hammermill 3	269693.8	4713996	14.01	80.01	49.049	1.509
M4	Cyclone - Hammermill 4	269703.3	4714007	20.01	80.01	14.140	1.509
M5	Cyclone - Hammermill 5	269703.3	4714007	20.01	80.01	14.140	1.509
B1_VENT1	Bin 1	269707	4714017	75.00	-459.7[f]	0.003[g]	1.706
B1_VENT2	Bin 1	269717.6	4714017	75.00	-459.7[f]	0.003[g]	1.706
B1_VENT3	Bin 1	269717.9	4714006	75.00	-459.7[f]	0.003[g]	1.706
B1_VENT4	Bin 1	269706	4714007	75.00	-459.7[f]	0.003[g]	1.706
B2_VENT1	Bin 2	269706.2	4713999	75.00	-459.7[f]	0.003[g]	1.706
B2_VENT2	Bin 2	269716.7	4713999	75.00	-459.7[f]	0.003[g]	1.706
B2_VENT3	Bin 2	269716.9	4713989	75.00	-459.7[f]	0.003[g]	1.706

Table 7. MODELING PARAMETERS							
Point Sources							
Source ID	**Description**	**Easting (X)[a] (m)**	**Northing (Y)[b] (m)**	**Stack Height (ft)[c]**	**Temp. (°F)[d]**	**Exit Velocity (fps)[e]**	**Stack Diameter (ft)[c]**
B2_VENT4	Bin 2	269705.8	4713989	75.00	-459.7[f]	0.003[g]	1.706
B3_VENT1	Bin 3	269705.8	4713980	75.00	-459.7[f]	0.003[g]	1.706
B3_VENT2	Bin 3	269716.4	4713979	75.00	-459.7[f]	0.003[g]	1.706
B3_VENT3	Bin 3	269716.6	4713969	75.00	-459.7[f]	0.003[g]	1.706
B3_VENT4	Bin 3	269705.3	4713969	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT1	Bin 4	269706.3	4713959	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT2	Bin 4	269718.1	4713959	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT3	Bin 4	269721.3	4713952	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT4	Bin 4	269718.4	4713945	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT5	Bin 4	269705.7	4713945	75.00	-459.7[f]	0.003[g]	1.706
B4_VENT6	Bin 4	269702.7	4713952	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT1	Bin 5	269706.9	4713936	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT2	Bin 5	269718.8	4713936	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT3	Bin 5	269721.9	4713929	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT4	Bin 5	269718.6	4713922	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT5	Bin 5	269706.5	4713922	75.00	-459.7[f]	0.003[g]	1.706
B5_VENT6	Bin 5	269703.4	4713929	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT1	Bin 6	269688.5	4714042	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT2	Bin 6	269698.7	4714042	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT3	Bin 6	269702.6	4714034	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT4	Bin 6	269699.8	4714028	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT5	Bin 6	269687.5	4714027	75.00	-459.7[f]	0.003[g]	1.706
B6_VENT6	Bin 6	269683.8	4714034	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT1	Bin 7	269687.3	4714020	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT2	Bin 7	269699.7	4714019	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT3	Bin 7	269702.5	4714012	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT4	Bin 7	269699.8	4714006	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT5	Bin 7	269686.8	4714006	75.00	-459.7[f]	0.003[g]	1.706
B7_VENT6	Bin 7	269683.8	4714012	75.00	-459.7[f]	0.003[g]	1.706
BA_VENT1	Bin A	269721.1	4714009	39.99	-459.7[f]	0.003[g]	1.706
BA_VENT2	Bin A	269721.2	4714005	39.99	-459.7[f]	0.003[g]	1.706
BB_VENT1	Bin B	269722.6	4713997	39.99	-459.7[f]	0.003[g]	1.706
BB_VENT2	Bin B	269720.5	4713993	39.99	-459.7[f]	0.003[g]	1.706
BC_VENT1	Bin C	269718.7	4713971	39.99	-459.7[f]	0.003[g]	1.706
BC_VENT2	Bin C	269720.6	4713966	39.99	-459.7[f]	0.003[g]	1.706

Table 7. MODELING PARAMETERS						
Volume Sources						
Source ID	**Source Description**	**Easting (X)[a] (m)**	**Northing (Y)[b] (m)**	**Release Height (ft)[c]**	**Initial Horizontal Dimension (ft)[c]**	**Initial Vertical Dimension (ft)[c]**
CL1	Rotary Grain Cleaner	269689.8	4713884	85.00	1.86	37.21
DOOR1	Flake Storage Barn Door	269634.8	4713900	8.50	2.79	3.95
DOOR2	Flake Storage barn Door	269666.3	4713900	8.50	2.79	3.95
CL2	Drop Removed FM to Storage	269692.8	4713886	4.00	1.16	1.86
GR2	South Green Train Pit	269737.2	4713963	20.01	13.29	18.60
GR3	North Green Truck Pit	269730.7	4714003	37.50	19.00	34.88
GR4	South Green Truck Pit	269730.7	4713963	37.50	14.21	34.88
GR5	Grey Shuttle Train Pit	269736.9	4713954	20.01	13.29	18.60
SH1	Bin B-A Truck Drop	269724.1	4714007	37.50	18.44	34.88
SH2	Bin B-C Truck Drop	269724.3	4713968	37.50	14.21	34.88
SH3	South Green Truck/Rail Loadout	269731.8	4713979	37.50	18.44	34.88
SH4	South Green Truck/Rail Loadout	269731.8	4713992	37.50	18.44	34.88
SH5_B4	Whole Corn Truck Sidedraw	269721.2	4713952	37.50	14.21	34.88
Volume Sources						
Source ID	**Source Description**	**Easting (X)[a] (m)**	**Northing (Y)[b] (m)**	**Release Height (ft)[c]**	**Initial Horizontal Dimension (ft)[c]**	**Initial Vertical Dimension (ft)[c]**
SH5_B5	Whole Corn Truck Sidedraw	269721.8	4713929	37.50	14.21	34.88
SH5_B6	Whole Corn Truck Sidedraw	269683.9	4714034	37.50	18.44	34.88
SH5_B7	Whole Corn Truck Sidedraw	269684.2	4714013	37.50	18.44	34.88
SH6_01	Ground Corn Truck Loadout	269727.3	4714014	30.02	15.09	27.92
SH6_02	Ground Corn Truck Loadout	269727.5	4714021	30.02	15.09	27.92
SH6_03	Ground Corn Truck Loadout	269727.5	4714027	30.02	15.09	27.92
SH6_04	Ground Corn Truck Loadout	269727.6	4714032	30.02	15.09	27.92
SH7	Grinder Leg Truck	269685.6	4714002	37.50	18.44	34.88
SH6_05	Ground Corn Truck Loadout	269727.5	4714038	30.02	15.09	27.92
SH6_06	Ground Corn Truck Loadout	269727.5	4714044	30.02	15.09	27.92

a. Universal Transverse Mercator coordinates in meters in the east/west direction.
b. Universal Transverse Mercator coordinates in meters in the north/south direction.
c. Feet.
d. Temperature in degrees Fahrenheit.
e. Feet/second.
f. Set at 0 Kelvin (-459.7 ^{o}F) to signal the model to set the temperature equal to the ambient temperature. This is done to eliminate thermal buoyancy of the plume.
g. Set at a minimal value to eliminate momentum induced plume rise (per capped release sources).

3.2 Background Concentrations

Background concentrations were obtained from NW-AIRQUEST[2], based on the coordinates of the center of the facility. Because the facility emissions exceeded the Level I Modeling Applicability Thresholds for PM_{10}, $PM_{2.5}$, and NO_2, compliance demonstration modeling utilizing these background data were required. These data are listed in Table 10, *Results for NAAQS Impact Analyses*,

3.3 Impact Modeling Methodology

This section describes the modeling methods used by the applicant to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Analyses

NAQS performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the proposed facility as described in the application. DEQ did independent assessment modeling analyses to determine that compliance with NAAQS was achieved. NAQS looked at three separate scenarios for modeling transfer options: 1) truck receiving only with the North Green Truck Pit (GR3) and the South Green Truck Pit (GR4) operating simultaneously; 2) receiving at the Grey Shuttle Train Pit (GR5) only; and 3) receiving at the South Green Train Pit (GR2) only. It was determined in the process of modeling analyses that GR1, identified as the North Green Train Pit in prior applications, no longer exists. Maximum design concentrations for PM occur when modeling the emissions from scenario 1.

Results of the submitted analyses demonstrate compliance with applicable air quality standards to DEQ’s satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 8 provides a brief description of parameters used in the modeling analyses.

Table 8. MODELING PARAMETERS

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Cassia County, Idaho	The facility is located in an area that is attainment or unclassified for all criteria air pollutants
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 16216r
Meteorological Data	2011-2016 surface data from Burley Municipal Airport and upper air data from Boise, ID	See Section 3.3.4 for a detailed discussion on the meteorological data.
Terrain	Considered	See Section 5.3 below.
Building Downwash	Considered	Because buildings are present at the Gavilon, BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1 Grid 2 Grid 3 Grid 4	25-meter spacing out to distances of 900 meters with respect to the facility 50-meter spacing out to approximately 1400 meters 100- meter spacing out to 2400 meters 250 and 500–meter spacing out to 5400 meters and 7400 meters

3.3.2 Modeling Protocol and Methodology

A modeling protocol was submitted for this project on August 11, 2017. NAQS submitted a 15-day pre-permit construction PTC application on November 13, 2017. It was denied on November 22, 2017, due to several items, including omission of estimates of non-HAP TAP emissions. Gavilon resubmitted the application on December 11, 2017. DEQ responded on January 10, 2018 with a letter of incompleteness. NAQS responded with another submittal on February 9. 2018. The application was deemed complete on March 9, 2018.

DEQ revised the submitted “modeled” annual emission rates to reflect the annual capacities as listed in the application for sources M1-M5 and SH1-SH7. These sources are limited to 13 hours per day of operation. The annual $PM_{2.5}$ emissions as supplied were increased by a factor of 24/13 (hours) to accurately match the requested annual throughput limits. Therefore, the annual $PM_{2.5}$ impacts listed is this document are larger than those as shown in the application, but still comply with all NAAQS.

Project-specific modeling and other required impact analyses were generally conducted using data and methods discussed in pre-application correspondence and in the *Idaho Air Quality Modeling Guideline*[1].

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight-line trajectory of ISCST3, but it includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 16216r was used by the applicant for the air impact modeling analyses to evaluate impacts of the facility. This version is the current version at the time the application was received by DEQ.

3.3.4 Meteorological Data

NAQS used meteorological data collected at the Burley Municipal Airport for the period 2011-2016. Upper air data were taken from the Boise, Idaho, airport. The year 2013 was not utilized due to significant periods of missing data. DEQ supplied these data and determined the meteorological data used in the submitted analyses were representative for modeling for this permit in the locale of Gavilon.

3.3.5 Effects of Terrain on Modeled Impacts

Terrain data were extracted from United States Geological Survey (USGS) 7.5 minute data in National Elevation Dataset (NED) format in 10-meter spacing. DEQ confirmed accuracy of the data by recalculating receptor elevations from the current data sets downloaded in NED format. The data as modeled are adequate for this analysis.

The terrain preprocessor AERMAP Version 11103 was used to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

DEQ reviewed the area surrounding the facility by using the web-based mapping program Google Earth, which uses the WGS84 datum. DEQ also overlaid modeling files with a digital photograph background images acquired from the 2013 ARCGIS National Agriculture Imagery Program (NAIP) database. The immediate area is effectively flat with regard to dispersion modeling affects. Elevations in the modeling domain matched those indicated by the background images.

3.3.6 Facility Layout

DEQ compared the facility layout used in the model to that indicated in aerial photographs on Google Earth.

The modeled layout was consistent with aerial photographs in Google Earth as well as from those in the ARCGIS 2013 NAIP database.

3.3.7 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes are usually accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of existing and proposed buildings were needed as input to the Building Profile Input Program for the Plume Rise Model Enhancements (BPIP-PRIME) downwash algorithm because there are existing structures affecting the emissions plumes at the facility.

3.3.8 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." Public access to the Gavilon facility is limited by existing fence-lines and signage. In addition, facility personnel patrol the property. This approach is adequate to preclude public access to areas excluded from the air impact assessment.

3.3.9 Receptor Network

Table 7 describes the receptor grid used in the submitted analyses. The receptor grid met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[1]. DEQ determined this grid assured that maximum impacts were reasonably resolved by the model considering: 1) types of sources modeled; 2) modeled impacts and the modeled concentration gradient; 3) conservatism of the methods and data used as inputs to the analyses; 4) potential for continual exposures or exposure to sensitive receptors.

3.3.10 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

$H = S + 1.5L$, where:

H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.

S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.

L = lesser dimension, height or projected width, of the nearby structure.

Buildings exist in the vicinity of all point sources modeled. Therefore, consideration of downwash caused by nearby buildings was required.

4.0 Impact Modeling Results

This section presents results of the air impact analyses used to demonstrated compliance with applicable NAAQS and TAP increments.

4.1 Results for NAAQS Impact Level Analyses

Because estimated emission increases for the project were above Level I Modeling Applicability Thresholds, air quality dispersion modeling was necessary for the criteria pollutants PM_{10}, $PM_{2.5}$, and NO_2. The ambient air impact analyses submitted with the PTC application first assessed the emissions from the project to determine if cumulative NAAQS modeling analyses should be done for each pollutant. These results are listed in Table 9 and show that cumulative NAAQS modeling is required for PM_{10}, $PM_{2.5}$, and NO_2 for all relevant time periods. As noted in Section 3, DEQ revised the submitted "modeled" annual emission rates to reflect the annual capacities as listed in the application for sources M1-M5 and SH1-SH7. Therefore, the annual $PM_{2.5}$ impacts listed in Table 10 are larger than those as shown in the application, but still comply with all NAAQS. The cumulative NAAQS modeling demonstrated to DEQ's satisfaction that emissions from Gavilon will not cause or significantly contribute to a NAAQS violation. These results are listed in Table 10.

Table 9. RESULTS FOR SIGNIFICANT IMPACT ANALYSES

Pollutant	Averaging Period	Maximum Modeled Conc ($\mu g/m^3$)[a]	Significant Impact Level (SIL)	% of SIL	NAAQS Modeling Required?
PM_{10}	24-hour	20.2[b]	5	404%	Yes
$PM_{2.5}$	24-hour	5[c]	1.2	418%	Yes
	Annual	1.3[d]	0.3	440%	Yes
NO_2	1-hour	138[e,f]	7.5	1840%	Yes
	Annual	14.5[d,f]	1	1448%	Yes

a. Micrograms per cubic meter.
b. Highest modeled 24-hour impact.
c. The 5-year mean of the 1st highest modeled 24-hour impacts.
d. Highest annual impact.
e. The 5-year mean of 1st highest modeled 1-hour impacts for each year.
f. ARM2 method utilized for NO_2/NO_x ratio for NO_x chemistry modeling.

Table 10. RESULTS FOR CUMULATIVE NAAQS IMPACT ANALYSES

Pollutant	Averaging Period	Design Modeled Concentration ($\mu g/m^3$)[a]	Ambient Background ($\mu g/m^3$)[a]	Total Impact ($\mu g/m^3$)[a]	NAAQS ($\mu g/m^3$)[a]
NO_2	1-hour	127.6[b]	31.96	159.60	188
	Annual	12.0[c]	5.83	17.83	100
$PM_{2.5}$	24-hour	15.1[d]	13	28.1	35
	Annual	4.3[c]	4.3	8.6	12
PM_{10}	24-hour	97.2[e]	47.0	144.2	150

a. Micrograms per cubic meter.
b. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled.
c. 5-year mean of annual averages at the modeled receptor.
d. 5-year mean of the 8th highest modeled 24-hour concentrations
e. High sixth-high concentration over a period of five years

4.2 Results for TAPs Impact Analyses

Dispersion modeling is required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 and 586 for those TAPs with project-specific emission increases exceeding emissions screening levels (ELs). Because there are TAPs emissions that exceeds the ELs, modeling analyses were needed to demonstrate compliance with those AACs and AAACs. The results are listed in Table 11 and show that compliance is demonstrated for all AACs and AAACs.

Table 11. RESULTS FOR TAP IMPACT ANALYSES

TAP	Averaging Period	Maximum Modeled Impact (μ/m³)[a]	AAC or AACC (μg/m³)[a]
Arsenic	Annual	3.00E-05	2.30E-04
Cadmium	Annual	1.50E-04	5.60E-04
Formaldehyde	Annual	1.05E-02	7.70E-02
Nickel	Annual	3.00E-04	4.20E-03

a. Micrograms per cubic meter

5.0 Conclusions

The ambient air impact analyses and other air quality analyses submitted with the PTC application demonstrated to DEQ's satisfaction that emissions from the Gavilon project will not cause or significantly contribute to a violation of any ambient air quality standard.

References:

1. *State of Idaho Guideline for Performing Air Quality Impact Analyses.* Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

2. Air Quality Environmental Science and Technology Consortium (NW AIRQUEST). *Lookup 2009-2011 Design Values of Criteria Pollutants*. Available at: http://lar.wsu.edu/nw-airquest/lookup.html.

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on May 7, 2018:

Facility Comment (General #2): The permittee is referred to as Gavilon Grain, LLC dba Peavey Company. Please remove the reference to Peavey Company in the permitting documents. The facility is owned and operated by Gavilon Grain and is no longer doing business as Peavey Company.

DEQ Response: Permitting documents have been updated to reflect the requested change.

Facility Comment (PTC #1): The corn flaking units listed in Table 1.1 are not consistent with the way the units are listed in Table 2.1. Specifically, Table 1.1 lists individual pieces of equipment, whereas Table 2.1 groups units into Grain Handling, Corn Flaking Mill Rollers and Cooler Dyer, and Flake Storage Pile Handling and Grain Shipping. Gavilon requests that the method used in Table 2.1 also be used in Table 1.1, as this will reduce potential for confusion regarding which processes are controlled by certain types of control devices.

DEQ Response: The draft permit has been updated. Key information has been combined into a single Table 1.1 (from both Tables 1.1 and 2.1), using the requested format.

Facility Comments (PTC #2, #4, #7, #10, and #11):

The Flaker Cooler Cyclone is listed in this table as a piece of control equipment. Gavilon believes that this cyclone is a piece of inherent process equipment, and therefore should not be treated as required control equipment in the permit. The primary purpose of the Flaker Cooler Cyclone is to aid in the flake cooling process, as well as to recover valuable flake product that will then be reintroduced to the system. As such, the primary purpose of the cyclone is not to control air pollution and Gavilon would install the cyclone even if no air quality regulations were in place. Therefore, the cyclone meets the criteria to be classified as process equipment as laid out in an EPA memo.[7] As process equipment, the cyclone should not be listed in the permit as control equipment, and the permit should not contain monitoring or recordkeeping requirements related to cyclone operation and maintenance. There is already an incentive to properly operate and maintain the Flaker Cooler Cyclone without permit conditions related to operation and maintenance because the cyclone is operated as process equipment.

Gavilon requested removal of the Flaker Cooler Cyclone stack testing requirement. Gavilon believed removal was justified because the Flaker Cooler Cyclone is a piece of inherent process equipment, and because the emission factor utilized to estimate emissions was based upon Method 5 testing of a flaker cooler cyclone stack of a similar facility. Gavilon scaled the tested emission factor to account for size differences and included a safety factor in the emission calculations. Gavilon believes that the developed emission factor is more representative than AP-42 emission factors for a steam flaking process, and that performance testing is therefore unnecessary.

In the event that performance testing is ultimately required, Gavilon requested removal of the requirement to record mineral oil application rate and corn moisture content during performance testing. Corn utilized in the flaking system will likely be stored for a period of time before being sent to the flaking system (i.e., grain will not be processed to flakes on the same day it is received). Therefore, mineral oil and corn moisture contents of grain received the day of testing may or may not be consistent with the mineral oil or moisture content of corn processed in the steam flaker during a performance test. Gavilon also requests that IDEQ allow Gavilon to record throughput rate in tons per hour, as flaking product is generally measured in tons instead of bushels.

DEQ Response:

The draft permit has been updated. Because information was provided supporting that this emissions unit is inherent process equipment, the Cyclone was removed from the list of control equipment list (Table 1.1), and monitoring requirements have not been required for this equipment.

Although conservative assumptions have been included in emission estimates for this source, the initial PM_{10} performance test has been retained due to remaining concerns regarding emission factor uncertainty, including potential differences between the proposed process and the process from which the emission factor was derived.

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[7] Letter from Harnett, EPA Integration Division to Herbert, National Ready Mixed Concrete Association, July 2002 and letter from Solomon, EPA Integrated Implementation Group, to Mohin, Intel Government Affairs, November 1995.

Potential emissions from this emissions unit were estimated at less than the minimum allowable PM limit for process equipment as provided in IDAPA 58.01.01.700.02, and at less than the significant emission rate (as defined in IDAPA 58.01.01.006), relying upon an emission factor significantly lower than what is provided in AP-42.[1] The representativeness of estimated emissions will be verified if compliance with the cyclone emission limit in Permit Condition 2.3 is demonstrated during an initial performance test at indicated throughputs, and ongoing testing and monitoring would not be considered necessary.

Monitoring and recordkeeping requirements during performance testing were retained to verify assumptions relied upon in estimating emissions. Permit Condition 2.31 allows for DEQ approval of alternate monitoring approaches. With regard to approving and resolving specific testing protocols, monitoring methodologies, and deviations, DEQ encourages the applicant to submit a performance test protocol for approval at least 30 days prior to testing in accordance with General Provision 3.8.

Facility Comment (PTC #3, 4):

Gavilon requested changes to the process description (Section 2.1) to more accurately reflect the processes utilized at the Burley location. Due to differences in utilized controls, Gavilon believes that the Flake Storage Pile Handling process should be separated from the Grain Shipping Process.

(see attached letter highlighting the specific changes requested to permit language)

DEQ Response: The draft permit process descriptions have been updated.

Facility Comment (PTC #5):

Gavilon requested that the PM_{10} emission limitations for Grain Receiving (Table 2.3) be revised to 0.28 lb/hr and 0.18 tons/yr. These updated emission rates were provided to IDEQ in the February 2018 emission inventory submittal. While revising dispersion modeling at the request of IDEQ, Gavilon learned of differences between Grain Receiving scenarios assumed in the 2010 PTC and Grain Receiving Scenarios that the facility is capable of using. There have been no physical modifications to Grain Receiving equipment at the facility since issuance of the 2010 PTC, but the corrected Grain Receiving capabilities led to a decrease in potential lb/hr PM_{10} emissions and a slight increase in potential tons/yr PM_{10} emissions. Gavilon conducted air dispersion modeling using the updated emission rates.

DEQ Response:

The draft permit has been updated, consistent with the updated emission estimates submitted in the application.

Facility Comment (PTC #6):

Gavilon requested that the 893 bushels per hour limit be changed to 25 tons per hour, as was noted in the application. The Corn Flaking Throughput limit is listed in units of bushels per hour. For the steam flaking process, material is tracked in tons instead of bushels.

DEQ Response:

The draft permit has been updated, consistent with the emission estimates submitted in the application and to facilitate compliance using the preferred method of measurement. Emission estimates were calculated based on throughputs assessed on either a weight (T/hr) or volumetric (bushels/hr) basis.

Facility Comment (PTC #8, #9):

Gavilon requested that Subpart Dc requirements be changed to allow the facility to maintain records of the total amount of natural gas combusted in the boiler each month, as allowed in 40 CFR 60.48c(g)(2). The boiler will have a dedicated natural gas line, and Gavilon intends to keep records of natural gas combustion in the boiler in order to comply with NSPS requirements.

Since the boiler is limited to combusting only natural gas, Gavilon requested clarification that reporting is not required by the NSPS beyond notifications regarding construction and initial startup dates.

DEQ Response:

Permit Condition 2.27 has been updated to specify the preferred compliance alternative, and to clarify that only notification (not reporting) is required for this source.

Facility Comment (Modeling Memo #7):

Gavilon requested that the draft PTC be updated to allow the hammermills to operate at 13 hours per day instead of 12 hours per day.

In the previous permitting action, the modeling submitted and the revised PTC restricted hammermills, truck drop, and product loadout to 12 hours per day of operation. The emission inventories submitted for the proposed project document that facility-wide potential emissions would be unaffected if permitted hours of operation of each hammermill were increased from 12 hours to 13 hours each day. Short-term potential emissions (lb/hr) are limited based upon the hourly throughput capacities of each emission unit, while annual potential emissions are based upon annual throughput limits (T/yr). Therefore, hours of operation of the hammermills are not used when calculating potential emissions estimates (i.e., potential emissions are based upon throughput limits).

DEQ Response:

Permit Condition 2.11 has been updated to permit increased hammermill operation for an additional hour per day, consistent with assumptions used in estimating and modeling facility-wide emissions to demonstrate compliance with NAAQS.

Additional Facility Comments on the Statement of Basis and Modeling Memo:

Beyond the comments addressed above, the Statement of Basis and Modeling Memo have been updated as requested, consistent with the information provided in these responses and in the application.

(see attached letter highlighting the specific changes requested to language in the Statement of Basis and Modeling Memo)

NAQS
ENVIRONMENTAL EXPERTS

301 South 9th Street
Suite 200
Lincoln, Nebraska 68508

May 7, 2018

VIA EMAIL

Mr. Morrie Lewis
Permit Writer
Air Quality Division
Idaho Department of Environmental Quality
1410 North Hilton
Boise, ID 83706

RE: Draft Permit to Construct Comments
Gavilon Grain, LLC - Burley
Facility ID #031-00038
Draft Permit #P-2009.0091 Project 61957

Dear Mr. Lewis,

On behalf of Gavilon Grain, LLC (Gavilon), NAQS *Environmental Experts* hereby submits the attached comments on the draft Permit to Construct (PTC) referenced above for Gavilon Grain, LLC – Burley. As requested, these comments are being submitted to your attention within 10 days of receiving a copy of the draft permit for this project.

Gavilon and I would like to thank you for the opportunity to review the draft PTC prior to public notice. Please feel free to contact me at (402) 489-1111 or bob@naqs.com if you have any questions or if you would like to discuss any of the comments.

Sincerely,

Robert Sheeder
Senior Consultant
NAQS *Environmental Experts*

Cc: Brian Wanzenried – Director of Environmental, Gavilon Grain

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GAVILON

Gavilon Grain, LLC – Burley
Comments of Draft PTC Documents
Facility ID: 031-00038
Project ID: 61970

General Comments

1. Gavilon would like to thank IDEQ for highlighting the substantial changes to the PTC throughout the draft permitting documents. The highlights were very helpful and allowed Gavilon to do a thorough yet efficient review of the permit document.
2. Throughout the Permit to Construct (PTC) and the Statement of Basis (SOB), the permittee is referred to as Gavilon Grain, LLC dba Peavey Company. Please remove the reference to Peavey Company in the permitting documents. The facility is owned and operated by Gavilon Grain and is no longer doing business as Peavey Company.

Comments on PTC

1. Page 4, Table 1.1: The corn flaking units listed are not consistent with the way the units are listed in Table 2.1 on Page 5. Specifically, Table 1.1 lists individual pieces of equipment, whereas Table 2.1 groups units into Grain Handling, Corn Flaking Mill Rollers and Cooler Dyer, and Flake Storage Pile Handling and Grain Shipping. Gavilon requests that the method used in Table 2.1 also be used in Table 1.1, as this will reduce potential for confusion regarding which processes are controlled by certain types of control devices.
2. Page 4, Table 1.1: The Flaker Cooler Cyclone is listed in this table as a piece of control equipment. Gavilon believes that this cyclone is a piece of inherent process equipment, and therefore should not be treated as required control equipment in the permit. The primary purpose of the Flaker Cooler Cyclone is to aid in the flake cooling process, as well as to recover valuable flake product that will then be reintroduced to the system. As such, the primary purpose of the cyclone is not to control air pollution and Gavilon would install the cyclone even if no air quality regulations were in place. Therefore, the cyclone meets the criteria to be classified as process equipment, as laid out in a July 10, 2002 USEPA memo to Mr. Edward R. Herbert III, the Director of Governmental Affairs for the National Ready Mixed Concrete Association (see attached). As process equipment, the cyclone should not be listed in the permit as control equipment, and the permit should not contain monitoring or recordkeeping requirements related to cyclone operation and maintenance. There is already an incentive to properly operate and maintain the Flaker Cooler Cyclone without permit conditions related to operation and maintenance because the cyclone is operated as process equipment.
3. Page 5, Section 2.1 – Process Description: Gavilon requests that the following changes be made to the process description in order to more accurately reflect the processes utilized at the Burley location (changes highlighted).

   The Gavilon Grain, LLC ~~dba Peavey Company~~ in Burley, Idaho manufactures animal feed. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. Processes include use of receiving pits, grain distribution legs, hammermills, conveyors, screw augers, storage bins, and storage piles.

   *****

   The corn flaking process involves cleaning and scalping corn in the Rotary Grain Cleaner, steaming corn in the steam chamber, rolling corn into flakes in the flaking mill rollers, and cooling and drying flakes prior to shipment. A boiler generates steam for the steam chamber.

GAVILON

4. Page 4, Table 2.1: Due to differences in utilized controls, Gavilon believes that the Flake Storage Pile Handling process should be separated from the Grain Shipping Process. Also, Gavilon believes that the Flaker Cooler Cyclone qualifies as process equipment under USEPA guidance and should not be listed in the table as a control device. Gavilon requests the following changes to Table 2.1 for added clarity regarding Emission Processes and Control Devices (changes highlighted)

Emission Units/Processes	Control Devices
Grain Processing 1. Grain Receiving 2. Grain Handling 3. Grain Storage 4. Grain Cleaning 5. Grain Milling (Hammermill Nos. 1 to 5) 6. Grain Shipping 7. Corn Flaking Mill Rollers and Cooler Dryer 8. Flake Storage Pile Handling and Flake Shipping	Grain Receiving Choke feed, Shroud Grain Handling Enclosure, Mineral Oil Application Grain Storage Mineral Oil Application Grain Cleaning Enclosed and Mineral Oil Grain Milling Mineral Oil Application Baghouse Nos 1, 2, & 3 for Hammermill Nos 1, 2, & 3 Cyclone Nos 1 & 2 for Hammermill Nos 4 & 5 Grain Shipping (excluding transloaded material) Mineral Oil Application Corn Flaking Mill Rollers and Cooler Dryer None Flake Storage Pile Handling and Flake Shipping Partial Enclosure

5. Page 6, Table 2.3 Grain Processing Emission Limits – Gavilon requests that the PM10 emission limitations for Grain Receiving be revised to 0.28 lb/hr and 0.18 tons/yr. These updated emission rates were provided to IDEQ in the February 2018 emission inventory submittal. While revising dispersion modeling at the request of IDEQ, Gavilon learned of differences between Grain Receiving scenarios assumed in the 2010 PTC and Grain Receiving Scenarios that the facility is capable of using. There have been no physical modifications to Grain Receiving equipment at the facility since issuance of the 2010 PTC, but the corrected Grain Receiving capabilities led to a decrease in potential lb/hr PM10 emissions and a slight increase in potential tons/yr PM10 emissions. Gavilon conducted air dispersion modeling using the updated emission rates.

6. Page 7, Condition 2.11: The limit is listed in units of bushels per hour. For the steam flaking process, material is tracked in tons instead of bushels. Gavilon requests that the 893 bushels per hour limit be changed to 25 tons per hour, as was noted in the application.

7. Page 8, Conditions 2.16 and 2.17: The Flaker Cooler Cyclone is listed in these conditions as required control equipment with monitoring requirements. As explained in PTC Comment 2 above, Gavilon believes that the Flaker Cooler Cyclone qualifies as a piece of process equipment and should be removed from these conditions.

8. Page 11, Condition 2.28, NSPS Subpart Dc Requirements, Bullet 1: Gavilon requests that this bullet be changed to allow the facility to also maintain records of the total amount of natural gas combusted in the boiler each month, as allowed in 60.48c(g)(2). The boiler will have a dedicated natural gas line

and Gavilon intends to keep records of natural gas combustion in the boiler in order to comply with the NSPS requirements.

9. Page 11, Condition 2.28, NSPS Subpart Dc Requirements, Bullet 3: Gavilon requests that this bullet be removed in its entirety. Since the boiler is limited by the PTC to combusting only natural gas, Gavilon is not required by the NSPS to submit any reports other than notifications regarding construction and initial startup dates. This bullet can cause confusion and lead the reader to believe that Gavilon is required to submit semi-annual reports under the NSPS.
10. Page 12, Condition 2.30: Gavilon requests that IDEQ remove the Flaker Cooler Cyclone stack testing requirement in its entirety. As noted in PTC Comment 2, Gavilon believes that the Flaker Cooler Cyclone is a piece of inherent process equipment, not a control device. Furthermore, as was noted in the PTC and subsequent information submittals, the emission factor utilized to estimate emissions from the Flaker Cooler Cyclone stack is based upon USEPA Method 5 testing on a flaker cooler cyclone stack of a similar facility. Based on the information presented to IDEQ regarding the flaker cooler testing, Gavilon believes that the testing results are more representative than AP-42 emission factors for a steam flaking process. Gavilon also scaled the tested emission factor to account for size differences and added a safety factor when calculating emissions from the Flaker Cooler Cyclone. For these reasons, Gavilon believes that IDEQ should feel confident that the emission factor utilized is conservative and representative of the flake cooling process, and therefore performance testing should not be necessary.
11. Page 12, Condition 2.31: Gavilon believes that performance testing of the Flaker Cooler Cyclone stack is not necessary, as discussed in the PTC application and subsequent information submittals. However, in the event that performance testing is ultimately required, Gavilon requests that IDEQ strike the requirements to record mineral oil application rate and corn moisture content during performance testing. Corn utilized in the flaking system will likely be stored for a period of time before being sent to the flaking system (i.e., grain will not be processed to flakes on the same day it is received). Therefore, mineral oil and corn moisture contents of grain received the day of testing may or may not be consistent with the mineral oil or moisture content of corn processed in the steam flaker during a performance test.

    Gavilon also requests that IDEQ allow Gavilon to record throughput rate in tons per hour, as flaking product is generally measured in tons instead of bushels.

<u>Comments on SOB</u>

1. Page 4, Facility Description: Gavilon requests that the process description in the SOB be changed to the language requested in PTC Comment 5.
2. Page 5, Permitting History: Gavilon requests that IDEQ correct the description of the July 12, 2012 PTC. This PTC was issued in order to remove the requirement to apply mineral oil to high moisture grain.
3. Pages 6 and 7, Table 1: Gavilon requests that this table be changed to match the requested changes in PTC Comments 1 and 2.
4. Page 7, Potential to Emit, Paragraph 2: Gavilon would like to clarify that the emission factor for the Flaker Cooler Cyclone was not based upon manufacturer design specification. Instead, the emission factor was based on stack testing conducted on a cooler cyclone at a similarly designed corn steam flaking plant.
5. Pages 9 and 10, Pre- and Post-Project Emissions Tables, Transloading Activities: Gavilon has reviewed the PTC exemption documentation submitted to IDEQ regarding transloading feed ingredients at the Burley facility. The PM10 T/yr emissions reported in the Pre- and Post-Project tables match the emissions totals provided by Gavilon. However, there are discrepancies in the lb/hr emission rates. Gavilon submitted the following PM10 emission rates as part of the PTC exemption documentation:

Transload Receiving: 0.30 lb/hr
Transload Internal Handling: 8.16 lb/hr
Transload Truck Loadout: 0.19 lb/hr
Transload Pile Activity: 0.13 lb/hr
Transload Pile Wind Erosion: 0.09 lb/hr
Transload Shipping from Storage Piles: 0.26 lb/hr

6. Page 10, Post-Project Emissions Table, Grain Receiving: As documented in the February 2018 emissions inventory submittal and discussed in PTC Comment 5, Gavilon requests that the Grain Receiving PM10 emission rates be changed to 0.28 lb/hr and 0.18 T/yr.

7. Page 42, Process Description, Paragraph 1: Gavilon requests that the following changes be made to the process description in order to more accurately reflect the processes utilized at the Burley location (changes highlighted).

   The Gavilon Grain, LLC ~~dba Peavey Company~~ in Burley, Idaho manufactures animal feed. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. The facility consists of the following: six receiving pits, four distribution legs, five hammermills, 16 conveyors, nine screw augers, 14 storage silos, and two temporary storage piles.

8. Page 43, Table 2.2: As discussed in PTC Comment 5 and SOB comment 6, Gavilon requests that Grain Receiving PM10 limits be revised to 0.28 lb/hr and 0.18 T/yr.

Modeling Memo Comments

1. Page 3, Summary, Paragraph 2 and 3: Gavilon requests that the following changes be made to the process description in order to more accurately reflect the processes utilized at the Burley location (changes highlighted).

   Gavilon operates a grain elevator and animal feed manufacturing facility in Burley, Idaho. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. The processes include use of receiving pits, grain distribution legs, hammermills, conveyors, screw augers, storage bins, and storage piles. Grain is received mostly be railcar, although some arrives by truck. The grain is unloaded into below-grade pits and then treated with edible mineral oil to control dust during the handling process. The grain is transported by conveyors to various destinations within the facility. Grinding is done with hammermills, and grinding emissions are controlled by cyclones and baghouses. The processed grain is stored in silos until shipment.

   The PTC application was submitted for construction of a new corn steam flaking mill. Gavilon plans on installing new (enclosed) draw spouts to existing storage bins. These spouts convey corn to the new Flaking System Transfer Let. This leg is an enclosed bucket elevator which moves the corn to a new conveyor and a new Flaker System Storage Bin. The corn ~~grain~~ is then moved to another area where the corn is cleaned, refined, and eventually dropped into the flaking steam chamber, where a new boiler is used to treat the grain with the proper amount of moisture before being fed into the flaking mill rollers. Here the corn is rolled into flakes and dried. The final product is then stored before sale.

2. Page 4, Table 1, General Emission Rates Explanation: This table states that hammermills, truck drops, and product loadouts were modeled at 13 hours per day of operation. The previous PTC, the modeling submitted with the flaking system PTC application, and the revised draft PTC all restricted hammermills, truck drop, and product loadout to 12 hours per day of operation. Having said that, if IDEQ has modeled these processes at 13 hours per day and is satisfied that the facility demonstrates compliance with the applicable NAAQS, Gavilon requests that the draft PTC be updated to allow each of the hammermills to operate at 13 hours per day instead of 12 hours per day.

3. Page 5, Project Description, Paragraph 1: Gavilon requests that the following changes be made to the process description in order to more accurately reflect the processes utilized at the Burley location (changes highlighted).

   Gavilon operates a grain elevator and animal feed manufacturing facility in Burley, Idaho. The facility receives whole corn and grinds it into animal feed. The facility also transloads, without further processing at the facility, dried distiller grains (a byproduct of ethanol fuel production), canola pellets, and wheat. This PTC is being submitted for construction of a new corn steam flaking mill. More detailed information can be found in Section 1 of this document, as well as the Statement of Basis for this project.

4. Page 11, Table 5, Source IDs M4 and M5: The description identifies these hammermills as controlled by baghouses. This needs to be revised to show that these two hammermills are controlled by cyclones. The modeled emission rates assumed cyclone control.
5. Page 12, Table 5, Source ID GR2: The PM10 emission rates should be listed as 0.438 lb/hr of PM10 and 0.0074 lb/hr of PM2.5, not 0 lb/hr.
6. Page 14, Table 7, Source IDs M4 and M5: The description identifies these hammermills as controlled by baghouse. This needs to be revised to show that these two hammermills are controlled by cyclones. The modeled emission rates assumed cyclone control.
7. Page 17, Modeling Protocol and Methodology: This table states that hammermills, truck drops, and product loadouts are limited to 13 hours per day. The previous PTC, the modeling submitted with the flaking system PTC application, and the revised draft PTC all restricted hammermills, truck drop, and product loadout to 12 hours per day of operation. Having said that, if IDEQ has modeled these processes at 13 hours per day of operation and is satisfied that the facility demonstrates compliance with the applicable NAAQS, Gavilon requests that the draft PTC be updated to allow the hammermills to operate at 13 hours per day instead of 12 hours per day.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

July 10, 2002

Mr. Edward R. Herbert III
Director of Environmental Affairs
National Ready Mixed Concrete Association
900 Spring Street
Silver Spring, MD 20910

Dear Mr. Herbert:

Your April 30, 2002, letter requests a review from the Environmental Protection Agency (EPA) regarding the inclusion of control devices on pneumatically loaded cement silos in the "potential to emit" calculations for ready mixed concrete plants. We agree with your assessment that, for potential to emit calculations, the control devices on the silos generally should be considered as an inherent part of the process for loading ready mixed cement silos.

Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment

For purposes of calculating a source's potential to emit, it is necessary to consider the effect of air pollution control equipment. Current EPA regulations and policy allow air pollution control equipment to be taken into account if enforceable requirements are in place requiring the use of such air pollution control equipment. There are, however, situations for which case-by-case assessments are needed regarding whether a given device or strategy should be considered as air pollution control equipment, or as an inherent part of the process. The EPA believes that the following list of questions should be considered in assessing whether certain devices or practices should be treated as pollution controls or as inherent to the process:

1. Is the primary purpose of the equipment to control air pollution?

2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

3. Would the equipment be installed if no air quality regulations are in place?

If the answers to these questions suggest that equipment should be considered as an inherent part of the process, then the effect of the equipment or practices can be taken into account in calculating potential emissions regardless of whether enforceable imitations are in effect.

Analysis of the criteria for control devices on pneumatically loaded cement silos

The equipment used for pneumatic loading is commonly referred to as bag houses or dust collectors. Based on the information supplied to date by you, the EPA believes that, overall, the above criteria are satisfied as follows:

Criteria 1. The primary purpose of the control devices on pneumatically loaded cement silos is not to control air pollution but to provide a restricted air flow from the silo so that the silo will fill properly without excessive loss of product.

Criteria 2. The cement collected by the filters falls into the silo and is recovered for use as product. The cost savings from this product recovery varies depending on such factors as silo capacity, amount of product in the silo, and the efficiency and cost of the control device.

Criteria 3. The information you have provided suggests strongly that air quality regulations are not the driving factor for installation of the control equipment. The control devices would be installed regardless of air quality requirements.

Cautions

The views expressed above regarding the use of the control devices for loading cement silos are specific for ready mixed concrete facilities using pneumatic loading. While we believe the views in this letter are applicable for the majority of ready mixed concrete facilities with pneumatic loading, there may be circumstances that would need to be considered on a case-by-case basis. For example, there may be situations where air pollution control regulations or a company's desire to limit its potential to emit for regulatory purposes result in the company's installation or use of bag houses with a greater collection efficiency than would be the case if product recovery or other process considerations were the only factors at work. Should such circumstances arise, source owners and operators are encouraged to work with their permitting authorities if they have questions.

This letter is not intended to set a precedent for control equipment for other source types, which must be reviewed separately. This letter also does not assess the control efficiency or emissions from the baghouses. Also, this determination does not exempt these sources from otherwise applicable permitting or other regulatory requirements. These requirements are determined by the appropriate permitting authority.

If you have any further questions regarding this matter, please call me at (919) 541-4718, or Mike Sewell at (919) 541- 0873.

Sincerely,

original signed by Robert Kellam for

William T. Harnett
Director, Information Transfer and Program Integration Division

cc: Regional Air Division Directors
Mario Jorquera, OECA
Greg Foote, OGC
Karen Blanchard, IIG
Steve Hitte, OPG
Kirt Cox, OPG
Mike Sewell, IIG

APPENDIX D – PROCESSING FEE

PTC Processing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Gavilon Grain, LLC - Burley**
Address:	**1111 Bedke Blvd**
City:	**Burley**
State:	**ID**
Zip Code:	**83318**
Facility Contact:	**Brian Wanzenreid**
Title:	**Director of Environmental**
AIRS No.:	**031-00038**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	7.0	0	7.0
SO_2	0.1	0	0.1
CO	2.7	0	2.7
PM10	3.0	0	3.0
VOC	0.6	0	0.6
TAPS/HAPS	0.8	0	0.8
Total:	0.0	0	**14.3**
Fee Due	**$ 5,000.00**		

Comments: