San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

JAN 24 2014

Mr. Jeff Schultz
ConAgra Foods
544 S Yosemite Ave
Oakdale, CA 95361

Re: Proposed ATC / Certificate of Conformity (Significant Mod)
District Facility # N-1976
Project # N-1132542

Dear Mr. Schultz:

Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. This project is to install a new 176.5 MMBtu/hr natural gas-fired boiler which will be served by a selective catalytic reduction system.

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the Authority to Construct with a Certificate of Conformity. Please submit your comments within the 30-day public comment period, as specified in the enclosed public notice. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Rupi Gill, Permit Services Manager, at (209) 557-6400.

Thank you for your cooperation in this matter.

Sincerely,

David Warner
Director of Permit Services

Enclosures

cc: Mike Tollstrup, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

San Joaquin Valley Air Pollution Control District
Authority to Construct
Application Review

Facility Name:	ConAgra Foods	Date:	January 21, 2014
Mailing Address:	544 S Yosemite Ave Oakdale, CA 95361	Engineer: Lead Engineer:	Jagmeet Kahlon Nick Peirce
Contact Person:	Jeff Schultz		
Telephone:	(209) 840-1146		
Application #(s):	N-1976-27-0		
Project #:	N-1132542		
Deemed Complete:	September 24, 2013		

I. PROPOSAL

ConAgra Foods is requesting an Authority to Construct (ATC) permit to install a new 176.5 MMBtu/hr natural gas fired boiler. This boiler will be equipped with a selective catalytic reduction (SCR) system to reduce NO_x emissions. This boiler will replace the existing boilers under permits N-1976-3 (111 MMBtu/hr boiler #3) and '-5 (63 MMBtu/hr boiler #1).

ConAgra Foods is a Major Source for NO_x and greenhouse gas (GHG) emissions. The facility is operating under Title V permit. This project triggers a public notice since the project is a Federal Major Modification per District Rule 2201, and it is a "significant modification" under District Rule 2520. Therefore, this project will be published in the local newspaper, Modesto Bee, for public review and comment. The public comment period will last 30 days from the date of publication. The facility has also proposed to obtain ATC with Certificate of Conformity (COC), which is EPA's 45-day review before the issuance of final ATC. Both COC and public notice will run concurrently.

II. APPLICABLE RULES

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (11/26/12)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2550	Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emission Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101	Visible Emissions (02/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)

Rule 4304	Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters (10/19/95)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (3/17/05)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters greater than 5.0 MMBtu/hr (10/16/08)
Rule 4351	Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4801	Sulfur Compounds (12/17/92)

California Health & Safety Code 41700 (Public Nuisance)
California Health & Safety Code 42301.6 (School Notice)
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. PROJECT LOCATION

This facility is located at 544 S. Yosemite Ave, Oakdale, California.

This unit will not be located within 1,000 feet of any K-12 school. Therefore, the project will not trigger the school and public noticing requirements of Section 42301.6 of the California Health & Safety Code 42301.6.

IV. PROCESS DESCRIPTION

The boiler will provide steam to various food manufacturing operations.

V. EQUIPMENT LISTING

176.5 MMBTU/HR CLEAVER BROOKS MODEL NB-500D-100 NATURAL GAS-FIRED WITH A CLEAVER BROOKS MODEL NATCOM LOW NOX BURNER AND A C&C PANASIA (OR EQUIVALENT MANUFACTURER) SELECTIVE CATALYTIC REDUCTION SYSTEM

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

Low-NO_X burners reduce formation of NO_X by producing lower flame temperatures (and longer flames) than conventional burners. Conventional burners thoroughly mix all the fuel and air in a single stage just prior to combustion, whereas low-NO_X burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NO_X. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

An SCR system operates as an external control device where flue gases and a reagent, in this case ammonia, are passed through an appropriate catalyst. Ammonia, will be injected upstream of the catalyst where it reacts and reduces NO_x, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NO_x emissions by up to 90%.

VII. CALCULATIONS

A. Assumptions

- Assumptions will be stated as they are made during the evaluation.

B. Emission Factors (EF)

1. Pre-Project Emission Factors (EF1)

The proposed boiler is a new emission unit. Therefore, EF1 does not exist at this time.

2. Post-Project Emission Factors (EF2)

Pollutant	EF2		Source
	lb/MMBtu	ppmvd @ 3% O_2	
$NO_{x\ Startup/shutdown}$	0.097	80	Applicant's proposal
$NO_{x\ Steady\text{-}state}$	0.0062	5.0	
SO_x	0.00285	--	District Policy APR-1720
PM_{10}	0.005	--	Applicant's proposal
$CO_{Startup/shutdown}$	0.074	100	
$CO_{Steady\text{-}state}$	0.037	50	
VOC	0.004	--	
NH_3	0.0042	10	Typical ammonia slip
CO2e	116.6	--	CARB' GHG factor sheet (3/10)

C. Potential to Emit

1. Pre-Project Potential to Emit (PE1)

PE1 = 0

2. Post-Project Potential to Emit (PE2)

NO_x, CO:
Startup/shutdown:
Per applicant, the total startup and shutdown is estimated to be 4 hr/day and 80 hr/yr. Thus,

PE2 (lb/day) = $EF2_{\text{Startup and shutdown}}$ lb/MMBtu × 176.5 MMBtu/hr × 4 hr/day
PE2 (lb/yr) = $EF2_{\text{Startup and shutdown}}$ lb/MMBtu × 176.5 MMBtu/hr × 80 hr/yr

Steady state:
PE2 (lb/day) = $EF2_{\text{Steady-state}}$ lb/MMBtu × 176.5 MMBtu/hr × (24 – 4) hr/day
PE2 (lb/yr) = $EF2_{\text{Steady-state}}$ lb/MMBtu × 176.5 MMBtu/hr × (8,760 – 80) hr/yr

SO_x, PM_{10}, CO, VOC:
PE2 (lb/day) = EF2 lb/MMBtu × 176.5 MMBtu/hr × 24 hr/day
PE2 (lb/yr) = EF2 lb/MMBtu × 176.5 MMBtu/hr × 8,760 hr/yr

CO2e:
PE2 (tons/yr) = EF2 lb/MMBtu × 176.5 MMBtu/yr × 8,760 hr/yr × ton/2,000 lb

Pollutant	EF2 (lb/MMBtu)	PE2 (lb/day)	PE2 (lb/yr)
$NO_{x\ \text{Startup and shutdown}}$	0.097	68.5	1,370
$NO_{x\ \text{Steady-state}}$	0.0062	21.9	9,499
NO_x (Total)	--	**90.4**	**10,869**
SO_x	0.00285	12.1	4,406
PM_{10}	0.005	21.2	7,731
$CO_{\text{Startup/shutdown}}$	0.074	52.2	1,045
$CO_{\text{Steady-state}}$	0.037	130.6	56,685
CO (Total)	--	**182.8**	**57,730**
VOC	0.004	16.9	6,185
NH_3	0.0042	17.8	6,494
CO2e	116.6	--	90,140 tons/yr

3. Quarterly Emissions Changes (QEC)

This calculation is required for application's emission profile, which is used for the District's internal tracking purposes. QECs are estimated as follows:

QEC = (PE2 – PE1)/4

Pollutant	QEC (lb/qtr)			
	Q1	Q2	Q3	Q4
NO_x	2,717	2,717	2,717	2,718
SO_x	1,101	1,101	1,102	1,102
PM_{10}	1,932	1,933	1,933	1,933
CO	14,432	14,432	14,433	14,433
VOC	1,546	1,546	1,546	1,547
NH_3	1,623	1,623	1,624	1,624

4. Adjusted Increase in Permitted Emissions (AIPE)

   AIPE is used to determine if BACT is required for emission units that are being modified. AIPE is calculated using the equations mentioned in Section 4.3 and 4.4 of Rule 2201.

   $$AIPE = PE2 - \left(\frac{EF2}{EF1}\right)(PE1)$$

   The proposed boiler is a new emissions unit. Therefore, AIPE calculations are not required.

D. Facility Emissions

1. Pre-Project Stationary Source Potential to Emit (SSPE1)

   Pursuant to Section 4.9 of District Rule 2201, SSPE1 is the Potential to Emit from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERCs) which have been banked since September 19, 1991 for Actual Emissions Reductions (AERs) that have occurred at the source, and which have not been used on-site.

   Except for permit unit N-1976-3, '-5 and '-6, the potential emissions for each permit unit are taken from the application review under project N-1132682. For permit units N-1976-3 and '-5, the potential emissions are estimated using the information in the PTOs. The potential emissions for permit unit N-1976-6 are taken from the application review under project N-1132615.

Permit #	Pollutants (lb/yr)				
	NO_x	SO_x	PM_{10}	CO	VOC
N-1976-3-7	10,696	2,771	4,862	35,977	1,361
N-1976-4-9	10,376	2,688	4,716	34,901	1,321
N-1976-5-7	6,071	1,573	4,194	20,420	552
N-1976-6-8	18,713	4,594	12,250	60,047	1,612

Continue...

Permit #	Pollutants (lb/yr)				
	NO_x	SO_x	PM_{10}	CO	VOC
N-1976-14-2	47	0	1	8	2
N-1976-17-2	357	0	11	77	29
N-1976-18-2	355	0	11	77	28
N-1976-21-2	0	0	767	0	0
N-1976-22-2	0	0	37	0	0
N-1976-24-0	4,876	2,147	5,726	27,874	4,143
N-1976-26-0	0	0	0	0	0
N-1976-28-0	0	0	0	0	0
ERCs	0	0	0	0	0
SSPE1	51,491	13,773	32,575	179,381	9,048

2. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The new boiler will replace the existing boilers under permits N-1976-3 (111 MMBtu/hr boiler #3) and '-5 (63 MMBtu/hr boiler #1). Therefore, the potential emissions for these units are not included in the following table.

Permit #	Pollutants (lb/yr)				
	NO_x	SO_x	PM_{10}	CO	VOC
N-1976-4-9	10,376	2,688	4,716	34,901	1,321
N-1976-6-8	18,713	4,594	12,250	60,047	1,612
N-1976-14-2	47	0	1	8	2
N-1976-17-2	357	0	11	77	29
N-1976-18-2	355	0	11	77	28
N-1976-21-2	0	0	767	0	0
N-1976-22-2	0	0	37	0	0
N-1976-24-0	4,876	2,147	5,726	27,874	4,143
N-1976-26-0	0	0	0	0	0
N-1976-27-0	**10,869**	**4,406**	**7,731**	**57,730**	**6,185**
N-1976-28-0	0	0	0	0	0
ERCs	0	0	0	0	0
SSPE2	45,593	13,835	31,250	180,714	13,320

3. Major Source Determination

Rule 2201 Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- Any ERCs associated with the stationary source
  Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)					
Category	NO_X	SO_X	PM_{10}	CO	VOC
SSPE1	51,491	13,773	32,575	179,381	9,048
SSPE2	45,593	13,835	31,250	180,714	13,320
Major Source Thresholds	20,000	140,000	140,000	200,000	20,000
Major Source?	Yes	No	No	No	No

From the above table, the facility is an existing Major Source for NO_x emissions.

Rule 2410 Major Source Determination

The facility or the equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore the following PSD Major Source thresholds are applicable.

PSD Major Source Determination (tons/year)							
Category	NO_2	VOC	SO_2	CO	PM	PM_{10}	CO2e
Estimated Facility PE before Project Increase	25.7	4.5	6.9	89.7	16.3	16.3	237,842[1]
PSD Major Source Thresholds	100	100	100	100	100	100	100,000
PSD Major Source ?	No	No	No	No	No	No	Yes

From the above table, the facility is an existing major source for PSD for GHG.

[1]CO2e emissions are taken from the application review under project N1132242.

4. Stationary Source Increase in Permitted Emissions (SSIPE)

The District practice is to define SSIPE as the difference of SSPE2 and SSPE1. Negative SSIPE values will be equated zero.

Pollutant	SSPE2 (lb/yr)	SSPE1 (lb/yr)	SSIPE (lb/yr)
NO_x	45,593	51,491	0
SO_x	13,835	13,773	62
PM_{10}	31,250	32,575	0
CO	180,714	179,381	1,333
VOC	13,320	9,048	4,272
NH_3	19039[2]	12,545	6,494

5. SB-288 Major Modification

The purpose of Major Modification calculations is to determine the following:

A. If Best Available Control Technology (BACT) is triggered for a new or modified emission unit that results in a Major Modification (District Rule 2201, §4.1.3); and

B. If a public notification is triggered (District Rule 2201, §5.4.1).

Per section VII.D.3 of this document, this facility is a Major Source for NO_x emissions. Thus, analysis is required to determine if this project triggers an SB-288 Major Modification.

To determine if the proposed project triggers an SB-288 major modification, net emission increase (NEI) is calculated by determining the sum of the difference of PE2 and historical emissions (HE) of all the units involved in the project. This NEI value is then compared with the SB 288 major modification threshold of 50,000 lb-NO_x/yr.

$$NEI = \sum(PE2 - HE)$$

HE is zero since the proposed boiler is a new emissions unit. Thus,

$$\begin{aligned} NEI &= \sum PE2 \\ &= PE2_{N\text{-}1976\text{-}27\text{-}0} \\ &= 10{,}869 \text{ lb-}NO_x\text{/yr} \end{aligned}$$

[2] SSEP2 = 3,962 lb-NH3/yr (N-1976-4-10) + 6,770 lb-NH3/yr (N-1976-6-9) + 1,813 lb-NH3/yr (N-1976-28-0) + 6,494 lb-NH3/yr (N-1976-27-0) = 19,039 lb-NH3/yr

The total NOx emissions from the unit involved in the project are less than the SB-288 major modification threshold. Therefore, this project is not an SB-288 major modification.

6. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Per section VII.D.3 of this document, this facility is a Major Source for NO_x emissions. Thus, analysis is required to determine if this project triggers a Federal Major Modification.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

NO_x emissions from the proposed new boiler are 10,782 lb/yr.

Emissions Increase = 10,869 lb/yr

The project's NO_x emission increase exceeds 0 lb/year threshold for Federal Major Modification. Therefore, this project is a Federal Major Modification.

VIII. COMPLIANCE

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

BACT requirements shall be triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis.

Unless exempted pursuant to Section 4.2, BACT shall be required for the following actions[3]:

- Any new emissions unit or relocation from one Stationary Source to another of an existing emissions unit with a Potential to Emit (PE2) exceeding 2.0 pounds in any one day;
- Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds in any one day;

[3]Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO

- Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined in this rule.

Per section VII.C.2 of this document, PE2 is greater than 2.0 lb/day for NO_x, SO_x, PM_{10}, CO, VOC and NH_3. Total CO emissions from this facility are less than 200,000 lb/yr. Thus, BACT is triggered for NOx, SOx, PM_{10}, VOC and NH_3 emissions. The District practice is not to consider BACT on emission control equipment; therefore, BACT for NH_3 emissions will not be evaluated.

The District conducts project-specific analyses for boilers similar to the one proposed in this project. BACT for units greater than 20 MMBtu/hr operating in a steady-state mode is as follows:

NO_x: 7.0 ppmvd @ 3% O_2 (or less) – Achieved-in-practice
5.0 ppmvd @ 3% O_2 (or less) – Technologically feasible
SO_x, PM_{10}, VOC: Use of PUC quality natural gas

Based on the "Top-Down BACT Analysis" in Appendix II of this document, the applicant's proposal to comply with 5.0 ppmvd NOx @ 3% O_2 (or less) with an SCR system and use of PUC quality natural gas would satisfy the BACT for NO_x, SO_x, PM_{10}, CO and VOC emissions.

B. Offsets

Offsets are examined on pollutant-by-pollutant basis. The following table summarizes SSPE2, offset thresholds, and whether or not offsets are triggered.

Category	NO_x	SO_x	PM_{10}	CO	VOC
SSPE2 (lb/yr)	45,593	13,835	31,250	180,714	13,320
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	Yes	No	Yes	No	No

<u>NO_x</u>:
Section 4.7.1 of Rule 2201 states that for pollutants with SSPE1 greater than the emission offset threshold levels, emission offsets shall be provided for all increases in Stationary Source emissions, calculated as the differences of post-project Potential to Emit (PE2) and the Baseline Emissions (BE) of all new and modified emissions units, plus all increases in Cargo Carrier emissions. Thus,

EOQ = Σ(PE2 – BE) + ICCE, where

PE2 = Post-Project Potential to Emit (lb/yr)
BE = Baseline Emissions (lb/yr)

ICCE = Increase in Cargo Carrier emissions (lb/yr)

There is no increase in Cargo Carrier emissions from this project. Thus,

EOQ = Σ(PE2 – BE)

Per section 3.8 of Rule 2201, BE can be set equal to PE1 for any Clean Emission Unit (CEU), located at a Major Source, provided that if the unit has a SLC, all units under the SLC also qualify as CEUs. CEU is defined in Section 3.13 of Rule 2201, as an emission unit that is either equipped with an emission control technology with a minimum control efficiency of at least 95% or equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

Effective December 31, 2013, the applicant has proposed to cease the operation of the boilers under permits N-1976-3 and '-5. Since the operation will be ceased before operating the proposed new boiler, PE2 for these units is set equal to zero.

Furthermore, units N-1976-3 and '-5 are found to be clean emission units as they are operating below the achieved-in-practice BACT level of 7 ppmvd NOx @ 3% O_2 based on the latest source test results of July 2010. Therefore, BE is set equal to PE1 for these units.

EOQ = $(PE2 - BE)_{N\text{-}1399\text{-}27} + (PE2 - BE)_{N\text{-}1399\text{-}3} + (PE2 - BE)_{N\text{-}1399\text{-}5}$
= $(PE2 - BE)_{N\text{-}1399\text{-}27} + (PE2 - PE1)_{N\text{-}1399\text{-}3} + (PE2 - PE1)_{N\text{-}1399\text{-}5}$
= (10,869 – 0) lb-NO_x/yr + (0 – 10,696) lb-NO_x/yr + (0 – 6,071) lb-NO_x/yr
= -5,998 lb-NO_x/yr
≈ 0 lb-NO_x/yr

PM_{10}:
Section 4.7.1 of Rule 2201 states that for pollutants with SSPE1 greater than the emission offset threshold levels, emission offsets shall be provided for all increases in Stationary Source emissions, calculated as the differences of post-project Potential to Emit (PE2) and the Baseline Emissions (BE) of all new and modified emissions units, plus all increases in Cargo Carrier emissions. Thus,

EOQ = Σ(PE2 – BE) + ICCE, where

PE2 = Post-Project Potential to Emit (lb/yr)
BE = Baseline Emissions (lb/yr)
ICCE = Increase in Cargo Carrier emissions (lb/yr)

There is no increase in Cargo Carrier emissions from this project. Thus, EOQ $= \Sigma(PE2 - BE)$

Per section 3.8 of Rule 2201, BE can be set equal to PE1 for any Clean Emission Unit (CEU), located at a Major Source, provided that if the unit has a SLC, all units under the SLC also qualify as CEUs. CEU is defined in Section 3.13 of Rule 2201, as an emission unit that is either equipped with an emission control technology with a minimum control efficiency of at least 95% or equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

Effective December 31, 2013, the applicant has proposed to cease the operation of the boilers under permits N-1976-3 and '-5. Since the operation will be ceased before operating the proposed new boiler, PE2 for these units is set equal to zero. Furthermore, units N-1976-3 and '-5 are found to be clean emission units, as they are being fired on natural gas, which is achieved-in-practice BACT standard to reduce PM_{10} emissions. Therefore,

$$
\begin{aligned}
EOQ &= (PE2 - BE)_{N\text{-}1399\text{-}27} + (PE2 - BE)_{N\text{-}1399\text{-}3} + (PE2 - BE)_{N\text{-}1399\text{-}5} \\
&= (PE2 - BE)_{N\text{-}1399\text{-}27} + (PE2 - PE1)_{N\text{-}1399\text{-}3} + (PE2 - PE1)_{N\text{-}1399\text{-}5} \\
&= (7{,}731 - 0)_{N\text{-}1399\text{-}27} + (0 - 4{,}862)_{N\text{-}1399\text{-}3} + (0 - 4{,}194)_{N\text{-}1399\text{-}5} \\
&= -1{,}325 \text{ lb/yr} \\
&\approx 0 \text{ lb/yr}
\end{aligned}
$$

C. Public Notification

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications (SB-288 or Federal)
- New emission units with a PE>100 lb/day of any one pollutant
- Modifications with SSPE1 below an Offset threshold and SSPE2 above an Offset threshold on a pollutant-by-pollutant basis
- New stationary sources with SSPE2 exceeding Offset thresholds
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant

Per section VII.D.6 of this document, this project is a Federal Major Modification. Also, the potential emissions from the new boiler exceed 100 lb/day for CO emissions. Therefore, public notice is required for this project.

D. Daily Emission Limits (DELs)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.17 to restrict a unit's maximum daily emissions. The following DELs will be included in the permit:

Startup/shutdown:

- During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rules 2201, 4305, 4306 and 4320]

- The total duration of startup and shutdown events shall not exceed 4.0 hours in any one day.[District Rule 2201]

- During startup and shutdown, NOx emissions shall not exceed 80 ppmvd @ 3% O_2 or 0.097 lb/MMBtu. [District Rule 2201]

- During startup and shutdown, CO emissions shall not exceed 100 ppmvd @ 3% O_2 or 0.074 lb/MMBtu.[District Rule 2201]

Steady state:

- Except during startup and shutdown, NO_x emissions shall not exceed 5.0 ppmvd @ 3% O_2 or 0.0062 lb/MMBtu, referenced as NO2. [District Rules 2201, 4306 and 4320]

- Except during startup and shutdown, CO emissions shall not exceed 50 ppmvd @ 3% O_2 or 0.037 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

Startup/shutdown/steady state:

- SO_x emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]

- PM_{10} emissions shall not exceed 0.005 lb/MMBtu. [District Rule 2201]

- VOC emissions shall not exceed 0.004 lb/MMBtu, referenced as methane. [District Rule 2201]

- NH_3 emissions from the SCR system shall not exceed 10 ppmvd @ 3% O2. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

Startup/shutdown testing for NOx and CO emissions:
ConAgra will be required to conduct a source test to measure NOx and CO emissions within 60-days of the initial startup.

Steady state testing for measuring NO_x, CO, PM_{10}, VOC and NH_3 emissions:
ConAgra will be required to conduct a source test to measure NO_x, CO, PM_{10}, VOC and NH_3 emissions within 60-days of the initial startup.

Further, a periodic source test to measure NOx, CO and NH_3 emissions will also be required at least once every twelve month. Successful compliance demonstration on two consecutive twelve-month periodic tests may defer the following source test up to thirty-six months. This testing frequency is consistent with the requirements in the boiler Rules 4306 and 4320 and other permitted boilers equipped with SCR systems.

2. Monitoring

ConAgra has proposed to monitor NO_x, CO and O_2 concentrations using portable analyzer on a monthly basis. NH_3 slip from the SCR system is required to be measured using Draeger tubes (or other District approved equivalent technique) at least on a monthly basis at the time NO_x, CO and O_2 measurements are taken.

3. Recordkeeping

ConAgra will be required to maintain all records to verify compliance with the permitted limits. The records are required to be kept for a period of at least 5 years from the date such records is entered in a logbook.

4. Reporting

ConAgra will be required to submit source test reports within 60 days after completing the test.

F. Ambient Air Quality Analysis (AAQA)

Pursuant to Section 4.14 of Rule 2201, an AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. The following table shows the summary of AAQA:

Pollutant	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass	Pass
$PM_{2.5}$	X	X	X	Pass[1]	Pass[1]

[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165(b)(2).

The criteria modeling runs for the proposed new unit indicates that the emissions will not cause or significantly contribute to a violation of the State or National Ambient Air Quality Standards.

G. Compliance Certification

Per Section 4.15 of Rule 2201, "Compliance Certification" and "Alternative Siting Analysis" is required for any project, which constitutes a New Major Source or a Federal Major Modification.

Compliance Certification
The owner of a new Major Source or a source undergoing a Federal Major Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. The compliance certification from the facility is included in Appendix V of this document.

Alternative Siting Analysis
The current project occurs at an existing facility. Since the proposed boiler will provide steam at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

Compliance is expected with this Rule.

Rule 2410 Prevention of Significant Deterioration

Rule 2410 applies to pollutants for which the District is in attainment or for unclasssified, pollutants. The pollutants addressed in the PSD applicability determination are listed as follows:

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO

- PM
- PM10
- Greenhouse gases (GHG): CO2, N2O, CH4, HFCs, PFCs, and SF6

Step 1:
The first step of this PSD evaluation consists of determining whether the facility is an existing PSD Major Source or not. Per section VII.D.3 of this document, this facility is an existing PSD Major Source.

Step 2:
The second step of the PSD evaluation is to determine if the project results in a PSD significant increase.

I. Project Location Relative to Class 1 Area
This facility is not located within 10 km of a Class 1 area, which in this case is "Yosemite National Park" – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

II. Significance of Project Emission Increase Determination
a. Potential to Emit of attainment/unclassified pollutant for New or Modified Emission Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if total potential to emit from all new and modified units is below this threshold, no futher analysis will be needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)						
Category	NO_2	SO_2	CO	PM	PM_{10}	CO_{2e}
N-1976-27-0	5.4	2.2	28.9	3.9	3.9	90,140
PSD Significant Emission Increase Thresholds	40	40	100	25	15	75,000
PSD Significant Emission Increase?	No	No	No	No	No	Yes

As demonstrated above, because the project has a total potential to emit from all new and modified emission units greater than PSD significant emission increase thresholds, further analysis is required to determine if the project has an emission increase greater than the PSD significant emission increase thresholds, see step below.

b. Emission Increase (EI) for Each Attainment/Unclassified Pollutant with a Significant Emission Increase vs PSD Significant Emission Increase Thresholds

In this step, the emission increase for each attainment/unclassified pollutant is compared to the PSD significant emission increase thresholds, and if the emission increase for each attainment pollutant is below this threshold, no futher analysis is needed.

For the existing emissions units, the increase in emissions is calculated as follows:

EI = PAE – BAE - UBC

Where: PAE = Projected Actual Emissions, and
BAE = Baseline Actual Emissions
UBC = Unused baseline capacity

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

EI from the proposed new 176.5 MMBtu/hr boiler is summarized in the following table.

Pollutant	EI (lb/yr)
NOx	10,869
SOx	4,401
PM_{10}	7,731
CO	57,730
CO2e	90,140

The project's combined total emission increases are compared to the PSD significant emissions increase thresholds in the following table.

PSD Significant Emission Increase Determination: Emission Increase (tons/year)						
Category	NO_2	SO_2	CO	PM	PM_{10}	CO_{2e}
Emission Increases (only)	5.4	2.2	28.9	3.9	3.9	90,140
PSD Significant Emission Increase Thresholds	40	40	100	25	15	75,000
PSD Significant Emission Increase?	No	No	No	No	No	Yes

As demonstrated in the table above, the project emission increases exceed the PSD threshold significant emission increase thresolds for CO2e emissions. Therefore, further analysis is required to determine if the project has a net emissions incrase greater than the PSD significant emissions increase threshold for this specific pollutant.

c. Net Emission Increase for Each Attainment/Unclassified Pollutant with a Significant Emission Increase vs PSD Significant Emission Increase Thresholds

The net emission increase needs to be calculated only for the (those) pollutant(s) with a PSD significant emission increase.

All creditable emission increases and decreases at the stationary source occurring within the past five years (including those projects not related to the subject project) are calculated to determine if the project results in a significant net emission increase. In this calculation, only creditable emission decreases and increases are counted:

- Emission changes that resulted in the project being a Federal Major Modification (as defined in Rule 2201) or subject to a PSD permit are not creditable.
- Emission decreases that resulted in the issuance of emission reduction credits are not creditable.

The creditable increases and decreases in emissions during the five years preceding the expected date of commencement of construction of the proposed project must be calculated.

The expected date of commencement of construction would be sometime in January 2014. Therefore, the 5-year CO2 analysis for the projects undertaken between 2009 and 2013 period is performed:

2009:
No ATC projects were found in this year.

2010:
No ATC projects were found in this year.

2011:
Project N1110448
The company has replaced boiler N-1976-13 with an equivalent heat input boiler. No emissions decrease due to this project

Project N1110502
The company has proposed to increase bean processing rate. No changes to the GHG emissions.

Project N1113624
Rule 4320 compliance project to modify boilers N-1976-4-10 and '-5-8. No changes to the GHG emissions.
2012:
Project N1120784
This project and associated permit is cancelled in the permits database.

2013
Project N1132242
Temporarily use 184 MMBtu/hr burner in an existing boiler under N-1946-4. This project is not expected to result any permanent decrease in GHG emissions.

Project N1132615
Rule 4320 compliance project to modify boilers N-1976-6. No changes to the GHG emissions.

Project N1132682
This project involves temporary use of a rental boiler when boiler N-1976-6 is down for maintenance and or repair. This project is not expected to result any permanent decrease in GHG emissions.

The CO2e emissions are creditable from the proposed shutdown of boilers N-1976-3 and '-5, as these credits were not accounted in any projects during the 2009-2013 time period. These CO2e credits are estimated as follows:

<u>N-1399-3</u>
Per emissions inventory data of 2011 and 2012, the average fuel use was 317.5 MMscf/yr. Therefore,

PE = (116.6 lb-CO2e/MMBtu)(317.5 MMscf/yr)(1,000 Btu/scf)(ton/2,000 lb)
= 18,510 tons-CO2e/yr

<u>N-1399-5</u>
Per emissions inventory data of 2011 and 2011, the average fuel use was 63.8 MMscf/yr. Therefore,

PE = (116.6 lb-CO2e/MMBtu)(63.8 MMscf/yr)(1,000 Btu/scf)(ton/2,000 lb)
= 3,720 tons-CO2e/yr

Total = 18,510 tons-CO2e/yr + 3,720 tons-CO2e/yr
= 22,230 tons-CO2e/yr

Summary:

Year	Emissions Increase (tons-CO2e/yr)	Emissions decrease (tons-CO2e/yr)
2009	0	0
2010	0	0
2011	0	0
2012	0	0
2013	90,140	22,230
Net Emissions Increase	67,910 (90,140-22,230)	
Significant Net Emissions Increase Threshold	75,000	

As demonstrated in the table above, the project does not result in a significant net emission increase for CO2e. As such, the project is not subject to Rule 2410 due to a significant net emission increase and no further discussion is required.

Rule 2520 Federally Mandated Operating Permits

ConAgra is a Major Source for NO_x and GHG emissions. Therefore, this facility is subject to the requirements of this rule. The proposed project is a "significant modification" to the Title V permit, as the project is a Federal Major Modification. ConAgra has requested to issue the ATC with COC. The following conditions will be included in the permit:

- This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201]

- Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

In accordance with Rule 2520, the application meets the procedural requirements of section 11.4 by including:

- A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs and

- The source's suggested draft permit (Appendix I of this document) and

- Certification by a responsible official that the proposed modification meets the criteria for use of major permit modification procedures and a request that such procedures be used (Appendix V of this document).

Section 5.3.4 of this rule requires the permittee shall file an application for administrative permit amendments prior to implementing the requested change except when allowed by the operational flexibility provisions of section 6.4 of this rule. ConAgra Foods is expected to notify the District by filing TV Form-008 upon implementing the ATC. The District Compliance Division is expected to submit a change order to implement ATC into Permit to Operate (PTO).

Compliance is expected with this Rule.

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998."

Based on the calculations in the worksheets in Appendix IV of this document, this facility is not becoming a Major HAP Source (i.e. PE >10 tons/yr for single HAP, PE > 25 tons/yr for combined HAPs). Therefore, this facility is not subject to the requirements of this Rule.

Rule 4001 New Source Performance Standards

40 CFR Part 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

<u>Section 60.40b - Applicability and delegation of authority</u>
This subpart applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr.

The new boiler is likely to be constructed sometime in 2014. This unit is subject to the requirements of this subpart.

<u>Section 60.42b - Standard for sulfur dioxide (SO2)</u>
Section 60.42b(k)(1)(2) states that the units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 0.32 lb/MMBtu heat input or less are exempt from the SO_2 emissions in paragraph (k)(1) of this section (i.e., 0.2 lb-SO_2/MMBtu, or 92% reduction of potential SO_2 rate and 1.2 lb-SO_2/MMBtu).

The boilers will be fired on natural gas fuel containing a maximum of 1.0 gr-S/100 scf, which equates to 0.00285 lb/MMBtu. Therefore, this unit is exempt from the SO_2 emissions in paragraph (k)(1) of this section. The following condition will be included in the permit:

- The unit shall only be fired on PUC-quality natural gas with a sulfur content of no greater than 1.0 grains (gr) of sulfur per 100 standard cubic feet (scf) of natural gas. [District Rules 2201 and 4320, 40 CFR 60.42b(k)(1)(2)]

<u>Section 60.43b - Standard for particulate matter (PM)</u>
This section does not list PM emission standards for natural gas fired steam generating units.

<u>Section 60.44b - Standard for nitrogen oxides (NO_x)</u>
Section 60.44b(a) states that except as provided in paragraphs (k) and (l) of this section, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of 0.1 lb/MMBtu for low heat release rate (≤ 70,000 Btu/hr-ft^3 of furnace volume) or 0.2 lb/MMBtu for high release rate (> 70,000 Btu/hr-ft^3 of furnace volume).
Section 60.44b(h) states for the purposes of paragraph (i) of this section, the NOx standards under this section apply at all times including periods of startup, shutdown, or malfunction.

Section 60.44b(i) state that compliance with an applicable limit is determined on a 30-day rolling average basis.

The new boiler will be permitted to emit 5.0 ppmvd @ 3% O2 (or less) during steady-state (80 ppmvd @ 3% O_2 during startup/shutdown period). These limits are significantly less than 82 ppmvd @ 3% O_2 (equates to 0.1 lb/MMBtu) most stringent NOx limit for low heat release rate units. Thus, compliance is expected with this section. The following condition(s) will be included in the permit:

- For 40 CFR Part 60 Subpart Db purposes, NOx emissions shall not exceed 0.1 lb/MMBtu for low heat release units (70,000 Btu/hr-ft3 of furnace volume or less) and 0.2 lb/MMBtu for high heat release units (greater than 70,000 Btu/hr-ft3 of furnace volume) on a 30-day rolling average basis. NOx standard shall apply at all times including periods of startup, shutdown, or malfunction. The permittee shall maintain record of the furnace volume, which is defined as the volume bounded by the front furnace wall where the burner is located, the furnace side waterfall, and extending to the level just below or in front of the first row of convection pass tubes. [40 CFR 60.44b(a), 60.44b(h), 60.44b(i)]

Section 60.45b - Compliance and performance test methods and procedures for sulfur dioxide

Section 60.45b(j) states the owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts per section 60.49b(r) which requires the supplier to certify that the gaseous fuel meets the definition of natural gas. In lieu of receipts, the owner or operator may develop and submit a site-specific fuel analysis for review and approval per information in section 60.49b(r)(2).

This facility uses PUC quality natural gas supplied by PG&E, which has a transportation agreement to deliver gas with maximum sulfur content of 1.0 gr/100 scf (actual: 0.3 to 0.5 gr/100 scf, based on source testing)[4]. Therefore, the following condition will enforce compliance with this section:

- The owner or operator shall either obtain fuel receipts (such as a valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets definition of natural gas (as defined in 40 CFR 60.41b) and the applicable sulfur limit (i.e., 1.0 gr-S/100 scf), or demonstrate that the combusted gas is provided from a PUC or FERC regulated source, or monitor the sulfur content within 60 days of initial startup and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 4320, 40 CFR 60.45b(j), 60.49b(r)(2)]

Section 60.46b - Compliance and performance test methods and procedures for particulate matter and nitrogen oxides

Section 60.46 (c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

The proposed boiler does not qualify the requirements under paragraphs (g) and (h). Section 60.46b(e) states compliance with the NOx emission limits shall be conducted using continuous system for monitoring NOx under section 60.48(b).

Section 60.46b(e)(1) states NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. The following condition(s) will be included in the permit:

[4]The sulfur content in PUC regulated natural gas is taken from District Policy APR-1720.

- For the initial compliance test under 40 CFR Part 60 Subpart Db, NOx emissions shall be monitored for 30 successive steam generating unit operating days and the 30-day average emission rate shall be used to determine compliance with the NOx emission standard under 40 CFR 60.44b (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)). The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. [40 CFR 60.46b(e)(1)]

Section 60.46b(e)(4) Following the date on which the initial 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 has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days. The following condition(s) will be included in the permit:

- Following the initial compliance test under 40 CFR Part 60 Subpart Db, the operator shall upon request determine compliance with the NOx standard under 40 CFR 60.44 (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)) through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days. [40 CFR 60.46b(e)(4)]

<u>§ 60.47b Emission monitoring for sulfur dioxide</u>
Per section 60.48b(f), the proposed units are not subject to the requirements of this section if the owner or operator maintains fuel records described in §60.49b(r). Refer to the discussion under section 60.45b above.

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides
Section 60.48b(b) states that except as provided under paragraphs (g), (h) and (i), the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section (i.e., install continuous emissions monitoring system (CEMS) for measuring NOx and O2 concentrations).

Section 60.48b(g) states that the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall: (1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or (2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c).

ConAgra Foods is not proposing to install CEMS to monitor and record NOx and O2 concentrations, instead, the facility has proposed to use a portable analyzer that meets specifications in District policy SSP-1105 (4/28/2008), on a monthly basis. The following condition(s) will be included in the permit:

- The owner or operator shall monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c) and approved by the District. [40 CFR 60.48b(g)(2)]

Section 60.48b(j) states that the owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), or (6) of this section is not required to install or operate a continuous opacity metering system (COMS) if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility 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 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day

average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) 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.

(B) 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).

(C) 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).

(D) 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.

(ii) 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.

(iii) 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.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) 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.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part; or

(6) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates 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.

The boiler will be fired on natural gas fuel with 1.0 gr-S/100 scf or less (equates to 0.00285 lb-SO2/MMBtu); therefore, COMS is not required.

§ 60.49b Reporting and recordkeeping requirements
Section 60.49b(a) states that the owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the 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 §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

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

(4) Notification that an emerging technology will be used for controlling emissions of SO2.

- The owner or operator shall submit notification of the date of initial startup and the annual capacity factor at which the owner or operator anticipate to operate this unit. [40 CFR Part 60.49b(a)(3)]

Note that the design heat input capacity is listed in the equipment description, and the unit will not be equipped with any emerging technology to reduce SO2 emissions. Therefore, notification on both of these items is not required.

Section 60.49b(b) states that the owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in Appendix B of this part.

ConAgra may use portable analyzer to monitor NOx and O2 concentrations for the 30 consecutive days to determine compliance with the standards in this subpart. Data collected during that period will be required to be submitted to the District within 60 days after completing the test. The following condition(s) will be included in the permit:

- The owner or operator shall submit the data from initial performance test to demonstrate compliance with 40 CFR Part 60 Subpart Db within 60 days after completing the initial test. [40 CFR 60.49b(b)]

Section 60.49b(c) states that the owner or operator of each affected facility subject to the NO_x standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOX emission rates (i.e., ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NOX emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

The following condition will be included in the permit:

- The owner or operator shall develop and submit a plan, within 360 days of initial startup of the unit, to predict the hourly NOx emissions. The plan shall: (1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (i.e., ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O2 level); (2) Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and (3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g). If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. [40 CFR Part 60.49b(c)]

Section 60.49(d)(1) states the owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. The following condition(s) will be included in the permit:

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [40 CFR 60.49b(d)(1)]

- The owner or operator shall maintain records of the amount of fuel combusted during each day in this unit. [40 CFR 60.49b(d)(1)]

- The owner or operator shall maintain records of the annual capacity factor on a monthly basis. The annual capacity factor shall be determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [40 CFR 60.49b(d)(1)]

Section 60.49(g) states that except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

The following condition(s) will be included in the permit; note that this condition does not include item (8), (9) or (10) as the proposed installation does not include CEMS to monitor NOx and O2 concentrations.

- The owner or operator shall maintain records and submit a written report each calendar quarter to the District containing the following information for each steam generating unit operating day: (1) Calendar date; (2) The average hourly NOx and CO emission rates (expressed as NO2) (ppmvd @ 3% O2 and lb/MMBtu heat input) measured or predicted; (3) The 30-day average NOx emission rates (lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days; (4) Identification of the steam generating unit operating days when the calculated 30-day average NOx emission rates are in excess of the NOx emissions standards under 40 CFR 60.44b (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)), with the reasons for such excess emissions as well as a description of corrective actions taken; (5) Identification of the steam generating unit operating days when the average hourly NOx and CO emission rates are in excess of the NOx and CO limits (startup, shutdown and steady state) in this permit, with the reason for such excess emissions as well as a description of corrective actions taken; (6) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken; (7) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data; (8) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted; and (11) A negative declaration when no excess emissions occurred. The report is due on the 30th day following the end of the calendar quarter. [District Rules 1080, 2201, 4305, 4306 and 4320, 40 CFR 60.49b(g), 40 CFR 60.49b(i), and 40 CFR 60.49b(w)]

Section 60.49b(h) states that the owner or operator is required to submit excess emission reports for any excess emissions that occurred during the reporting period. Item 4 in the requirement 60.49b(g), given in the above condition, would satisfy an on-going compliance with this section.

Section 60.49b(i) states the owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section. The condition under section 60.49b(g) would satisfy an on-going compliance with this section.

Section 60.49b(o) requires that all records shall be maintained by the owner or operator for a period of 2 years following the date of such record.

The District will require the owner or operator to maintain records of required monitoring data and support information for a period of at least five years from the date of data entry of each record. The following condition(s) will be included in the permits:

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 1070, 2201, 4305, 4306, and 4320, 40 CFR 60.49b(o)]

Section 60.49b(v) states the owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format. The following condition(s) will be included in the permits:

- The owner or operator of an affected facility may submit electronic quarterly reports in lieu of submitting the written reports. The format of each quarterly electronic report shall be coordinated with the District. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this permit was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the District to obtain their agreement to submit reports in this alternative format. [District Rule 1080 and 40 CFR 60.49b(v)]

Section 60.49b(w) states the reporting period for the reports required under this subpart is each 6 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 reports are required to be submitted on a quarterly basis. Therefore, compliance is expected with this section. Please refer to the condition under section 60.48b(g) above.

Compliance is expected with this Regulation.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Pursuant to Section 2.0, "All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein". Therefore, the requirements of this rule apply to this facility. However, there are no applicable requirements for a non-major HAP source. As discussed under Rule 2550, this facility is not a major HAP source; therefore, no actions are necessary to determine compliance with this rule.

Rule 4101 Visible Emissions

Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringlemann 1 or equivalent to 20% opacity. The following condition will be placed on each permit:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Compliance is expected with this Rule.

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants, which could cause injury, detriment, nuisance or annoyance to the public. The following condition will be placed on each permit:

- No air contaminant shall be released into the atmosphere, which causes a public nuisance. [District Rule 4102]

California Health & Safety Code 41700 - Health Risk Assessment

District Policy APR 1905 - Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District performs an analysis to determine the possible impact to the nearest resident or worksite. The risk management review analysis summary is as follows:

Risk Management Review Summary			
Categories	Unit 27-0	Project Totals	Facility Totals
Prioritization Score	0.35	0.35	>1
Acute Hazard Index	0.00	0.00	0.00
Chronic Hazard Index	0.00	0.00	0.01
Maximum Individual Cancer Risk	8.48E-07	8.48E-07	1.80E-06
T-BACT Required?	No		
Special Permit Conditions?	Yes		

The acute and chronic indices are below 1.0; and the cancer risk is less than 1.0 in a million. In accordance with the District's Risk Management Policy, the project is approved without toxic Best Available Control Technology (T-BACT). To ensure that human health risks will not exceed District allowable levels; the following condition will be included in the permit:

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Compliance is expected with this Rule.

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

PM_{10} emissions	= 0.883 lb-PM_{10}/hr (0.005 lb/MMBtu x 176.5 MMBtu/hr)
Fraction (lb-PM_{10}/lb-PM)	= 100 %
Exhaust Temperature	= 250°F
Exhaust flow rate	= 51,905 acfm
Moisture in exhaust	= 7% (assumed)

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(0.883\frac{lb-PM}{hr}\right)\left(7{,}000\frac{gr-PM}{lb-PM}\right)\left(\frac{hr}{60\ min}\right)}{\left(51{,}905\frac{ft^3}{min}\right)\left(\frac{459.67+60}{459.67+250}\right)(1-0.07)} = 0.003\frac{gr-PM}{dscf}$$

The following condition will be listed in the permit:

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Compliance is expected with this Rule.

Rule 4301 Fuel Burning Equipment

The requirements of section 5.0 are as follows:

- Combustion contaminates (TSP) - Not to exceed 0.1 gr/dscf @ 12% CO_2 and 10 lb/hr.
- SO_x emissions - Not to exceed 200 lb/hr
- NO_x emissions - Not to exceed 140 lb/hr

NOx (lb/hr) = (0.097 lb/MMBtu)(176.5 MMBtu/hr) = 17.1 lb/hr
SOx (lb/hr) = (0.00285 lb/MMBtu)(176.5 MMBtu/hr) = 0.5 lb/hr

$$PM\left(\frac{gr}{dscf}\right) = \frac{PM\ Emissions\left(\frac{lb-PM}{MMBtu}\right)\times 7{,}000\ \frac{gr-PM}{lb-PM}}{F_{factor\ CO_2}\left(\frac{dscf}{MMBtu}\right)\times\left(\frac{100\%}{12\%}\right)}$$

$$= \frac{\left(0.005\ \frac{lb-PM}{MMBtu}\right)\left(7{,}000\ \frac{gr-PM}{lb-PM}\right)}{\left(1{,}024.2\ \frac{dscf}{MMBtu}\right)\left(\frac{100\%}{12\%}\right)}$$

$$= 0.004\ \frac{gr-PM}{dscf}$$

The proposed emissions are below the limits of this Rule; therefore, compliance is expected.

Rule 4304 Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters

Pursuant to District Rules 4305 and 4306, Section 6.3.1, boilers are required to be tested at least once every 12-months. Gaseous fuel fired units demonstrating compliance on two consecutive 12-month source tests may defer the following source test for up to 36 months. During 36-month source testing interval, the operator shall tune the boiler according to section 5.2.1 (tune up at least once each calendar year by qualified technician in accordance with Rule 4304). Tune-ups required by Sections 5.2.1 and 6.3.1 do not need to be performed for units that operate and maintain an APCO approved CEMS or an APCO approved Alternate Monitoring System where the applicable emission limits are periodically monitored.

NOx, CO and O_2 concentrations from the boiler will be measured using a portable analyzer monitor on a monthly basis. This monitoring scheme is approved under District Policy SSP-1105; therefore, boiler tune-ups are not required.

Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2

Since the emission limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3

Section 2.0 - Applicability
This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour.

The heat input rate to the boiler is greater than 5 MMBtu/hr. Therefore, this unit is subject to the requirements of this rule.

Section 5.0 - Requirements
Section 5.1.1 limits NO_x and CO emissions to 9 ppmvd @ 3% O_2 and 400 ppmvd @ 3% O_2 respectively.

The applicant has proposed to achieve 5.0 ppmvd NO_x @ 3% O2 (or less) and 50 ppmvd CO @ 3% O_2 (or less) for the boiler being permitted in this project. Since the proposed limits are below the rule limits, compliance is expected with this section.

Section 5.2 lists the requirements for boilers limited to a heat input rate of less than 9 billion Btu per calendar year. The boilers will not be limited to a heat input rate of less than 9 billion Btu per calendar year. Therefore, this section is not applicable.

Section 5.3 states that the NO_x and CO emission limits shall not apply to this unit during start-up and shutdown period provided that the duration of each start-up or each shutdown is not greater than 2.0 hours, and the emission control system is utilized during these periods. An operator may submit a request to allow more than two hours for each startup or each shutdown provided the operator meets all of the conditions specified in sections 5.3.3.1 to 5.3.3.3.

The proposed duration of each startup and shutdown will be 2.0 hours. The following condition(s) will be included in the permit:

- Duration of each startup and each shutdown shall not exceed 2.0 hours. [District Rule 4306 and 4320]

Section 5.4.1 requires the operator to install and maintain a non-resettable, totalizing mass or volumetric flow meter for the units, which simultaneous uses gaseous and liquid fuels and is subject to the requirements of Section 5.1. The applicant is proposing to use gaseous fuel only. Therefore, they are not required to install and maintain a fuel flow meter due to this section.

Section 5.4.2 requires that the units subject to District Rule 4306, Section 5.1 emissions limits, shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring. In order to satisfy the requirements of District Rule 4306, the applicant has proposed to use pre-approved alternate monitoring scheme "H" of District Policy SSP-1105, which requires periodic monitoring of NO_X, CO, NH_3 and O_2 exhaust emissions concentrations. The following condition(s) will be included in the permit:

- The permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 2201, 4305, 4306 and 4320]

- If either the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201, 4305, 4306 and 4320]

- All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 2201, 4305, 4306 and 4320]

- Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 2201, 4305 and 4306]

- The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320]

Section 5.5.1 states the operator of any unit have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limit. The following condition(s) will be included in the permit:

- The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320]

Section 5.5.2 requires all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. The following condition(s) will be included in the permit:

- All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305, 4306 and 4320]

Section 5.5.3 requires that all CEMS data shall be averaged over a period of 15-consecutive minutes to demonstrate compliance with the applicable emission limits in this rule. The proposed boiler emissions will not be measured using CEMS system; therefore, this section is not applicable.

Section 5.5.4 requires emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five readings evenly spaced out over the 15-consecutive-minute period. The following condition(s) will be included in the permit:

- All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 2201, 4305, 4306 and 4320]

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. The following condition(s) will be included in the permit:

- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

Section 6.0 – Administrative Requirements
Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. The following condition(s) will be included in the permit:

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 1070, 2201, 4305, 4306, and 4320, 40 CFR 60.49b(o)]

Section 6.2 identifies the test methods for determining higher heating value of fuel, NO_x, CO, O_2, stack gas velocities, and stack gas moisture content. The following conditions will be listed on each permit. The following condition(s) will be included in the permit:

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- NOx emissions for source test purposes shall be determined using EPA Method 7E or CARB Method 100 on a ppmv basis. [District Rules 4305, 4306 and 4320]
- CO emissions for source test purposes shall be determined using EPA Method 10 or CARB Method 100. [District Rules 4305, 4306 and 4320]
- Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 4305, 4306 and 4320]

In addition, the ammonia slip is required to be measured using BAAQMD Method ST-1B. The following condition will be included in permit N-1399-24:

- Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rule 2201]

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Units that demonstrate compliance on two consecutive 12-month source tests may defer the following 12-month source test for up to 36 months (no more than 30 days before or after the required 36-month source test date). During the 36-month source testing interval, the operator shall tune the unit in accordance with the provisions of Section 5.2.1, and shall monitor, on a monthly basis, the unit's operational characteristics recommended by the manufacturer to ensure compliance with the applicable emission limits specified in Sections 5.1 or 5.2.3. Tune-ups required by Sections 5.2.1 and 6.3.1 do not need to be performed for units that operate and maintain an APCO approved CEMS or an APCO approved Alternate Monitoring System where the applicable emission limits are periodically monitored.

NOx, CO and O2 concentrations will be measured on monthly basis using portable analyzer. Therefore, no periodic tune-ups are required. The following conditions will be listed in permit N-1399-24:

- Source testing to measure steady state NO_x, CO, PM_{10}, VOC and NH_3 emissions shall be conducted within 60-days of the initial startup. [District Rules 2201, 4305, 4306 and 4320]

- Source testing to measure NOx, CO and NH_3 emissions during steady state operation shall be conducted at least once every 12 months. After demonstrating compliance on 2 consecutive annual source tests, the unit shall be tested not less than once every 36 months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every 12 months. [District Rules 4305, 4306 and 4320]

Section 6.3.2 lists compliance testing procedure for units that represent a group of units. The heat input rate of the boilers at this site significantly varies from one boiler to another; therefore, group testing cannot be considered.

Section 6.4 discusses emission control plan (ECP). The permit application for the proposed new boiler satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is necessary.

Section 7.0 – Compliance Schedule
This new boiler is expected to be operating in compliance with this rule after initial startup. Therefore, no further discussion is required.

Compliance is expected with this Rule.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters greater than 5.0 MMBtu/hr

Section 2.0 - Applicability
Section 2.0 states that this rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour.

The heat input rate to the proposed boiler is greater than 5 MMBtu/hr. Therefore, this unit is subject to the requirements of this rule.

Section 5.0 – Requirements
Section 5.1 states that an operator of a unit(s) subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

- Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or

- Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or

- Comply with the applicable Low-use Unit requirements of Section 5.5.

The facility had chosen to comply with the emission limits specified in Section 5.2 and 5.4. These limits are summarized below:

NOx: 7 ppmvd @ 3% O2
CO: 400 ppmvd @ 3% O2
Particulate Matter: Use PUC-quality natural gas, commercial propane, butane, or LPG, or combination of such gases with fuel sulfur content of 5 grains/100 scf or less.

The applicant has proposed the following limits:

NOx: 5.0 ppmvd @ 3% O2 (or less);
CO: 50 ppmvd @ 3% O2 (or less);
Particulate Matter: Use PUC-quality natural gas.

Therefore, compliance is expected with this section.

Section 5.3 states that the NO_x and CO emission limits shall not apply to this unit during start-up and shutdown period provided that the duration of each start-up or each shutdown is not greater than 2.0 hours, and the emission control system is utilized during these periods.

The duration of each startup and startup is 2.0 hours. The following condition(s) will be included in the permit:

- Duration of each startup and each shutdown shall not exceed 2.0 hours. [District Rule 4306 and 4320]

Section 5.7 discusses monitoring provisions to comply with NO_x and CO limits. These provisions are similar to the provisions in Rule 4306 (discussed previously).

Section 5.7.6 requires the operator to provide annual fuel sulfur content analysis. The following conditions will satisfy the requirements of this section:

- The owner or operator shall either obtain fuel receipts (such as a valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets definition of natural gas (as defined in 40 CFR 60.41b) and the applicable sulfur limit (i.e., 1.0 gr-S/100 scf), or demonstrate that the combusted gas is provided from a PUC or FERC regulated source, or monitor the sulfur content within 60 days of initial startup and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 4320, 40 CFR 60.45b(j), 60.49b(r)(2)]

- Fuel sulfur content shall be determined using EPA Method 11 or EPA Method 15 or District, CARB and EPA approved alternative methods. [District Rule 4320]

Section 5.8 discusses compliance determination. The requirements in this section are similar to the requirements in Rule 4306 (discussed previously).

Section 6.0 – Administrative Requirements
Recordkeeping requirements of this Rule are similar to that of the Rule 4306. Please refer to section 6.0 of Rule 4306.

Section 7.0 – Compliance Schedule
This section refers to "Authority to Construct" and "Compliance Deadline" dates for existing units. The proposed unit is a new boiler, which is expected to comply with the requirements of this rule.

Compliance is expected with this Rule.

Rule 4351 Boilers, Steam Generators, and Process Heaters – Phase 1

Since the emission limits of District Rule 4306 and 4320 and all other requirements are equivalent or more stringent than this Rule, compliance with District Rule 4306 and 4320 requirements will satisfy requirements of District Rule 4351.

Rule 4801 Sulfur Compounds

Section 3.1 states that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding a concentration of two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2) at the point of discharge on a dry basis averaged over 15 consecutive minutes.

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\frac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from the proposed boiler are based on 1.0 gr-S/100 scf, equivalent to 0.00285 lb/MMBtu. Since these emissions are less than 2.9 lb/MMBtu, it is expected that the boiler will operate in compliance with this Rule.

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

On December 17, 2009, the District's Governing Board adopted the District's policy for addressing GHG emission impacts when the District is Lead Agency under CEQA and approved the District's guidance document for use by other agencies when addressing GHG impacts as lead agencies under CEQA. Under this policy, the District's determination of significance of project-specific GHG emissions is founded on the principal that projects with GHG emission reductions consistent with AB 32 emission reduction targets are considered to have a less than significant impact on global climate change.

The California Air Resources Board (ARB) adopted a Cap and Trade regulation as part one of the strategies identified for AB 32. This Cap and Trade regulation is a statewide plan for reducing or mitigating GHG emissions from targeted industries. Facilities subject to the Cap and Trade regulation are subject to an industry-wide cap on overall GHG emissions. Any growth in emissions must be accounted for under that cap such that a corresponding and equivalent reduction in emissions must occur to allow any increase. The District finds that compliance with ARB's Cap and Trade regulation would avoid or substantially lessen the impact of project-specific GHG emissions on global climate change.

Facility N-1976 is subject to the Cap and Trade regulation. The District therefore concludes that the project would have a less than significant individual and cumulative impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15031 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. RECOMMENDATION

Issuance of the ATC N-1976-27-0 is recommended upon addressing comments from the applicant, EPA, ARB and the public.

X. BILLING INFORMATION

Permit #	Fee Schedule	Fee Description	Previous Fee Schedule
N-1976-27-0	3020-02H	176.5 MMBtu/hr	None

APPENDICES

Appendix I: Draft Authority to Construct Permit
Appendix II: Top-Down BACT Analysis
Appendix III: Risk Management Review and Ambient Air Quality Analysis
Appendix IV: HAP Emission Calculations
Appendix V: Compliance Certification

Appendix I
Draft Authority to Construct Permit

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-1976-27-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CONAGRA FOODS
MAILING ADDRESS: ATTN: REGIONAL ENVIRONMENTAL MANAGER
554 S YOSEMITE AVE
OAKDALE, CA 95361

LOCATION: 554 S YOSEMITE AVE
OAKDALE, CA 95361

EQUIPMENT DESCRIPTION:
176.5 MMBTU/HR CLEAVER BROOKS MODEL NB-500D-100 NATURAL GAS-FIRED WITH A CLEAVER BROOKS MODEL NATCOM LOW NOX BURNER AND A C&C PANASIA (OR EQUIVALENT MANUFACTURER) SELECTIVE CATALYTIC REDUCTION SYSTEM

CONDITIONS

1. The permittee shall cease the operation of boilers under permits N-1976-3 and N-1976-5 by December 31, 2013. [District Rule 2201] Federally Enforceable Through Title V Permit
2. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
3. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. Particulate matter emissions from this unit shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
6. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services
N-1976-27-0 Jan 21 2014 8:13AM – KAHLONJ Joint Inspection NOT Required

7. The unit shall only be fired on PUC-quality natural gas with a sulfur content of no greater than 1.0 grains (gr) of sulfur per 100 standard cubic feet (scf) of natural gas. [District Rules 2201 and 4320, 40 CFR 60.42b(k)(1)(2)] Federally Enforceable Through Title V Permit
8. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
9. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [40 CFR 60.49b(d)(1)] Federally Enforceable Through Title V Permit
10. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
11. Duration of each startup and each shutdown shall not exceed 2.0 hours. [District Rule 4306 and 4320] Federally Enforceable Through Title V Permit
12. The total duration of startup and shutdown period shall not exceed 4.0 hours in any one day. [District Rule 2201] Federally Enforceable Through Title V Permit
13. The total duration of startup and shutdown period shall not exceed 80 hours during any 12 consecutive month rolling period. [District Rule 2201] Federally Enforceable Through Title V Permit
14. During startup and shutdown, NOx emissions shall not exceed 80 ppmvd @ 3% O2 or 0.097 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
15. During startup and shutdown, CO emissions shall not exceed 100 ppmvd @ 3% O2 or 0.074 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
16. Except during startup and shutdown, NOx emissions shall not exceed 5.0 ppmvd @ 3% O2 or 0.0062 lb/MMBtu, referenced as NO2. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
17. Except during startup and shutdown, CO emissions shall not exceed 50 ppmvd @ 3% O2 or 0.037 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
18. SOx emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
19. PM10 emissions shall not exceed 0.005 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
20. VOC emissions shall not exceed 0.004 lb/MMBtu, referenced as methane. [District Rule 2201] Federally Enforceable Through Title V Permit
21. NH3 emissions from the SCR system shall not exceed 10.0 ppmvd @ 3% O2. [District Rule 2201] Federally Enforceable Through Title V Permit
22. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit
23. Source testing to measure startup and shutdown NOx and CO emissions shall be conducted within 60 days of initial startup. [District Rule 2201] Federally Enforceable Through Title V Permit
24. Source testing to measure steady state NOx, CO, PM10, VOC and NH3 emissions shall be conducted within 60 days of initial startup. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
25. Source testing to measure NOx, CO and NH3 emissions during steady state operation shall be conducted at least once every 12 months. After demonstrating compliance on 2 consecutive annual source tests, the unit shall be tested not less than once every 36 months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every 12 months. [District Rule 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
26. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

27. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

28. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

29. NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

30. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

31. Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

32. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rule 1081] Federally Enforceable Through Title V Permit

33. Source testing to measure PM10 shall be conducted using either: EPA Method 201 or 201A, and 202; or CARB Method 5 in combination with 501. Should the applicant decided to use different methodology, the methodology must be approved by the District prior to its use. [District Rule 2201] Federally Enforceable Through Title V Permit

34. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emissions limit provided the results include both the filterable and condensable (back half) particulate, and that all particulate matter is assumed to be PM10. Source testing to measure concentrations of total particulate emissions shall be conducted using EPA method 5. [District Rule 2201] Federally Enforceable Through Title V Permit

35. Source testing to measure VOC emissions shall be conducted using EPA Method 18 or 25A. Should the applicant decided to use different methodology, the methodology must be approved by the District prior to its use. [District Rule 2201] Federally Enforceable Through Title V Permit

36. Fuel sulfur content shall be determined using EPA Method 11 or Method 15. [District Rule 4320] Federally Enforceable Through Title V Permit

37. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

38. The permittee shall monitor and record the stack concentration of NOx, CO, NH3 and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications. NH3 monitoring shall be conducted utilizing gas detection tubes (Draeger brand or District approved equivalent). Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless it has been performed within the last month. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

39. If either the NOx, CO or NH3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the permitted levels the permittee shall return the emissions to compliant levels as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer or the ammonia monitoring equipment continue to show emission limit violations after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation that is subject to enforcement action has occurred. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

40. All NOx, CO, O2 and ammonia emission readings shall be taken with the unit operating at conditions representative of normal operation or under the conditions specified in the Permit to Operate. The NOx, CO and O2 analyzer as well as the NH3 emission monitoring equipment shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Analyzer readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

41. Ammonia emissions readings shall be conducted at the time the NOx, CO and O2 readings are taken. The readings shall be converted to ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, NH3 and O2 measurements, (2) the O2 concentration in percent by volume and the measured NOx, CO and NH3 concentrations corrected to 3% O2, (3) make and model of the portable analyzer, (4) portable analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions at or below the acceptable levels. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

43. The permittee shall maintain record of the following items: (1) date; (2) duration of each startup (hours); (3) duration of each shutdown (hours); (4) total start-up and shutdown durations per day (hour/day); (5) total start-up and shutdown durations per month (hours/month); (6) total startup and shutdown duration in a 12 consecutive month period. [District Rule 2201, 4306 and 4320] Federally Enforceable Through Title V Permit

44. The owner or operator shall either obtain fuel receipts (such as a valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets definition of natural gas (as defined in 40 CFR 60.41b) and the applicable sulfur limit (i.e., 1.0 gr-S/100 scf), or demonstrate that the combusted gas is provided from a PUC or FERC regulated source, or monitor the sulfur content within 60 days of initial startup and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 4320, 40 CFR 60.45b(j), 60.49b(r)(2)] Federally Enforceable Through Title V Permit

45. For 40 CFR Part 60 Subpart Db purposes, NOx emissions shall not exceed 0.1 lb/MMBtu for low heat release units (70,000 Btu/hr-ft3 of furnace volume or less) and 0.2 lb/MMBtu for high heat release units (greater than 70,000 Btu/hr-ft3 of furnace volume) on a 30-day rolling average basis. NOx standard shall apply at all times including periods of startup, shutdown, or malfunction. The permittee shall maintain record of the furnace volume, which is defined as the volume bounded by the front furnace wall where the burner is located, the furnace side waterfall, and extending to the level just below or in front of the first row of convection pass tubes [40 CFR 60.44b(a), 60.44b(h), 60.44b(i)] Federally Enforceable Through Title V Permit

46. For the initial compliance test under 40 CFR Part 60 Subpart Db, NOx emissions shall be monitored for 30 successive steam generating unit operating days and the 30-day average emission rate shall be used to determine compliance with the NOx emission standard under 40 CFR 60.44b (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)). The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. [40 CFR 60.46b(c)(1)] Federally Enforceable Through Title V Permit

47. Following the initial compliance test under 40 CFR Part 60 Subpart Db, the operator shall upon request determine compliance with the NOx standard under 40 CFR 60.44 (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)) through the use of a 30-day performance test. During periods when performance tests are not requested, NOx emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NOx emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NOx emission data for the preceding 30 steam generating unit operating days. [40 CFR 60.46b(e)(4)] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

48. The owner or operator shall monitor steam generating unit operating conditions and predict NOx emission rates as specified in a plan submitted pursuant to §60.49b(c) and approved by the District. [40 CFR 60.48b(g)(2)] Federally Enforceable Through Title V Permit

49. The owner or operator shall submit notification of the date of initial startup and the annual capacity factor at which the owner or operator anticipate to operate this unit. [40 CFR Part 60.49b(a)(3)] Federally Enforceable Through Title V Permit

50. The owner or operator shall submit the data from initial performance test to demonstrate compliance with 40 CFR Part 60 Subpart Db within 60 days after completing the initial test. [40 CFR 60.49b(b)] Federally Enforceable Through Title V Permit

51. The owner or operator shall develop and submit a plan, within 360 days of initial startup of the unit, to predict the hourly NOx emissions. The plan shall: (1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOx emission rates (i.e., ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O2 level); (2) Include the data and information that the owner or operator used to identify the relationship between NOx emission rates and these operating conditions; and (3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g). If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. [40 CFR Part 60.49b(c)] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain records of the amount of fuel combusted during each day in this unit. [40 CFR 60.49b(d)(1)] Federally Enforceable Through Title V Permit

53. The owner or operator shall maintain records of the annual capacity factor on a monthly basis. The annual capacity factor shall be determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [40 CFR 60.49b(d)(1)] Federally Enforceable Through Title V Permit

54. The owner or operator shall maintain records and submit a written report each calendar quarter to the District containing the following information for each steam generating unit operating day: (1) Calendar date; (2) The average hourly NOx and CO emission rates (expressed as NO2) (ppmvd @ 3% O2 and lb/MMBtu heat input) measured or predicted; (3) The 30-day average NOx emission rates (lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days; (4) Identification of the steam generating unit operating days when the calculated 30-day average NOx emission rates are in excess of the NOx emissions standards under 40 CFR 60.44b (0.1 lb/MMBtu for low heat release units (i.e., 70,000 Btu/hr-ft3 of furnace volume, or less), or 0.2 lb/MMBtu for high heat release units (i.e., greater than 70,000 Btu/hr-ft3 of furnace volume)), with the reasons for such excess emissions as well as a description of corrective actions taken; (5) Identification of the steam generating unit operating days when the average hourly NOx and CO emission rates are in excess of the NOx and CO limits (startup, shutdown and steady state) in this permit, with the reason for such excess emissions as well as a description of corrective actions taken; (6) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken; (7) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data; (8) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted; and (11) A negative declaration when no excess emissions occurred. The report is due on the 30th day following the end of the calendar quarter. [District Rules 1080, 2201, 4305, 4306 and 4320, 40 CFR 60.49b(g), 40 CFR 60.49b(i), and 40 CFR 60.49b(w)] Federally Enforceable Through Title V Permit

55. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 1070, 2201, 4305, 4306, and 4320, and 40 CFR 60.49b(o)] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

56. The owner or operator of an affected facility may submit electronic quarterly reports in lieu of submitting the written reports. The format of each quarterly electronic report shall be coordinated with the District. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this permit was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the District to obtain their agreement to submit reports in this alternative format. [District Rule 1080 and 40 CFR 60.49b(v)] Federally Enforceable Through Title V Permit

Appendix II
Top Down BACT Analysis

Top-Down BACT Analysis for NOx

Step 1: Identify All Possible Control Technologies

The District considers the following NOx emissions limits:

Achieved-in-Practice:
7.0 ppmvd @ 3% O_2 (0.008 lb/MMBtu)

Technologically Feasible:
5.0 ppmvd @ 3% O_2 (0.0062 lb/MMBtu)

Alternate Basic Equipment:
None

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. 5.0 ppmvd @ 3% O_2 (0.0062 lb/MMBtu) - Technologically Feasible
2. 7.0 ppmvd @ 3% O_2 (0.011 lb/MMBtu) - Achieved-in-Practice

Step 4: Cost Effectiveness Analysis

Option 1: 5.0 ppmvd @ 3% O_2 (0.0062 lb/MMBtu)
The applicant has proposed to emit 5.0 ppmvd NOx @ 3% O2 or less from the new boiler; therefore, cost effectiveness analysis is not required.

Step 5: Select BACT
BACT requirement is to achieve 7.0 ppmvd NO_x @ 3% O_2 (or less) concentrations. However, the applicant has proposed to achieve 5.0 ppmvd NOx @ 3% O_2 (or less).

Top-Down BACT Analysis for SOx, PM10 and VOC

Step 1: Identify All Possible Control Technologies

The following techniques are considered to reduce SOx, PM_{10} or VOC emissions.

Achieved-in-Practice:
Use natural gas, or LPG fuel

Technologically Feasible:
None

Alternate Basic Equipment:
None

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. use of natural gas or LPG fuel

Step 4: Cost Effectiveness Analysis

There is no technologically feasible option in Step 3. Therefore, cost-effectiveness analysis is not required.

Step 5: Select BACT

BACT requirement is to use natural gas or LPG fuels to reduce SOx, PM_{10} and VOC emissions.

Appendix III
Risk Management Review and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review
REVISED

To:	Jag Kahlon - Permit Services
From:	Cheryl Lawler - Permit Services
Date:	January 16, 2014
Facility Name:	ConAgra Foods
Location:	544 S. Yosemite Avenue, Oakdale
Application #(s):	N-1976-27-0
Project #:	N-1132542

A. RMR SUMMARY

RMR Summary			
Categories	**Natural Gas Boiler (Unit 27-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	0.35	0.35	>1
Acute Hazard Index	0.00	0.00	0.01
Chronic Hazard Index	0.00	0.00	0.01
Maximum Individual Cancer Risk	**8.48E-07**	**8.48E-07**	1.80E-06
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit 27-0

1. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102] N

B. RMR REPORT

I. Project Description

Technical Services received a request on January 13, 2014, to re-run an Ambient Air Quality Analysis (AAQA) and a Risk Management Review (RMR) for a new 176.5 MMBtu/hr natural gas boiler. The boiler will be equipped with a Selective Catalytic Reduction (SCR) system to reduce NO_x emissions. This boiler will replace the existing boilers (111 MMBtu/hr & 63 MMBtu/hr).

II. Analysis

Toxic emissions for the boiler were calculated using 2001 Ventura County Air Pollution Control District emission factors for natural gas fired external combustion. Ammonia emission rates from the SCR system were calculated and supplied by the processing engineer. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905-1, March 2, 2001), risks from the proposed project were prioritized using the procedures in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEART's database. The prioritization score for the project was less than 1.0 (see RMR Summary Table); however, the facility's total cumulative prioritization scores totaled to greater than one. Therefore, a refined Health Risk Assessment was required and performed. AERMOD was used, with point source parameters outlined below, and 5-year meteorological data from Modesto to determine maximum dispersion factors at the nearest residential and business receptors. These dispersion factors were input into the HARP model to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 27-0			
Source Type	Point	**Closest Receptor Distance (m)**	152.4
Natural Gas Process Rates (mmscf)	0.18 hr 1550 yr	**Closest Receptor Type**	Residence & Business
Ammonia Emission Rates (lbs)	0.741 hr 6,494 yr	**Project Location**	Urban
Stack Height (m)	15.24	**Stack Diameter (m)**	1.52
Stack Gas Temperature (K)	394	**Stack Gas Velocity (m/sec)**	13.43

Technical Services also performed modeling for criteria pollutants NOx, SOx, CO, and PM_{10}; as well as the RMR for the engine. The emission rates used for criteria pollutant modeling were 10,869 lb/yr NOx, 4,406 lb/yr SOx, 57,730 lb/yr CO, and 7,731 lb/yr PM_{10}.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Natural Gas Boiler	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[1]	Pass[1]

*Results were taken from the attached PSD spreadsheet.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusions

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with the boiler is less than the 1 in a million threshold. In accordance with the District's Risk Management Policy, the project is approved **without** Toxic Best Available Control Technology (T-BACT).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Attachments:

Revised RMR Request Form
Prioritization
Risk Results
AAQA Results
Facility Summary

Appendix IV
HAP Emission Calculations

Summary of HAP Emissions

Permit #	Description	HAPs (lb/yr)
N-1976-3-7	111 MMBtu/hr natural gas-fired boiler	24
N-1976-4-9	196 MMBtu/hr natural gas-fired boiler	23
N-1976-5-7	63 MMBtu/hr natural gas-fired boiler	34
N-1976-6-8	184 MMBtu/hr natural gas-fired boiler	39
N-1976-14-2	102 bhp diesel-fueled emergency IC engine	0
N-1976-17-2	115 bhp diesel-fueled emergency IC engine	0
N-1976-18-2	116 bhp diesel-fueled emergency IC engine	0
N-1976-21-2	Bean receiving, precleaning and storage operation	0
N-1976-22-2	Bean cleaning and processing operation	0
N-1976-24-0	86 MMBtu/hr natural gas-fired boiler	47
N-1976-26-0	Temporary burner replacement for N-1976-4	--
N-1976-27-0	176.5 MMBtu/hr natural gas-fired boiler	38
N-1976-28-0	99.9 MMBtu/hr rental boiler temporary unit N-1976-4, '-6 and 24	--
	Total (lb/yr):	205
	Total (tons/yr):	**0.10**

Potential HAP Emissions from "N-1976-3-7"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr) [2]	Maximum Annual Emissions (lb/yr) [3]	Maximum Annual Emissions (tpy)
Acetaldehyde	9.00E-07	9.99E-05	1	0.0
Acrolein	8.00E-07	8.88E-05	1	0.0
Benzene	1.70E-06	1.89E-04	2	0.0
1,3-Butadiene	n/a	--	---	--
Ethyl benzene	2.00E-06	2.22E-04	2	0.0
Formaldehyde	3.60E-06	4.00E-04	4	0.0
Hexane	1.30E-06	1.44E-04	1	0.0
Naphthalene	3.00E-07	3.33E-05	0	0.0
PAHs excluding naphthalene	1.00E-07	1.11E-05	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	7.80E-06	8.66E-04	8	0.0
Xylene	5.80E-06	6.44E-04	6	0.0
Total			**24**	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment greater than 100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf

2. Hourly emissions = EF (lb/MMBtu) x 111 (MMBtu/hr)

3. Annual emissions = EF (lb/MMBtu) x 111 (MMBtu/hr) x 8,760 (hr/yr)

Potential HAP Emissions from "N-1976-4-9"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr) [2]	Maximum Annual Emissions (lb/yr) [3]	Maximum Annual Emissions (tpy)
Acetaldehyde	9.00E-07	1.76E-04	1	0.0
Acrolein	8.00E-07	1.57E-04	1	0.0
Benzene	1.70E-06	3.33E-04	2	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	2.00E-06	3.92E-04	2	0.0
Formaldehyde	3.60E-06	7.06E-04	3	0.0
Hexane	1.30E-06	2.55E-04	1	0.0
Naphthalene	3.00E-07	5.88E-05	0	0.0
PAHs excluding naphthalene	1.00E-07	1.96E-05	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	7.80E-06	1.53E-03	7	0.0
Xylene	5.80E-06	1.14E-03	5	0.0
Total			**23**	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment greater than 100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf

2. Hourly emissions = EF (lb/MMBtu) x 196 (MMBtu/hr)

3. Annual emissions = EF (lb/MMBtu) x 943,272 (MMBtu/yr)

Potential HAP Emissions from "N-1976-5-7"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr) [2]	Maximum Annual Emissions (lb/yr) [3]	Maximum Annual Emissions (tpy)
Acetaldehyde	3.10E-06	1.95E-04	2	0.0
Acrolein	2.70E-06	1.70E-04	1	0.0
Benzene	5.80E-06	3.65E-04	3	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	6.90E-06	4.35E-04	4	0.0
Formaldehyde	1.23E-05	7.75E-04	7	0.0
Hexane	4.60E-06	2.90E-04	3	0.0
Naphthalene	3.00E-07	1.89E-05	0	0.0
PAHs	1.00E-07	6.30E-06	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	2.65E-05	1.67E-03	15	0.0
Xylene	6.40E-08	4.03E-06	0	0.0
Total			**34**	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment 10-100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf
2. Hourly emissions = EF (lb/MMBtu) x 63 (MMBtu/hr)
3. Annual emissions = EF (lb/MMBtu) x 63 (MMBtu/hr) x 8,760 (hr/yr)

Potential HAP Emissions from "N-1976-6-8"

HAP	Emission Factor (lb/MMBtu)(1)	Maximum Hourly Emissions (lb/hr) (2)	Maximum Annual Emissions (lb/yr) (3)	Maximum Annual Emissions (tpy)
Acetaldehyde	9.00E-07	1.66E-04	1	0.0
Acrolein	8.00E-07	1.47E-04	1	0.0
Benzene	1.70E-06	3.13E-04	3	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	2.00E-06	3.68E-04	3	0.0
Formaldehyde	3.60E-06	6.62E-04	6	0.0
Hexane	1.30E-06	2.39E-04	2	0.0
Naphthalene	3.00E-07	5.52E-05	0	0.0
PAHs excluding naphthalene	1.00E-07	1.84E-05	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	7.80E-06	1.44E-03	13	0.0
Xylene	5.80E-06	1.07E-03	9	0.0
Total			**39**	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment greater than 100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf

2. Hourly emissions = EF (lb/MMBtu) x 184 (MMBtu/hr)

3. Annual emissions = EF (lb/MMBtu) x 184 (MMBtu/hr) x 8,760 (hr/yr)

Potential HAP Emissions from "N-1976-14-2"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]	Maximum Annual Emissions (tpy)
Acetaldehyde	7.67E-04	5.68E-04	0.0	0.0
Acrolein	9.25E-05	6.85E-05	0.0	0.0
Benzene	9.33E-04	6.90E-04	0.0	0.0
1,3-Butadiene	3.91E-05	2.89E-05	0.0	0.0
Ethyl benzene	--	--	--	--
Formaldehyde	1.18E-03	8.73E-04	0.0	0.0
Hexane	n/a	--	--	--
Naphthalene	8.48E-05	6.28E-05	0.0	0.0
PAHs	8.32E-05	6.16E-05	0.0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	4.09E-04	3.03E-04	0.0	0.0
Xylene	2.85E-04	2.11E-04	0.0	0.0
Total			**0**	**0.0**

Notes:

1. The emission are taken from AP-42 Table 3.3-2 (10/96)
2. Hourly emissions= EF (lb/MMBtu) x 0.74 MMBtu/hr; 5.41 gal/hr x 0.137 MMBtu/gal = 0.74 MMBtu/hr
3. Annual emissions = Hourly emissions (lb/hr) x 30 (hr/yr)

Potential HAP Emissions from "N-1976-17-2"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]	Maximum Annual Emissions (tpy)	
Acetaldehyde	7.67E-04	6.44E-04	0.1	0.0	
Acrolein	9.25E-05	7.77E-05	0.0	0.0	
Benzene	9.33E-04	7.84E-04	0.1	0.0	
1,3-Butadiene	3.91E-05	3.28E-05	0.0	0.0	
Ethyl benzene	--	--	--	--	
Formaldehyde	1.18E-03	9.91E-04	0.1	0.0	
Hexane	n/a	--	--	--	
Naphthalene	8.48E-05	7.12E-05	0.0	0.0	
PAHs	8.32E-05	6.99E-05	0.0	0.0	
Propylene Oxide	n/a	--	--	--	
Toluene	4.09E-04	3.44E-04	0.0	0.0	
Xylene	2.85E-04	2.39E-04	0.0	0.0	
Total			**0**	**0.0**	

Notes:
1. The emission are taken from AP-42 Table 3.3-2 (10/96)
2. Hourly emissions= EF (lb/MMBtu) x 0.84 MMBtu/hr; 6.1 gal/hr x 0.137 MMBtu/gal = 0.84 MMBtu/hr
3. Annual emissions = Hourly emissions (lb/hr) x 100 (hr/yr)

Potential HAP Emissions from "N-1976-18-2"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]	Maximum Annual Emissions (tpy)
Acetaldehyde	7.67E-04	6.44E-04	0.1	0.0
Acrolein	9.25E-05	7.77E-05	0.0	0.0
Benzene	9.33E-04	7.84E-04	0.1	0.0
1,3-Butadiene	3.91E-05	3.28E-05	0.0	0.0
Ethyl benzene	--	--	--	--
Formaldehyde	1.18E-03	9.91E-04	0.1	0.0
Hexane	n/a	--	--	--
Naphthalene	8.48E-05	7.12E-05	0.0	0.0
PAHs	8.32E-05	6.99E-05	0.0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	4.09E-04	3.44E-04	0.0	0.0
Xylene	2.85E-04	2.39E-04	0.0	0.0
Total			**0.3**	**0.0**

Notes:

1. The emission are taken from AP-42 Table 3.3-2 (10/96)
2. Hourly emissions= EF (lb/MMBtu) x 0.84 MMBtu/hr; 6.1 gal/hr x 0.137 MMBtu/gal = 0.84 MMBtu/hr
3. Annual emissions = Hourly emissions (lb/hr) x 100 (hr/yr)

Potential HAP Emissions from "N-1976-24-0"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]	Maximum Annual Emissions (tpy)
Acetaldehyde	3.10E-06	2.67E-04	2	0.0
Acrolein	2.70E-06	2.32E-04	2	0.0
Benzene	5.80E-06	4.99E-04	4	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	6.90E-06	5.93E-04	5	0.0
Formaldehyde	1.23E-05	1.06E-03	9	0.0
Hexane	4.60E-06	3.96E-04	3	0.0
Naphthalene	3.00E-07	2.58E-05	0	0.0
PAHs	1.00E-07	8.60E-06	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	2.65E-05	2.28E-03	20	0.0
Xylene	6.40E-08	5.50E-06	0	0.0
Total			47	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment 10-100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf
2. Hourly emissions = EF (lb/MMBtu) x 86 (MMBtu/hr)
3. Annual emissions = EF (lb/MMBtu) x 86 (MMBtu/hr) x 8,760 (hr/yr)

Potential HAP Emissions from "N-1976-27-0"

HAP	Emission Factor (lb/MMBtu)[1]	Maximum Hourly Emissions (lb/hr)[2]	Maximum Annual Emissions (lb/yr)[3]	Maximum Annual Emissions (tpy)
Acetaldehyde	9.00E-07	1.59E-04	1	0.0
Acrolein	8.00E-07	1.41E-04	1	0.0
Benzene	1.70E-06	3.00E-04	3	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	2.00E-06	3.53E-04	3	0.0
Formaldehyde	3.60E-06	6.35E-04	6	0.0
Hexane	1.30E-06	2.29E-04	2	0.0
Naphthalene	3.00E-07	5.30E-05	0	0.0
PAHs excluding naphthalene	1.00E-07	1.77E-05	0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	7.80E-06	1.38E-03	12	0.0
Xylene	5.80E-06	1.02E-03	9	0.0
Total			**38**	**0.0**

Notes:

1. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment greater than 100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf

2. Hourly emissions = EF (lb/MMBtu) x 176.5 (MMBtu/hr)

3. Annual emissions = EF (lb/MMBtu) x 176.5 (MMBtu/hr) x 8,760 (hr/yr)

Appendix V
Compliance Certification

ConAgra Foods
Food you love

ConAgra Foods
554 S. Yosemite Avenue
Oakdale, CA 95361

TEL: 209-847-0321
FAX: 209-848-7386

August 23, 2013

Mr. Jagmeet Kahlon
San Joaquin Valley Air Pollution Control District
4800 Enterprise Way
Modesto CA 95356-8718

RE: Compliance Statement for ConAgra Foods

Dear Mr. Kahlon:

In accordance with Rule 2201, Section 4.15, "Additional Requirements for New Major Sources and Federal Major Modifications," ConAgra Foods is pleased to provide this compliance statement regarding its proposed installation of a new boiler replacing two existing boilers [project N-1132542].

All major stationary sources in California owned or operated by ConAgra Foods, or by any entity controlling, controlled by, or under common control with ConAgra Foods, and which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards. These sources include one or more of the following facilities:

Facility #1: ConAgra Foods, Inc., 554 Yosemite Avenue, Oakdale, CA 95361

Facility #2: ConAgra Foods, Inc., 16429 W Kamm Ave., Helm, CA 93627

Facility #3: National Pretzel Company, Inc., 7607 W Goshen Avenue, Visalia, CA 93291

Facility #4: ConAgra Snack Foods (David & Sons Sunflower Seeds), 5214 E Pine Avenue, Fresno, CA 93727

Facility #5: ConAgra Foods, Inc., 2201 E 7th Street, Oakland, CA 94606

Facility #6: ConAgra Foods, Inc., 2020 East Steel Road, Colton, CA 92324

ConAgra Foods
Food you love

ConAgra Foods
554 S. Yosemite Avenue
Oakdale, CA 95361

TEL: 209-847-0321
FAX: 209-848-7386

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Please contact me if you have any questions regarding this certification.

Sincerely,

ConAgra Foods

Jeff Schultz

Jeff Schultz
Plant Engineering & Environmental Manager
209 848-7295
Email jeff.schultz@conagrafoods.com

San Joaquin Valley
Unified Air Pollution Control District

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

[X] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

COMPANY NAME: ConAgra Foods	FACILITY ID: N - 1976
1. Type of Organization: [X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility	
2. Owner's Name: ConAgra Foods	
3. Agent to the Owner:	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

(X) Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

(X) Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

(X) Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

(X) Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Jeff Schultz

Signature of Responsible Official

8/15/13

Date

Jeff Schultz

Name of Responsible Official (please print)

Plant Engg & Env Manager

Title of Responsible Official (please print)