San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

OCT 05 2017

Mr. Douglas Findley
Land O Lakes Inc
400 South M St
Tulare, CA 93274

Re: Proposed ATC / Certificate of Conformity (Significant Mod)
District Facility # S-525
Project # 1173420

Dear Mr. Findley:

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. The project authorizes a new boiler.

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. Leonard Scandura, Permit Services Manager, at (661) 392-5500.

Thank you for your cooperation in this matter.

Sincerely,

Arnaud Marjollet
Director of Permit Services

Enclosures

cc: Tung Le, 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
New Boiler

Facility Name:	Land O Lakes Inc	Date:	September 26, 2017
Mailing Address:	400 South M St Tulare, CA 93274	Engineer:	Richard Edgehill
		Lead Engineer:	Richard Edgehill
Contact Person:	Douglas Findley		
Telephone:	(559) 687-6653		
Fax:	(559) 685-6930		
E-Mail:	dwfindley@landolakes.com		
Application #(s):	S-525-51-1		
Project #:	1173420		
Deemed Complete:	September 25, 2017		

I. Proposal

Land O Lakes, Inc (LOL) recently received an Authority to Construct for the installation of a new 182 MMBtu/hr natural gas-fired boiler (ATC S-525-51-0, project 1153671). In this project, LOL has requested to reauthorize ATC '-51-0 using different banked emissions reductions credits (ERCs) to provide offsets. No other changes are proposed.

ATC S-525-51-0 (base document) and current PTO S-525-2-8, which will be canceled, are included in **Attachment I**.

Emissions from the boiler will trigger BACT, offsets, and public notice.

LOL received their Title V Permit on January 14, 1999. This modification can be classified as a Title V Significant Modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct. LOL must apply to administratively amend their Title V permit.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (2/18/16)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 4001	New Source Performance Standards (4/14/99) – Subpart Db
	Part 64 - Compliance Assurance Monitoring (CAM)

Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04) – Subpart DDDDD – **not applicable** - source is not a major HAPs source Subpart JJJJJ – **not applicable** - source is area HAPs source (40 CFR 60.11194) but unit is a gas fired boiler (63.11237) and is exempt by 40 CFR 63.11195(e)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase II (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase III (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 4801	Sulfur Compounds (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 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

The facility is located at 400 South M St, Tulare. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

S-525-2

Boiler #5 (S-525-2), to be deleted by this project, is a 71.727 MMBtu/hr natural gas fired boiler with 30 billion Btu/yr natural gas usage limit.

New Boiler S-525-51

The facility is proposing to install a new Babcock and Wilcox 182 MMBtu/hr boiler. LOL proposes to operate this unit as a load following boiler for the facility to generate steam required for various processes at the facility.

As a part of this project, LOL is shutting down Boiler #5 (S-525-2). This new boiler will supplement the steam demand required for the facility's operations. The new boiler will be equipped with SCR and is expected to achieve 5 ppm NO_x at 3% O_2.

Manufacturer's information on the boiler and SCR are included in **Attachment II**.
NOx and CO monitoring will be done using a Predictive Emission Monitoring System (PEMS). PEMS predicts NOx and CO emissions based on a mathematical model with operational conditions such as fuel flow, pressure and temperature as model input parameters.

The PEMS must satisfy the requirements of EPA's Performance Specification 16 (PS 16) – Specifications and Test Procedures for Predictive Emission Monitoring Systems (PEMS) in Stationary Sources and be approved by the District and/or EPA.

Notification and use of PEMS is required as stated in the following ATC condition:

Permittee shall submit to the District or EPA Regional Administrator for approval a plan (PEMS plan) that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b and Rule 4320. This plan shall be submitted to the District or EPA Regional Administrator for approval within 360 days of the initial startup of the affected facility. [40 CFR Subpart Db, 40 CFR Part 64] Y

PEMs 30-day Training Period

Applicant has requested a 30-day "shakedown period" for training of the PEMS (i.e. measuring NOx and CO emissions with CEMS while simultaneously measuring a variety of operational parameters). During this time the boiler will be operated with and without the SCR catalyst to allow the PEMs model to be "trained" over a wide range of exhaust concentrations. During PEMS training, proposed NOx emissions will be limited to 20 ppmv @ 3% O_2 and startup and shutdown time durations will be limited to 12 hr and 9 hr, to allow for startup and shutdown PEMS training.

EPA Specification 16 Requirements

Periodic performance checks are required to be conducted to ensure long-term quality of the PEMs data. These include annual RATA (Source Testing) and quarterly Relative Accuracy Audit (RAA) testing (every quarter except when RATA is conducted). The periodic testing must be conducted with established protocol including a fixed number of runs at 3 levels and minimum number of variables for use in the statistical correlations. The PEMS must be designed such that defective sensors can be determined manually or automatically on a daily basis. Recertification of the PEMS must be done with failure of annual and/or quarterly performance tests and/or if process operational parameters change significantly since the initial certification.

Information on the Rockwell Software with Model Predictive Control is included in **Attachment III**.

V. Equipment Listing

S-525-51-1: 182 MMBTU/HR BABCOCK AND WILCOX COMPANY NATURAL GAS FIRED BOILER WITH COEN/TODD VARIFLAME LOW NOX BURNER, CATASTAK SCR SYSTEM, AND A PREDICTIVE EMISSION MONITORING SYSTEM (PEMS)

VI. Emission Control Technology Evaluation

The new boiler will be fired on natural gas and be equipped with SCR to limit the NOx emissions to 5 ppmvd at 3% O2.

VII. General Calculations

A. Assumptions

- Operation is 24 hr/day, 365 days per year.
- Natural gas heating value: 1000 Btu/scf
- The new boiler is fired exclusively on PUC-regulated natural gas.
- Natural Gas Heating Value: 1,000 Btu/scf (District Practice)
- F-Factor for Natural Gas: 8,578 dscf/MMBtu corrected to 60°F (40 CFR 60, Appendix B)
- NOx daily emissions are established (maximum) during the 30 day training period (20 ppmv NOx @ 3% O_2).
- Annual emissions during the 1st year (PEMS training) are calculated using the steady state NOx limit of 5 ppmv NOx @ 3% O_2 which will be accomplished by curtailed operational time or use of more ammonia to lower NOx emissions.

B. Emission factors

S-525-2 – 71.7 MMBtu/hr existing boiler

Pollutant	Pre-Project Emission Factors (EF1)			Source
NO_X	36 lb-NO_X/MMscf	0.036 lb-NO_X/MMBtu	30 ppmvd NO_X (@ 3%O_2)	Current Permit
SO_X	2.85 lb-SO_X/MMscf	0.00285 lb-SO_X/MMBtu		District Policy APR 1720
PM10	3.0 lb-PM10/MMscf	0.003 lb-PM10/MMBtu		Current Permit
CO	60 lb-CO/MMscf	0.06 lb-CO/MMBtu	81 ppmvd CO* (@ 3%O_2)	Current Permit
VOC	20.0 lb-VOC/MMscf	0.02 lb-VOC/MMBtu	47.3 ppmvd VOC** (@ 3%O_2)	Current Permit

*0.06 lb/MMBtu MBtu/8578 dscf @ 0% O_2 x [(20.9 – 3) dscf @ 0% O_2/20.9 dscf @ 3% O_2 x lbmol/28 lb x 379 ft^3/lbmol x 10^6 = 81 ppmv @ 35 O2

**0.02 lb/MMBtu MBtu/8578 dscf @ 0% O_2 x [(20.9 – 3) dscf @ 0% O_2/20.9 dscf @ 3% O_2 x lbmol/16 lb x 379 ft^3/lbmol x 10^6 = 47.3 ppmv @ 3% O2

S-525-51 - 182 MMBtu/hr New Boiler

Pollutant	Emission Factor	Unit	Source
NOx	5, 0.0061	ppmv @3%O2, lb/MMBtu	SCR Manufacturer Guarantee, based on 5 ppmv @ 3% O2
SOx	0.00185	lb/MMBtu	District Standard for natural gas
PM10	0.0076	lb/MMBtu	AP-42 Chapter 1.4, 2-5-14 email
CO	50, 0.037	ppmv @ 3% O2, lb/MMBtu	Boiler Manufacturer Guarantee
VOC	13, 0.0055	ppm, lb/MMBtu	AP-42

*(5 ft^3/10^6 ft^3 @ 3% O_2 x [(20.9 – 0)/(20.9 - 3)] ft^3 @19% O_2)/ ft^3 @ 0% O_2
x 8,578 ft^3 @ 0% O_2/MMBtu x (46 lb/lbmol)(lbmol/379.5 scf) = 0.0061 lb/MMBtu
(50 ft^3/10^6 ft^3 @ 3% O_2 x [(20.9 – 0)/(20.9 - 3] ft^3 @19% O_2)/ ft^3 @ 0% O_2
x 8,578 ft^3 @ 0% O_2/MMBtu x (28 lb/lbmol)(lbmol/379.5 scf) = 0.037 lb/MMBtu
(13 ft^3/10^6 ft^3 @ 3% O_2 x [(20.9 – 0)/(20.9 - 3] ft^3 @19% O_2)/ ft^3 @ 0% O_2
x 8,578 ft^3 @ 0% O_2/MMBtu x (16 lb/lbmol)(lbmol/379.5 scf) = 0.0055 lb/MMBtu

30 day PEMs Training Period

*(20 ft^3/10^6 ft^3 @ 3% O_2 x [(20.9 – 0)/(20.9 - 3)] ft^3 @19% O_2)/ ft^3 @ 0% O_2
x 8,578 ft^3 @ 0% O_2/MMBtu x (46 lb/lbmol)(lbmol/379.5 scf) = 0.0243 lb/MMBtu

C. Calculations

1. Pre-Project Potential to Emit (PE1)

S-525-2 (to be canceled)

Pollutant	Daily Pre-Project Potential to Emit (PE1)										
	Emission Factors			Heat input			Hours per day			Daily PE1	
NO_X	0.036	(lb-NO_X/MMBtu)	x	71.7	(MMBtu/hr)	x	24	(hr/day)	=	61.9	(lb-NO_X/day)
SO_X	0.00285	(lb-SO_X/MMBtu)	x	71.7	(MMBtu/hr)	x	24	(hr/day)	=	4.9	(lb-SO_X/day)
PM_{10}	0.0030	(lb-PM_{10}/MMBtu)	x	71.7	(MMBtu/hr)	x	24	(hr/day)	=	5.2	(lb-PM_{10}/day)
CO	0.060	(lb-CO/MMBtu)	x	71.7	(MMBtu/hr)	x	24	(hr/day)	=	103.2	(lb-CO/day)
VOC	0.0200	(lb-VOC/MMBtu)	x	71.7	(MMBtu/hr)	x	24	(hr/day)	=	34.4	(lb-VOC/day)

Pollutant	Annual Pre-Project Potential to Emit (PI PE1						
	Emission Factors			Annual Max Heat input		Annual PE1	
NO_X	0.0360	(lb-NO_X/MMBtu)	x	30	(billion Btu/year)	= 1,080	(lb-NO_X/year)
SO_X	0.00285	(lb-SO_X/MMBtu)	x	30	(billion Btu/year)	= 86	(lb-SO_X/year)
PM_{10}	0.0030	(lb-PM_{10}/MMBtu)	x	30	(billion Btu/year)	= 90	(lb-PM_{10}/year)
CO	0.0600	(lb-CO/MMBtu)	x	30	(billion Btu/year)	= 1,800	(lb-CO/year)
VOC	0.0200	(lb-VOC/MMBtu)	x	30	(billion Btu/year)	= 600	(lb-VOC/year)

<u>S-525-51</u>

Since this is a new emissions unit, PE1 = 0 for all pollutants.

2. Post Project Potential to Emit (PE2)

S-525-51

Pollutant	Daily PE2			
	EF1 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/day)	Daily PE2 (lb/day)
NO_X	0.006	182	24	see below
SO_X	0.00285	182	24	12.4
PM_{10}	0.0076	182	24	33.2
CO	0.037	182	24	161.6
VOC	0.0055	182	24	24.0

Pollutant	Annual PE2			
	EF1 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/year)	Annual PE2 (lb/year)
NO_X	0.006	182	8,760	9,725
SO_X	0.00285	182	8,760	4,544
PM_{10}	0.0076	182	8,760	12,117
CO	0.037	182	8,760	58,990
VOC	0.0055	182	8,760	8,769

30 day (720 hr) "shakedown period"

NOx: 0.0243 lb NOx/MMBtu x 182 MMBtu/hr x 24 hr/day = 106.1 lb/day

Emissions profiles are included in **Attachment IV.**

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

Pursuant to District Rule 2201, the SSPE1 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 (AER) that have occurred at the source, and which have not been used on-site.

SSPE1 (lb/year)					
Permit Unit/ERC	NO_X	SO_X	PM_{10}	CO	VOC
SSPE1*Existing Permit Units	51,949	8,839	106,681	244,800	12,834
ERC S-3284-1					2,062
ERC S-3625-1					214
ERC S-3326-2	808				
ERC S-3625-2	2339				
ERC S-1734-3				45,199	
ERC S-3625-3				13,183	
ERC S-3625-4			2,706		
ERC S-3625-5		21			
Total$_{ERC}$	3,147	21	2,706	58,382	2,276
SSPE1	55,096	8,860	109,387	303,182	15,110

*SSPE calculator 9-18-15, no outstanding ATCs

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

The SSPE 2 was calculated above and is listed in the following table:

SSPE2 (lb/year)					
Permit Unit/ERC*	NO_X	SO_X	PM_{10}	CO	VOC
SSPE1 Existing Permit Units	51,949	8,839	106,681	244,800	12,834
S-525-2	-1,080	-86	-90	-1,800	-600
S-525-51	9,725	4,544	12,117	58,990	8,769
SSPE2Permit Unit	60,594	13,297	118,708	301,990	21,003
~~ERC S-3284-1~~					~~2,062~~
~~ERC S-3625-1~~					~~214~~
~~ERC S-3326-2~~	~~808~~				
~~ERC S-3625-2~~	~~2339~~				
ERC S-1734-3				45,199	
ERC S-3625-3				13,183	
~~ERC S-3625-4~~			~~2,706~~		
~~ERC S-3625-5~~		~~21~~			
Total$_{ERC}$	0	0	0	58,382	0
SSPE2	60,594	13,297	118,708	360,372	21,003

*ERCs withdrawn for this project are not included in SSPE2 (lined out text)

5. 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)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1 permit unit	51,949	8,839	106,681	106,681	244,800	12,834
SSPE2 permit unit	60,594	13,297	118,708	118,708	301,990	21,003
Major Source Threshold	20,000	140,000	140,000	200,000	200,000	20,000
Major Source?	Yes	No	No	No	Yes	Yes

Note: PM2.5 assumed to be equal to PM10 for natural gas combustion

As seen in the table above, the facility is an existing Major Source for NOx, CO, and VOC.

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)(iii) i.e. Category V fossil-fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input. Therefore, the PSD Major Source threshold is 100 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	26	6.4	4.4	122	53	53
PSD Major Source Thresholds	100	100	100	100	100	100
PSD Major Source ? (Y/N)	N	N	N	Y	N	N

As shown above, the facility is an existing PSD major source for at least one pollutant (CO).

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

PM10, SOx

The facility is a non-major source for PM10 and SOx and therefore BE = PE2 for these air contaminants.

CO

CO offsets are not required for this project as ambient air quality standards are not expected to be violated (see **Attachment V**). BE does not need to be evaluated.

NOx, VOC

S-525-2

BACT Guidelines for boilers have been rescinded and replaced by Rule 4320 requirements. The boiler is subject to the requirements of Category E Table 1 for NOx which is stated below.

Table 1 NOx Emission Limits			
Category	NOx Limit	Authority to Construct	Compliance Deadline
E. Units, from any Category, that were installed prior to January 1, 2009 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/year but < 30 billion Btu/year.	Standard Schedule 9 ppmv @ 3% O_2 or 0.011 lb/MMBtu	Twelve months before the next unit replacement but no later than January 1, 2013.	At the next unit replacement but no later than January 1, 2014

The unit operates in compliance as a Rule 4320 Emissions fee unit (Section 5.1.2) and is not in compliance with 9 ppmv NOx @ 3% O2. Therefore BE = HAE for NOx.

The facility provided fuel use for the baseline period years of 2013 and 2014 with an average NOx emissions factor of 0.033 lb/MMBtu. Note that the time period from January 1, 2015 until receipt of the application, September 8, 2015, was not considered representative on normal operation as operation of the boiler was curtailed. Therefore the baseline period did not include 2015.

	MMBtu/yr
2013	69,890 (exceeded 30,000 limit)
2014	9,594
Average	(30,000 + 9,594)/2 = 19,797 MMBtu/yr

Natural gas firing satisfies BACT for VOCs and therefore BE = PE1 for VOCs.

BE (lb/year)						
	NOx	SOx	PM_{10}	$PM_{2.5}$	CO	VOC
S-525-2	19,797 x 0.033 = 653 (HAE)	86 (PE1)	90 (PE1)	90 (PE1)	NA	600 (PE1)

S-525-51-0

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for SOx and PM10, this project does not constitute an SB 288 major modification for these air contaminants.

Since this facility is a major source for NOx, the project's PE2 is compared to the SB 288 Major Modification Thresholds in the following table in order to determine if the SB 288 Major Modification calculation is required.

SB 288 Major Modification Thresholds			
Pollutant	Project PE2 (lb/year)	Threshold (lb/year)	SB 288 Major Modification Calculation Required?
NO_x	9,725	50,000	No
SO_x	Na	80,000	No
PM_{10}	Na	30,000	No
VOC	Na	50,000	No

Since none of the SB 288 Major Modification Thresholds are surpassed with this project, this project does not constitute an SB 288 Major Modification.

8. 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.

Since this facility is not a major source for SOx, PM10, and VOCs, this project does not constitute a Federal Major Modification for these air contaminants.

The determination of Federal Major Modification is based on a two-step test. For the first step, only the emission *increases* are counted. Emission decreases may not cancel out the increases for this determination.

Step 1

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project. Applicant is proposing a new boiler with emissions increase of NOx, this project is a Federal Major Modification and no further analysis is required.

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

The project's combined total emission increases are compared to the Federal Major Modification Thresholds in the following table.

Federal Major Modification Thresholds for Emission Increases			
Pollutant	**Total Emissions Increases (lb/yr)**	**Thresholds (lb/yr)**	**Federal Major Modification?**
NO_x*	9725	0	Yes

*If there is any emission increases in NO_x or VOC, this project is a Federal Major Modification and no further analysis is required.

Since there is an increase in NO_x, this project constitutes a Federal Major Modification. Federal Offset quantities are calculated below.

Federal Offset Quantities:

The Federal offset quantity is only calculated only for the pollutants for which the project is a Federal Major Modification. The Federal offset quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the actual emissions (AE) during the baseline period for each emission unit times the applicable federal offset ratio. There are no special calculations performed for units covered by an SLC.

NOx **Federal Offset Ratio** **1.5**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
S-525-51	**0**	**9,725**	**9,725**
			0
			0
			0
		Net Emission Change (lb/year):	**9,725**
		Federal Offset Quantity: (NEC * 1.5)	**14,588**

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Sulfuric acid mist
- Hydrogen sulfide (H2S)
- Total reduced sulfur (inlcuding H2S)
- Reduced sulfur compounds

I. Project Location Relative to Class 1 Area

As demonstrated in the "PSD Major Source Determination" Section above, the facility was determined to be a existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

II. Project Emission Increase – Significance Determination

a. Evaluation of Calculated Post-project Potential to Emit for New or Modified Emissions Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the total potentials to emit from all new and modified units are below the applicable thresholds, no futher PSD analysis is needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)					
	NO2	SO2	CO	PM	PM10
Total PE from New and Modified Units	4.9	4.4	29.5	6.1	6.1

PSD Significant Emission Increase Thresholds	40	40	100	25	15
PSD Significant Emission Increase?	N	N	N	N	N

As demonstrated above, because the post-project total potentials to emit from all new and modified emission units are below the PSD significant emission increase thresholds, this project is not subject to the requirements of Rule 2410 and no further discussion is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. As the permit unit is new QNEC = PE2/4.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. 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 by the rule.

*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.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new boiler with a PE2 exceeding 2 lb/day for NOx, SOx, PM10, CO, and VOCs. BACT is triggered for NOx, SOx, PM10, CO, and VOCs.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does constitutes a Federal Major Modification for NOx emissions. Therefore, BACT is triggered for SB 288/Federal Major Modification purposes.

2. BACT Guideline

The NOx requirements of BACT Guideline 1.1.2 for this stationary source category is less stringent than Rule 4320 and has been rescinded. Compliance with the Rule 4320 NOx limit, which is 5 ppmv NOx @3% O2, has the effect of satisfying BACT for this class and category of source.

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see **Attachment VI**), BACT has been satisfied with the following:

Steady State

NOx: 5 ppmvd @ 3% O_2
SOx and PM10: Natural gas containing a sulfur content not exceeding 1.0 gr S/100 scf.
CO: 50 ppmvd @ 3% O_2 and natural gas fuel
VOC: Gaseous fuel

PEMS Training

Low NOx burner that achieves 20 ppmv NOx @ 3% O_2

Operator shall perform expeditious completion of PEMS Training activities not to exceed cumulative 30 days after commissioning of the boiler (i.e. installation of boiler, connection of gas pipelines, initiate fuel flow, installation of control systems, etc)

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	60,594	13,297	118,708	360,372	21,003
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets calculations required?	Yes	No	Yes	Yes	Yes

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X PM10, CO, and VOCs; therefore offset calculations will be required for this project.

However, Section 4.6.1 of Rule 2201 states that emissions offsets are not required for increases in CO in attainment areas provided the applicant demonstrates to the satisfaction of the APCO that the Ambient Air Quality (AAQ) Standards are not violated in the areas to be affected, such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of AAQ Standards. The District performed an AAQ Analysis and determined that this project will not result in or contribute to a violation of an AAQ Standard for CO (see **Attachment V**). Therefore, CO offsets are not required for this project.

Per Sections 4.7.1 and 4.7.3, the quantity of offsets in pounds per year for NO_X is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)

ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

Offsets Required (lb/year) = ([PE2 – BE]) x DOR

NOx

	PE2	PE1	BE = HAE	PE2 – BE (HAE)
S-525-51	9725	0	0	9725
S-525-2	0	1080	**653**	**-653**
Σ[PE2 – BE]				**9,072**

Offsets = Σ[PE2 – BE] x DOR
= x 1.5
= 9,072 x 1.5 lb/yr
= 13,608 lb/yr (3,402/qtr)

Therefore the appropriate quarterly emissions to be offset are as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total Annual
3,402	3,402	3,402	3,402	13,608

The applicant has stated that the facility plans to use ERC certificates listed in the table below to offset the increases in NOx emissions associated with this project.

ERC	1st QTR	2nd QTR	3rd QTR	4th QTR
OS requirement	3402	3402	3402	3402
S-3326-2	214	166	214	214
S-3625-2	6187 (618*)	473	646	602
C-1393-2	2070	2212	1904	1997
S-4710-2	364	328	400	391
N-1371-2	136	223	238	198
ERC Total	8971 (3402)	3402	3402	3402

*reserved

Therefore sufficient offsets have been provided for NOx and the above ERCs were reserved for the project.

VOCs

The quantity of offsets in pounds per year for VOCs is calculated as follows for sources with an SSPE1 less than the offset threshold levels is calculated as the increase in Stationary Source emissions above the offset trigger threshold (ROT) multiplied times the DOR or

[Σ[PE2 – BE] – (ROT – SSPE1)] x DOR

	PE2	PE1	BE	PE2 - BE
S-525-51	8769		0	8769
S-525-2	0		600	-600
Σ[PE2 – BE]				8,169
	ROT	SSPE1		ROT – SSPE1
	20,000	15,110		4,890

Note that the offsets requirement is calculated assuming DOR = 1.0. ERCs with reductions greater than 15 miles from the source (listed in the table below) are credited toward satisfying the offsets by dividing the quarterly amount 1.5.

Offsets (Increase above ROT x DOR) = [Σ[PE2 – BE] – (ROT – SSPE1)] x DOR
= (8,169 – 4,890) x 1.0
= 3,279 lb/yr (819.75 lb/qtr)

As shown in the calculation above, the quarterly amount of offsets required for this project, when evenly distributed to each quarter, results in fractional pounds of offsets being required each quarter. Since offsets are required to be withdrawn as whole pounds, the quarterly amounts of offsets need to be adjusted to ensure the quarterly values sum to the total annual amount of offsets required.

To adjust the quarterly amount of offsets required, the fractional amount of offsets required in each quarter will be summed and redistributed to each quarter based on the number of days in each quarter. The redistribution is based on the Quarter 1 having the fewest days and the Quarters 3 and 4 having the most days. The redistribution method is summarized in the following table:

Redistribution of Required Quarterly Offsets (where X is the annual amount of offsets, and X ÷ 4 = Y.z)				
Value of z	Quarter 1	Quarter 2	Quarter 3	Quarter 4
.0	Y	Y	Y	Y
.25	Y	Y	Y	Y+1

.5	Y	Y	Y+1	Y+1
.75	**Y**	**Y+1**	**Y+1**	**Y+1**

Therefore the appropriate quarterly emissions to be offset are as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total Annual
819	820	820	820	3,279

The applicant has stated that the facility plans to use ERC certificates listed in the table below to offset the increases in VOC emissions associated with this project.

ERC	1st QTR	2nd QTR	3rd QTR	4th QTR
OS requirement	819	820	820	820
S-3284-1	527	893	642	0
S-3625-1	57	0	59	55
C-1044-1	258/1.5 = 172	0	0/1.5 = 0	683/1.5 = 455
S-4714-1	184/1.5 = 123	0	202/1.5 = 135	196/1.5 = 131
N-1373-1	0	0	0	49/1.5 = 33
S-4658-1				247/1.5 = 165
ERC total	879	893	836	839

Therefore sufficient offsets have been provided for VOCs and the above ERCs were reserved for the project.

PM10

Per Sections 4.7.1 and 4.7.3, the quantity of offsets in pounds per year for PM10 is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = $(\Sigma[PE2 - BE] + ICCE) \times DOR$, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,

- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

Offsets Required (lb/year) = ([PE2 – BE]) x DOR

	PE2	PE1	BE	PE2 - BE
S-525-51	12,177		0	12,117
S-525-2	0		90	-90
Σ[PE2 – BE]				12,027 (3006.75/qtr)

Therefore the appropriate quarterly emissions to be offset (at DOR = 1.0) are as follows:

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total Annual
3,006	3,007	3,007	3,007	12,027

The applicant has stated that the facility plans to use ERC certificates listed in the following table to offset the increases in PM10 emissions associated with this project. Note that SOx ERCs may be used to offset PM10 ERCs at an interpollutant ratio of 1 to 1 according to District policy APR 14XX (Draft).

ERC	1st QTR	2nd QTR	3rd QTR	4th QTR
OS requirement	3,006	3,007	3,007	3,007
ERCs at DOR = 1.0				
S-3625-4	711	455	821	719
S-3625-5	5	5	6	5

Total ERCs at DOR = 1.0	**716**	**460**	**827**	**724**
ERCs at DOR = 1.5				
S-3352-5	158	835	687	274
C-1392-5	2273	1825	1572	2,075
N-1372-5	230	230	230	230
N-1375-5	15	21	22	19
S-4716-5	20	18	22	22
N-1374-4	508	686	481	556
S-4712-4	254	228	279	271
Total ERCs at DOR = 1.5	**3,458/1.5 = 2,305**	**3843/1.5 = 2,562**	**3,293/1.5 = 2,195**	**3,447/1.5 = 2,298**
ERC Total	716 + 2,305 = 3,021	460 + 2,562 = 3,022	827 + 2,195 = 3,022	2,298 + 724 = 3,022

Therefore sufficient offsets have been provided for PM10 and the above ERCs were reserved for the project.

Proposed Rule 2201 (offset) Conditions:

- {GC# 4447 - edited} Prior to operating equipment under this Authority to Construct, permittee shall surrender NOx emission reduction credits for the following quantity of emissions: 1st quarter – 3,402 lb, 2nd quarter – 3,402 lb, 3rd quarter – 3,402 lb, and fourth quarter – 3,402 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/08/16) for the ERC specified below. [District Rule 2201]

3. {GC# 4447 - edited} Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter – 819 lb, 2nd quarter – 820 lb, 3rd quarter – 820 lb, and fourth quarter – 820 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11) Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 2/08/16)~~.~~[District Rule 2201]

Prior to operating equipment under this Authority to Construct, permittee shall withdraw sufficient PM10 emission reduction credits to offset the following quantity of emission increases: 1st quarter – 3,006 lb, 2nd quarter – 3,007 lb, 3rd quarter – 3,007 lb, and fourth quarter – 3,007 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 2/08/16). SOx ERCs may be used to offset PM10 at an interpollutant offset ratio of 1:1. [District Rule 2201] Y

4. ERC Certificate Number S-3326-2, S-3625-2, ~~C-1393-2~~C-1393-2, S-4710-2S-4710-2, ~~N-1371-2~~N-1371-2, S-3284-1, S-3625-1, C-1044-1, S-4714-1S-4714-1, ~~N-1373-1~~N-1373-1, ~~S-4658-1~~S-4658-1, S-3625-4, S-3625-5, S-3352-5, ~~C-1392-5~~C-1392-5, ~~N-1372-5~~N-1372-5, ~~N-13~~75-5N-1375-5, S-4716-5N-4716-5, ~~N-13~~74-4N-1374-4, and S-4712-4N-4712-4 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Y

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project is a Federal Major Modification. Therefore, public noticing for SB 288 or Federal Major Modification purposes is required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NOx	26.6	100 lb/day	No
SOx	12.4	100 lb/day	No

PM_{10}	33.2	100 lb/day	No
CO	161.6	100 lb/day	Yes
VOC	24.0	100 lb/day	No

Therefore, public noticing for PE > 100 lb CO/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	55,096	60,594	20,000 lb/year	No
SO_X	8,860	13,297	54,750 lb/year	No
PM_{10}	109,387	118,708	29,200 lb/year	No
CO	303,182	360,372	200,000 lb/year	No
VOC	15,110	21,003	20,000 lb/year	Yes

As detailed above, the VOC thresholds was surpassed with this project; therefore public noticing is required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_X	60,594	55,096	5498	20,000 lb/year	No
SO_X	13,297	8,860	4,437	20,000 lb/year	No
PM_{10}	118,708	109,387	9321	20,000 lb/year	No
CO	360,372	303,182	57,190	20,000 lb/year	Yes
VOC	21,003	15,110	5,893	20,000 lb/year	No

As demonstrated above, the SSIPEs for CO were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V significant modification. Therefore, public noticing for Title V significant modifications is required for this project.

2. Public Notice Action

As discussed above, public noticing is required for this project. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

E. Compliance Assurance

1. Source Testing

Source testing will be required within 60 days of startup.

District Rules 4305, 4306 and 4320 require NOx and CO emission testing not less than once every 12 months. Gaseous fuel fired units demonstrating compliance on two consecutive compliance source tests may defer the following source test for up to thirty-six months. Source testing for Rules 4305, 4306, and 4320 also satisfies any source testing requirements for Rule 2201. No additional source testing is required.

2. Monitoring

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition(s) are listed on the permit to operate:

{3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070] Y

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis

Section 4.14 of this Rule requires that an ambient air quality analysis (AAQA) 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. Technical

Services Division performed modeling for criteria pollutants CO, NOx, SOx and PM10. The results are as follows:

Criteria Pollutant Modeling Results*

The results from the Criteria Pollutant Modeling are as follows:
Values are in μg/m^3

Pollutant	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
$PM_{2.5}$	X	X	X	Pass[2]	Pass[2]
PM_{10}	X	X	X	Pass[2]	Pass[2]

*Results were taken from the attached spreadsheet
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2020, using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b) (2).

As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, PM10, or SO_x. Refer to **Attachment V** of this document for the full AAQA report from Technical Services.

G. Compliance Certification

The compliance certification is required for any project, which constitutes a New Major Source or a Federal Major Modification.

Section 4.15.2 of this Rule requires 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. As discussed in Sections VIII-Rule 2201-C.1.a and VIII-Rule 2201-C.1.b, this project does constitute a Federal Major Modification, therefore this requirement is applicable. Included in **Attachment VII** is the Compliance Certification Statement.

H. Alternate Siting Analysis

Since the project will provide a new boiler to be used 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.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a "permit amendment that does not qualify as a minor permit modification or administrative amendment."

The project is Federal Major Modification and therefore is also a Title V Significant Modification. As discussed above, the facility has applied for a Certificate of Conformity (COC); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Included in **Attachment VII** is LOL's Title V Compliance Certification form. Continued compliance with this rule is expected.

Rule 4001 New Source Performance Standards

40 CFR 60 Subpart Db

This subpart applies to each steam generating unit capable of combusting more than 100 MMBtu/hr heat input of fuels, which is constructed, modified, or reconstructed after June 19, 1984. The provisions of 40 CFR 60 Subpart Db will apply to the proposed boiler because the boiler's maximum firing rate is 182 MMBtu/hr and will be constructed after June 19, 1984.

NOx

Emissions Limits

40 CFR 60.44b(a) includes the following NOx emissions limits for steam generating units combusting natural gas:

0.1 lb NOx/MMBtu for low heat release rate ($\leq$ 70,000 Btu/hr ft^2)
0.2 lb NOx/MMBtu for low heat release rate (> 70,000 Btu/hr ft^2)

This limit applies at all times including startups, shutdowns, and malfunctions pursuant to CFR 60.42b(h). Compliance with these standards is determined on a 30-day rolling average basis pursuant to 40 CFR 60.44b(i).

The proposed NOx emissions limit is 0.0061 lb/MMBtu and therefore the compliance is expected.

Source Testing

40 CFR 60.46b(e)(1) requires an initial performance test under 40 CFR 60.8 using a continuous (measurement) system for 30 consecutive steam generating unit operating days. Initial performance test is required within 60 days of achieving maximum

production rate but not later than 180 days after initial startup of the facility (when steam is used, see applicant email 12-21-15).

40 CFR 60.46b(e)(4) requires a 30 day follow-up performance test upon request using a continuous (measurement) system for 30 consecutive steam generating unit operating days. On days when performance tests are not required, NOx data shall be used to calculate 30-day rolling average emissions rates on a daily basis and used to prepare excess emissions reports but will not to be used to demonstrate compliance with the NOx emissions standards. A new 30-day rolling average emissions rate will be calculated on each steam generating operating day as the average of all hourly NOx emissions data for the preceding 30 steam generating operating days.

The ATC includes the following conditions ensuring compliance:

For the initial RATA, source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, 4306 and 4320, 40 CFR Subpart Db, 40 CFR Part 64] Y

Monitoring with CEMs (not proposed)

40 CFR 60.48b(b) discusses monitoring requirements with CEMs which has not been proposed.

Monitoring with PEMs (Proposed)

40 CFR 60.48b(g)(2) for natural gas combustion units with a heat input less than 250 MMBtu/hr the owner or operator of the affected facility must comply with the above requirements (for CEMs) or monitor the operating conditions and predict NOx emissions rates as specified in a plan submitted pursuant to 40 CFR 60.49b(c).

40 CFR 60.49b(c) affected facilities demonstrating compliance through 40 CFR 60.48b(g)(2) (paragraph above) shall submit a plan identifying operating conditions to be monitored and records maintained by 40 CFR 60.49(b)(g) within 360 days of the initial startup of the affected facility.

40 CFR 60.49b(c)(1) requires identification of specific operating parameters to be monitored and relationship to NOx emissions of such operating parameters such as degree of stage combustion, level of excess air, etc

40 CFR 60.49b(c)(2) requires inclusion of data and information used to obtain the relationship between the operating parameters and NOx emissions

40 CFR 60.49b(c)(3) requires identification of how these parameters will be monitored on an hourly basis, quality assurance to ensure that these operating parameters will be representative and accurate and type and format of records of these operating parameters

The ATC conditions related to PEMS plan, PEMS certification and PEMS QA/QC compliance ensure compliance with the above requirements.

The ATC includes the following condition:

Source shall submit a plan identifying operating conditions to be monitored with PEMS operation and records maintained (PEMS plan) within 360 days of the initial startup of the affected facility. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 60.49b(c)] Y

Records

40 CFR 60.49(b)(g)(1) Calendar date
40 CFR 60.49(b)(g)(2) Average hourly NOx emissions (for a given steam generator operating day)

40 CFR 60.49(b)(g)(3) 30-day average NOx emissions at the end of each steam generator operating day

40 CFR 60.49(b)(g)(4) Days in excess of NOx emissions limits

40 CFR 60.49(b)(g)(5) Days sufficient data was not obtained and corresponding corrective action

40 CFR 60.49(b)(g)(6) Times when data was excluded from average NOx emissions calculation

40 CFR 60.49(b)(g)(7) F factor use in calculation

40 CFR 60.49(b)(g)(8)(9)(10) Records specific to CEMs – not applicable

40 CFR 60.49(b)(h) requires submission of excess emissions reports,

40 CFR 60.49(b)(h)(4) excess emissions are any 30 day rolling average NOx emissions rate that exceed applicable emissions limits

The ATC includes the following condition to ensure compliance with the above requirement:

Permittee shall submit a PEMS written report for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter. Quarterly report shall include: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission *standard; applicable time and date of each period during which the PEMS was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [40 CFR Subpart Db, District Rule 1080, 8.0 and District Rule 2520, 9.6.1] Y*

SOx

Emissions Limit

40 CFR 60.42b(k)(1) includes the following emissions limit for facilities that commence construction after February 28, 2005 and that combust natural gas

0.2 lb SO_2/MMBtu

40CFR 60.42b(k)(2) exempts units firing gaseous fuels with a potential SO2 emissions rate of 0.32 lb SO2/MMBtu or less.

The proposed SOx emissions limit is 0.00285 lb SOx/MMBtu and therefore the new boiler is not subject to the Subpart Db SO_2 standard.

PM10 and Opacity

40 CFR 60.43b has no required PM10 emissions limit or opacity standard for natural gas combustion.

The ATC includes conditions ensuring compliance with the subpart.

Compliance Assurance Monitoring (CAM) - 40 CFR, Part 64

40 CFR Part 64 requires Compliance Assurance Monitoring (CAM) for units that meet the following three criteria:

1) the unit must have an emission limit for the pollutant;
2) the unit must have add-on controls for the pollutant; these are devices such as flue gas recirculation (FGR), baghouses, and catalytic oxidizers; and
3) the unit must have a pre-control potential to emit of greater than the major source thresholds.

The proposed boiler satisfies the above three requirements. 40 CFR Subpart Db monitoring requirements satisfy the CAM requirements.

CAM rule exemption:

40 CFR Subpart Db is post 11/15/90 and therefore its required monitoring satisfies CAM requirements.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). The unit is fired on natural gas only and visible emissions are not expected.

Therefore, compliance with the requirements of this rule is expected.

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 – Health Risk Analysis

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 perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (**Attachment V**, the prioritization score for the project was less than 1.0; however the facility's score was over 1.0. Therefore, a refined analysis was required and performed.

The acute and chronic hazard indices were below 1.0; and the cancer risk is less than 1 in a million. In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT). The following special condition is required:

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]

Rule 4201 Particulate Matter Concentration

Section 3.1 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.
F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM_{10} Emission Factor: 0.005 lb-PM_{10}/MMBtu

Percentage of PM as PM_{10} in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%

Excess Air Correction to F Factor = $\frac{20.9}{(20.9-3)} = 1.17$

$$GL = \left(\frac{0.0076\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0053\ grain/dscf < 0.1\ grain/dscf$$

Therefore, compliance with the requirements of this rule is expected.

Rule 4301 Fuel Burning Equipment

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

Section 5.0 gives the requirements of the rule.

A person shall not discharge into the atmosphere combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide at dry standard conditions.
A person shall not build, erect, install or expand any non-mobile fuel burning equipment unit unless the discharge into the atmosphere of contaminants will not and does not exceed any one or more of the following rates:

- 200 pound per hour of sulfur compounds, calculated as sulfur dioxide (SO_2)
- 140 pounds per hour of nitrogen oxides, calculated as nitrogen dioxide (NO_2)
- Ten pounds per hour of combustion contaminants as defined in Rule 1020 and derived from the fuel.

District Rule 4301 Limits			
Unit	**NO_2**	**Total PM**	**SO_2**
S-525-51-1 (lb/hr)	0.006 x 182 = 1.09	0.0076 x 182 = 1.38	0.00285 x 182 MMBtu/hr = 0.52
Rule Limit (lb/hr)	140	10	200

The particulate emissions from the boiler will not exceed 0.1 gr/dscf at 12% CO2 or 10 lb/hr. Further, the emissions of SOx and NOx will not exceed 200 lb/hr or 140 lb/hr, respectively.

Therefore, compliance with the requirements of this rule is expected.

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

The unit is natural gas-fired with a maximum heat input of 15.75 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4305.

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

The unit is natural gas-fired with a maximum heat input of 15.75 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

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

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

This rule limits NOx, CO, SO_2 and PM_{10} emissions from boilers, steam generators and process heaters rated greater than 5 MMBtu/hr. This rule also provides a compliance option of payment of fees in proportion to the actual amount of NOx emitted over the previous year.

The units in this project are all rated at greater than 5 MMBtu/hr heat input and are subject to this rule.

Section 5.1 NOx Emission Limits

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:

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

5.1.2 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

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

Section 5.2.1 states that on and after the indicated Compliance Deadline, units shall not be operated in a manner which exceeds the applicable NOx limit specified in Table 1 of this rule, shown below. On and after October 1, 2008, units shall not be operated in a manner to which exceeds a carbon dioxide (CO) emissions limit of 400 ppmv.

Category	Operated on gaseous fuel	
	NO_X Limit	CO Limit
Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or	400 ppmv
	b) Enhanced Schedule 5 ppmv or 0.0062lb/MMBtu	

The proposed NOx and CO emissions limits are 5 ppmv NOx @ 3% O_2 and 50 ppmv CO @ 3% O_2.

Therefore, compliance with the emissions limits of Section 5.2 of District Rule 4320 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.4, Particulate Matter Control Requirements

Section 5.4.1 of this rule requires the operator to comply with one of the following requirements:

1. Fire the boiler exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;
2. Limit fuel sulfur content to no more than five grains of total sulfur per one hundred (100) standard cubic feet;
3. Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight; or limit exhaust SO_2 to less than or equal to 9 ppmv corrected to 3.0% O_2;

The boiler is fired exclusively on PUC-regulated natural gas and therefore meets the particulate matter control requirements.

Section 5.6, Startup and Shutdown Provisions

Section 5.6 states that on and after the full compliance deadline in Section 5.0, the applicable emission limits of Sections 5.2 Table 1 and 5.5.2 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.6.1 through 5.6.5

The following startup/shutdown conditions will be added to the permit to ensure compliance with this section.

During startup or shutdown, the emissions control system shall be in operation, and emissions shall be minimized to the extent technically possible. [District Rules 2201 and 4320] Y

During initial PEMS training and testing period, the allowable duration of a start-up shall not exceed 12 hours per occurrence and the allowable duration of shutdown shall not exceed 9 hours per occurrence. [District Rules 2201 and 4320] Y

Except during initial PEMS training and testing period, startup and shutdown shall not exceed 2 hrs per occurrence. [District Rules 2201 and 4320] Y

Permittee shall record the daily startup and shutdown duration times of the boiler. [District Rules 2201, 4305, 4306, and 4320]Y

Section 5.7, Monitoring Provisions

Section 5.7.1 requires that permit units subject to District Rule 4320, Section 5.2 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NOx, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed the use of an approved PEMS in lieu of a CEMS to continuously monitor NOx, CO, and O_2 emissions from this boiler. The PEMS is subject to the same requirements as a CEMS, therefore the following condition will be added to the permit to ensure compliance with this section:

The owner or operator shall install, certify, maintain, operate and quality-assure a PEMS which continuously predicts and records the exhaust gas NOx, CO and O2 concentrations. Predictive emissions monitor(s) shall be capable of predicting emissions during normal operating conditions and during startups and shutdowns. PEMS results during startup and shutdown events shall be predicted using startup emission rates obtained from the initial performance source testing to determine compliance with emission limits contained in this permit. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Y

Section 5.7.6 outlines requirements for monitoring SOx emissions. For units that are complying with Section 5.4.1.1 or 5.4.1.2 of this Rule, the facility must provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit to Operate. The boiler in this project is complying with Section 5.4.1.1 by firing solely on PUC-Regulated natural gas. Therefore, the following requirement will be included on the permits to comply with the SOx emissions monitoring requirement:

Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320] Y

Section 5.8, Compliance Determination

Section 5.8.1 states the operator of any unit shall have the option of complying with either the applicable heat input, in lb/MMBtu, emission limits or the concentration, in ppmv, emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). The following condition will be added to the permit to ensure compliance with this section.

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 5.8.2 states that 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. Unless otherwise 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 will be added to the permit to ensure compliance with this section.

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. Unless otherwise 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 4320. [District Rules 4305, 4306, and 4320]

Section 5.8.3 states that Continuous Emissions Monitoring System (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits. Any 15-consecutive-minute block average CEMS measurement exceeding the applicable emission limits shall constitute a violation. The facility has proposed the use of an approved PEMS in lieu of a CEMS to continuously monitor emissions from this boiler. The PEMS is subject to the same requirement as a CEMS, therefore the following condition will be added to the permit to ensure compliance with this section:

PEMS emission measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits. [District Rules 4306 and 4320]

Section 5.8.4 applies to units using a portable analyzer as part of an approved Alternate Emissions Monitoring System. Since a portable analyzer is not used to monitor emissions from this boiler, the requirements of this section are not applicable.

Section 5.8.5 states 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 will be added to the permit to ensure compliance with this section.

For the proposed PEMS, yearly RATA and quarterly Relative Accuracy Audit (RAA) are required

PEMS relative accuracy (RA) testing must be conducted as specified in PS-16, Section 8.2 and must include 9 portable analyzer readings (RM, reference method) at each of low, medium, and high operating levels (3-level RA test). RA calculations using RM and PEMS data from the 3-level tests must be done using equations specified in PS-16, Section 12.2. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Y

PEMS RA must not exceed 10 percent if the PEMS measurements are greater than 100 ppm or 0.2 lb/MMBtu. The RA must not exceed 20 percent if the PEMS measurements are between 100 ppm (or 0.2 lb/MMBtu) and 10 ppm (or 0.05 lb/MMBtu). For measurements below 10 ppm, the absolute mean difference between the PEMS measurements and the RM measurements must not exceed 2 ppm. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Y

Permittee shall perform a relative accuracy audit (RAA) consisting of at least three 30-minute portable analyzer or RM (reference method) determinations each quarter a relative accuracy test audit (RATA) is not performed as specified in Section 9.3 of EPA Performance Specification 16. The average of the 3 portable analyzer (RM) determinations must not differ from the simultaneous PEMS average value by more than 10 percent of the analyzer or RM value for concentrations greater than 100 ppmv or 20% for concentrations between 100 and 20 ppmv or the test is failed. For measurements at 20 ppmv or less, this difference shall not exceed 2 ppmv for pollutant PEMS and 1% absolute for diluent PEMS. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Y

If a PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly (RATA) in the second year, the permittee may elect to perform a single mid-year RAA in the second year in place of the quarterly RAAs as specified in Section 9.3 of EPA Performance Specification 16. This option may be repeated, but only until the PEMS fails either a mid-year RAA or a yearly RATA. When such a failure occurs, you must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMS successfully passes both a year of quarterly RAAs and a subsequent RATA. [District

<u>*Section 6.1, Recordkeeping*</u>

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 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 non-compliance with the applicable requirements of this rule shall constitute a violation of this rule.

The following conditions will be added to the permit to ensure compliance with this requirement:

Permittee shall record the daily startup and shutdown duration times of the boiler. [District Rules 2201, 4305, 4306, and 4320] Y

All records related to the operation of the PEMS that are required by NSPS Subpart Db, 40 CFR Part 64 and EPA Performance Specification 16 must be kept in a form suitable for inspection for a period of at least five (5) years. [District Rule 1080] Y

All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070] Y

Section 6.1.2 requires that the operator of a unit subject to Section 5.5 shall record the amount of fuel use at least on a monthly basis. Since this boiler is not subject to the requirements listed in Section 5.5, Section 6.1.2 requirements are not applicable.

Section 6.1.3 requires that the operator of a unit subject to Section 5.5.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. This boiler is not subject to Sections 5.5.1 or 6.3.1. Therefore, the requirements of this section do not apply.

Section 6.1.4 requires that the operator of a unit with startup or shutdown provisions keep records of the duration of the startup or shutdowns. The following condition will be added to the permit to ensure compliance with this requirement:

Permittee shall record the daily startup and shutdown duration times of the boiler. [District Rules 2201, 4305, 4306, and 4320]

Section 6.1.5 requires that the operator of a unit fired on liquid fuel during PUC-quality natural gas curtailment periods record the sulfur content of the fuel, amount of fuel used, and duration of the natural gas curtailment period. This boiler is not fired on liquid fuels. Therefore, the requirements of this section do not apply.

Section 6.2, Test Methods

Section 6.2.1 states that fuel hhv shall be certified by third party fuel supplier or determined annually by ASTM D 1826-88 or D 1945-81 in conjunction with ASTM D 3588-89 for gaseous fuels.

Section 6.2.2 through 6.2.7 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2 or 19
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be added to the permit to ensure compliance with these requirements:

For the initial and subsequent RATA, 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] Y

For the initial and subsequent RATA, CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306 and 4320] Y

For the initial and subsequent RATA, stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4320] Y

For the initial and subsequent RATA, fuel sulfur content shall be determined using EPA Method 11 or Method 15. [District Rule 4320] Y

For the initial and subsequent RATA, source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 2201] Y

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.2 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the source test may be deferred for up to thirty-six months. As discussed above yearly RATA and quarterly RSS is required to ensure compliance with emissions limits.

Conclusion

Compliance with District Rule 4320 requirements is expected.

Rule 4801 Sulfur Compounds

A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2, on a dry basis averaged over 15 consecutive minutes. The boiler will combust natural gas containing no more than 1.0 gr S/100 scf. Compliance is expected.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

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 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; and
- 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.

<u>District is a Lead Agency & GHG emissions increases are from the combustion of fossil fuel other than jet fuels</u>

It is determined that no other agency has prepared 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 a policy, APR 2005, *Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency,* 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. Consistent with District Policy 2005, projects complying with an approved GHG emission reduction plan or GHG mitigation program, which avoids or substantially reduces GHG emissions within the geographic area in which the project is located, would be determined to have a less than significant individual and cumulative impact for GHG emission.

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, supported by a CEQA compliant environmental review document, aimed at 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. Further, the cap decreases over time, resulting in an overall decrease in GHG emissions.

Under District policy APR 2025, *CEQA Determinations of Significance for Projects Subject to ARB's GHG Cap-and-Trade Regulation*, the District finds that the Cap-and-Trade is a regulation plan approved by ARB, consistent with AB32 emission reduction targets, and supported by a CEQA compliant environmental review document. As such, consistent with District Policy 2005, projects complying project complying with Cap-and-Trade requirements are determined to have a less than significant individual and cumulative impact for GHG emissions. The GHG emissions increases associated with this project result from the combustion of fossil fuel(s), other than jet fuel, delivered from suppliers subject to the Cap-and-Trade regulation. Therefore, as discussed above, consistent with District Policies APR 2005 and APR 2025, the District concludes that the GHG emissions increases associated with this 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 § 15301 (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

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATC S-525-51-0 subject to the permit conditions on the attached draft ATC in **Attachment VIII**.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-525-51	3020-02-H	182 MMBtu/hr	$1080.00

Attachments

I. Current PTO S-525-2-8 and ATC S-525-51-0
II. Manufacturer's Information on Boiler
III. Information on PEMs
IV. Emissions Profiles
V. HRA and AAQA Modelling
VI. BACT Analysis
VII: Title V Compliance Certification Form and Statewide Compliance Statement
VIII: Draft ATC

ATTACHMENT I
Current PTO S-525-2-8 and ATC S-525-51-0

AUTHORITY TO CONSTRUCT

PERMIT NO: S-525-51-0 **ISSUANCE DATE:** 05/26/2016

LEGAL OWNER OR OPERATOR: LAND O' LAKES INC
MAILING ADDRESS: 400 SOUTH M ST
TULARE, CA 93274

LOCATION: 400 SOUTH M ST
TULARE, CA 93274

EQUIPMENT DESCRIPTION:
182 MMBTU/HR BABCOCK AND WILCOX COMPANY NATURAL GAS FIRED BOILER WITH COEN/TODD VARIFLAME LOW NOX BURNER (OR EQUIVALENT), CATASTAK SCR SYSTEM (OR EQUIVALENT), AND A PREDICTIVE EMISSION MONITORING SYSTEM (PEMS)

CONDITIONS

1. 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
2. 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
3. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOX emission reduction credits for the following quantity of emissions: 1st quarter - 3,402 lb, 2nd quarter - 3,402 lb, 3rd quarter - 3,402 lb, and fourth quarter - 3,402 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,229 lb, 2nd quarter - 1,230 lb, 3rd quarter - 1,230 lb, and fourth quarter - 1,230 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 4/21/11) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 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

Arnaud Marjollet, Director of Permit Services

5. Prior to operating equipment under this Authority to Construct, permittee shall withdraw sufficient PM10 emission reduction credits to offset the following quantity of emission increases: 1st quarter - 3,006 lb, 2nd quarter - 3,007 lb, 3rd quarter - 3,007 lb, and fourth quarter - 3,007 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 4/21/11). SOx ERCs may be used to offset PM10 at an interpollutant offset ratio of 1:1. [District Rule 2201] Federally Enforceable Through Title V Permit

6. ERC Certificate Number S-3326-2, S-3625-2, C-1059-2, N-1327-2, N-1329-2, S-3284-1, S-3625-1, C-1044-1, N-1326-1, N-1327-1, S-4396-1, S-3625-4, S-3625-5, S-3352-5, C-1304-5, N-1287-5, N-1326-4, N-1327-4, N-1326-5, and N-1327-5 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

7. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201] Federally Enforceable Through Title V Permit

8. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201] Federally Enforceable Through Title V Permit

9. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

10. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201] Federally Enforceable Through Title V Permit

11. Permit to Operate S-525-2-8 shall be cancelled upon implementation of ATC. [District Rule 2201] Federally Enforceable Through Title V Permit

12. 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]

13. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201] Federally Enforceable Through Title V Permit

14. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4201] Federally Enforceable Through Title V Permit

15. 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 60.49 b(d)(1)] Federally Enforceable Through Title V Permit

16. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

17. The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201] Federally Enforceable Through Title V Permit

18. Upon completion of initial commissioning of boiler (i.e. installation of boiler, connection of gas pipelines, initiate fuel flow, installation of control systems, etc) initial PEMS training and testing period shall not exceed 30 consecutive days. [District Rule 2201] Federally Enforceable Through Title V Permit

19. NOx emissions during Prediction Emissions Monitoring System (PEMS) training period shall not exceed 106.1 lb/day. Record of lb/day NOx and CO emissions during PEMs training shall also be kept. [District Rule 2201] Federally Enforceable Through Title V Permit

20. NOx emissions, including PEMS Training, shall not exceed 9725 lb/yr. [District Rule 2201]

21. NOx emissions shall not exceed 20 ppmv @ 3% O2 averaged over a 30-day PEMs initial training period. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

22. Permittee shall monitor and record the stack concentration of NOx continuously using CEMS during PEMs training period. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

23. Except during startup and shutdown and 30-day PEMs training period, emissions rates from the natural gas-fired unit shall not exceed any of the following limits: 5 ppmv NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 50 ppmv CO @ 3% O2 or 0.037 lb-CO/MMBtu, 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

24. NOx emissions limits shall not exceed 0.1 lb NOx/MMBtu for low heat release rate (< 70,000 Btu/hr ft2) and 0.2 lb NOx/MMBtu for low heat release rate (> 70,000 Btu/hr ft2) pursuant to 40 CFR 60.44b(a). This limit applies at all times including startups, shutdowns, and malfunctions pursuant to CFR 60.42b(h). Compliance with these limits is determined on a 24-hr average basis for the initial performance test and on a 3 hour average basis for subsequent performance tests pursuant to 40 CFR 60.44b(j). [40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

25. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 3% O2. [District Rule 4102] Federally Enforceable Through Title V Permit

26. PEMS or Continuous Emissions Monitoring System (CEMS) shall be certified within 60 days of completion of PEMs training period. [NSPS Subparts A and Subpart Db] Federally Enforceable Through Title V Permit

27. During startup or shutdown, the emissions control system shall be in operation, and emissions shall be minimized to the extent technically possible. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

28. During initial PEMS training and testing period, the allowable duration of a start-up shall not exceed 12 hours per occurrence and the allowable duration of shutdown shall not exceed 9 hours per occurrence. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

29. Except during initial PEMS training and testing period, startup and shutdown shall not exceed 2 hrs per occurrence. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

30. If CEMS is installed, unit shall comply with the emission monitoring requirements as specified in 40 CFR Part 60.48b. [District Rule 4001] Federally Enforceable Through Title V Permit

31. If PEMS is installed for NOx and CO, PEMS shall meet the requirements in 40 CFR 60, Performance Specifications 16 (PS-16) except as modified by this permit, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [40 CFR Subpart Db, 40 CFR Part 64, Rule 4320, and, District Rule 1080] Federally Enforceable Through Title V Permit

32. Permittee shall submit to the District for approval a plan (PEMS plan) that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b and Rule 4320. This plan shall be submitted to the District for approval at least 30 days prior to the start of the PEMS training period. [40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

33. At all times the PEMS must be operated in accordance with the requirements contained in EPA Performance Specification 16 for Predictive Emissions Monitoring Systems and Amendments to Testing and Monitoring Provisions. [District Rule 1080] Federally Enforceable Through Title V Permit

34. The owner or operator shall install, certify, maintain, operate and quality-assure a PEMS which continuously predicts and records the exhaust gas NOx, CO and O2 concentrations. Predictive emissions monitor(s) shall be capable of predicting emissions during normal operating conditions. PEMS results during startup and shutdown events shall be predicted using startup emission rates obtained from the initial performance source testing to determine compliance with emission limits contained in this permit. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

35. Details on the design of the PEMS (PEMS protocol) as specified in PS-16, Section 6.1 must be approved by the District prior to the start of the PEMS training period. This information must include number of input parameters, parameter operating envelope, source specific operating conditions affecting PEMS output, ambient conditions affecting PEMS operation, PEMS principal of operation including physical assumptions and mathematical manipulations supporting its operation, specific details on the testing to be performed for the PEMs training, data recorder scale, sensors to be used and sensor evaluation system, plan to detect and notify operator of parameter envelope exceedences, and recordkeeping. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

36. Initial Relative Accuracy Test Audit (RATA) must be conducted as specified in PS-16, Section 8.2 and must include 9 RM (Reference Method e.g. EPA Method 7c for NOx) tests at each of low, medium, and high operating levels. Relative accuracy (RA) calculations using RM and PEMS data from the 3-level tests must be done using equations specified in PS-16, Section 12.2. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

37. The absolute mean difference between the PEMS measurements and the reference method measurements shall not exceed 2 ppmv. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

38. Permittee shall perform a relative accuracy audit (RAA) consisting of at least three 30-minute portable analyzer or RM (reference method) determinations each quarter a relative accuracy test audit (RATA) is not performed as specified in Section 9.3 of EPA Performance Specification 16. The average of the 3 portable analyzer determinations must not differ from the simultaneous PEMS average value by more than 2 ppmv. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

39. If a PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly (RATA) in the second year, the permittee may elect to perform a single mid-year RAA in the second year in place of the quarterly RAAs as specified in Section 9.3 of EPA Performance Specification 16. This option may be repeated, but only until the PEMS fails either a mid-year RAA or a yearly RATA. When such a failure occurs, permittee must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMS successfully passes both a year of quarterly RAAs and a subsequent RATA. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

40. Statistical tests as specified PS-16, Section 8.3 including bias test, F-test, and correlation analysis must be used to evaluate paired RA and RM data for demonstration of continual compliance. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

41. The PEMS data is considered biased and must be adjusted if the arithmetic mean (d) is greater than the absolute value of the confidence coefficient (cc) in Equations 16.1 and 16.3 of EPA Performance Specification 16. In such cases, a bias factor must be used to correct the PEMS data. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

42. The calculated F-value (as specified in Section 13.3 of EPA Performance Specification 16) shall not exceed the critical F-value at the 95-percent confidence level for the PEMS to be acceptable. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

43. Operator shall perform a correlation analysis using the RA paired data from all operating levels combined to determine how well the RM and PEMS correlate. Use the equations in Section 12.3.3. The correlation is waived if the process cannot be varied to produce a concentration change sufficient for a successful correlation test because of its technical design. In such cases, should a subsequent RATA identify a variation in the RM measured values by more than 30 percent, the waiver will not apply, and a correlation analysis test must be performed at the next RATA. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64]

44. If PEMS fails to pass a quarterly RAA or yearly RATA test , or if changes are made that could result in a significant change in the emissions rate (e.g. process modification, new process operating modes, or changes to emission controls) the PEMS must be recertified by the earlier of 60 operating days or 180 calendar days after the failed RATA or after the change that has caused a significant change in emission rate as specified in PS-16, Section 8.5. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

45. Source shall maintain a Quality Control Plan (QA plan) including the components specified by PS-16, Section 9.0 to verify that the system is generating quality assured data after the initial PEMS certification test. QA plan shall include QA/QC summary of ongoing tests (listed in PS-16 Section 9.1 Table), daily sensor evaluation checks, quarterly RAAs, and yearly RATA. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

46. The operator shall monitor the ammonia injection rate during PEMS breakdowns to demonstrate NOx emission compliance. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

47. The PEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

48. PEMS emission measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits. [District Rules 4306 and 4320] Federally Enforceable Through Title V Permit

49. The PEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h), or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080] Federally Enforceable Through Title V Permit

50. The nitrogen oxide NOx emission rates measured by the PEMS shall be expressed in lb/million Btu or ppmv @ 3% O2. The 1-hour average emission rates shall be calculated using the data points required under Section 60.13(h)(2). The records shall also include a daily emission rate consisting of an averaged 24 hour rolling emission rate. [District Rule 2201; 40 CFR 60.48b (d) and 40 CFR Part 64] Federally Enforceable Through Title V Permit

51. The owner or operator shall maintain PEMS records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and emission measurements. [40 CFR 60.7(b), and District Rule 1080] Federally Enforceable Through Title V Permit

52. Permittee shall submit a PEMS written report for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter. Quarterly report shall include: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; applicable time and date of each period during which the PEMS was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [40 CFR Subpart Db, 40 CFR Part 64, District Rule 1080 and District Rule 2520] Federally Enforceable Through Title V Permit

53. 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

54. The initial PEMS training and testing and 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

55. 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

56. For the initial RATA, source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of completion of PEMS training period. [District Rules 2201, 4305, 4306 and 4320, 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

57. Source testing to measure NH3 slip from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 40 CFR Part 64] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

58. Source testing to measure NH3 slip from this unit shall be conducted at least once every twelve months or shall meet the alternate monitoring method established by mutual agreement with the District . After demonstrating compliance on two consecutive annual source tests, the unit shall be tested not less than once 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 twelve months. [District Rules 4102, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

59. For the initial and subsequent RATA, 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

60. For the initial and subsequent RATA, 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

61. For the initial and subsequent RATA, 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

62. For the initial and subsequent RATA, fuel sulfur content shall be determined using EPA Method 11 or Method 15. [District Rule 4320] Federally Enforceable Through Title V Permit

63. For the initial and subsequent RATA, source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 2201] Federally Enforceable Through Title V Permit

64. 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

65. For the initial and subsequent RATA, 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

66. Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320] Federally Enforceable Through Title V Permit

67. Permittee shall record the daily startup and shutdown duration times of the boiler. [District Rules 2201, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

68. All records related to the operation of the PEMS that are required by NSPS Subpart Db, 40 CFR Part 64 and EPA Performance Specification 16 must be kept in a form suitable for inspection for a period of at least five (5) years. [District Rule 1080] Federally Enforceable Through Title V Permit

69. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-525-2-8 **EXPIRATION DATE:** 10/31/2015

SECTION: 11 **TOWNSHIP:** 20S **RANGE:** 24E

EQUIPMENT DESCRIPTION:
71.7 MMBTU/HR BABCOCK AND WILCOX NATURAL GAS-FIRED BOILER WITH A TODD VARIFLAME LOW NOX BURNER AND FLUE GAS RECIRCULATION

PERMIT UNIT REQUIREMENTS

1. Pursuant to Rule 4320, beginning in 2010 the operator shall pay an annual emission fee to the District for NOx emissions from this unit for the previous calendar year. Payments are due by July 1 of each year. Payments shall continue annually until either the unit is permanently removed from service in the District or the operator demonstrates compliance with the applicable NOx emission limit listed in Rule 4320. [District Rule 4320]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
4. The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201] Federally Enforceable Through Title V Permit
5. 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. [District Rules 2201, 4305, and 4306] Federally Enforceable Through Title V Permit
6. Maximum annual heat input of the unit shall not exceed 30 billion Btu per calendar year. [District Rules 2201, 4305 and 4306] Federally Enforceable Through Title V Permit
7. Emissions rates from the natural gas-fired unit shall not exceed any of the following limits: 30 ppmv NOx @ 3% O2 or 0.036 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.003 lb-PM10/MMBtu, 81 ppmv CO @ 3% O2 or 0.06 lb-CO/MMBtu, or 0.02 lb-VOC/MMBtu. [District Rules 2201, 4305, and 4306] Federally Enforceable Through Title V Permit
8. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. 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 monitoring has been performed within the last month. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

9. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after 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 has occurred, subject to enforcement action. 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 4305 and 4306] Federally Enforceable Through Title V Permit
10. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission 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 (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
11. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
12. 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 and 4306] Federally Enforceable Through Title V Permit
13. Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (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 twelve (12) months. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
14. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
15. 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
16. 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 and 4306] Federally Enforceable Through Title V Permit
17. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
18. Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit
19. 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 and 4306] Federally Enforceable Through Title V Permit
20. 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

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

21. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rules 108.1 (Tulare), 407 (Tulare), and 408 (Tulare). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit
22. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following requirements: SJVUAPCD Rules 1081, 4201, 4301, 4304, 4305, and 4351. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit
23. The requirements of 40 CFR 72.6(b) and 40 CFR 60.40b do not apply to this source. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit
24. Records of monthly and annual heat input of the unit shall be maintained. [District Rules 2201, 4305, and 4306] Federally Enforceable Through Title V Permit
25. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306] Federally Enforceable Through Title V Permit
26. Permittee shall maintain records of annual heat input (MMBtu) for this unit on a calendar year basis. Such records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and Rule 4320]
27. On and after July 1, 2010, the permittee shall submit an analysis showing the fuel's sulfur content at least once every year. Valid purchase contracts, supplier certifications, tariff sheets, or transportation contacts may be used to satisfy this requirement, provided they establish the fuel parameters mentioned above. [District Rule 4320]

ATTACHMENT II
Manufacturer's Details

1.0 Overview

Nationwide Boiler understands that Land O'Lakes is working with Brighton Engineering to prepare a cost for a new 150,000 pph boiler at their Tulare plant in California. The new unit will operate at 520 psig saturated steam and have a 235-245°F feedwater temperature to the economizer. The unit will fire natural gas only and requires a NOx emission level of 5 ppm.

Using proven SCR (selective catalytic reduction) technology, this NOx level can easily be met without any compromises (i.e. compromises may include high burner FGR, sophisticated burner controls, reduced boiler turndown, etc.).

Our proposed solution for this project is to install a new Babcock & Wilcox D-Type water tube boiler rated for 600 psig pressure, an economizer with a vertical flow configuration, and a CataStak™ SCR also in a vertical flow configuration. The burner combustion air fan will be mounted above the burner as per specification requirements (see Figure 1 below). The boiler upper steam drum will be a nominal 54 inches diameter, far exceeding the specified requirement of 42". The drum internals are the cyclone separator type which reduces moisture content to 1 ppm (again exceeding the specified requirement of 3 ppm).

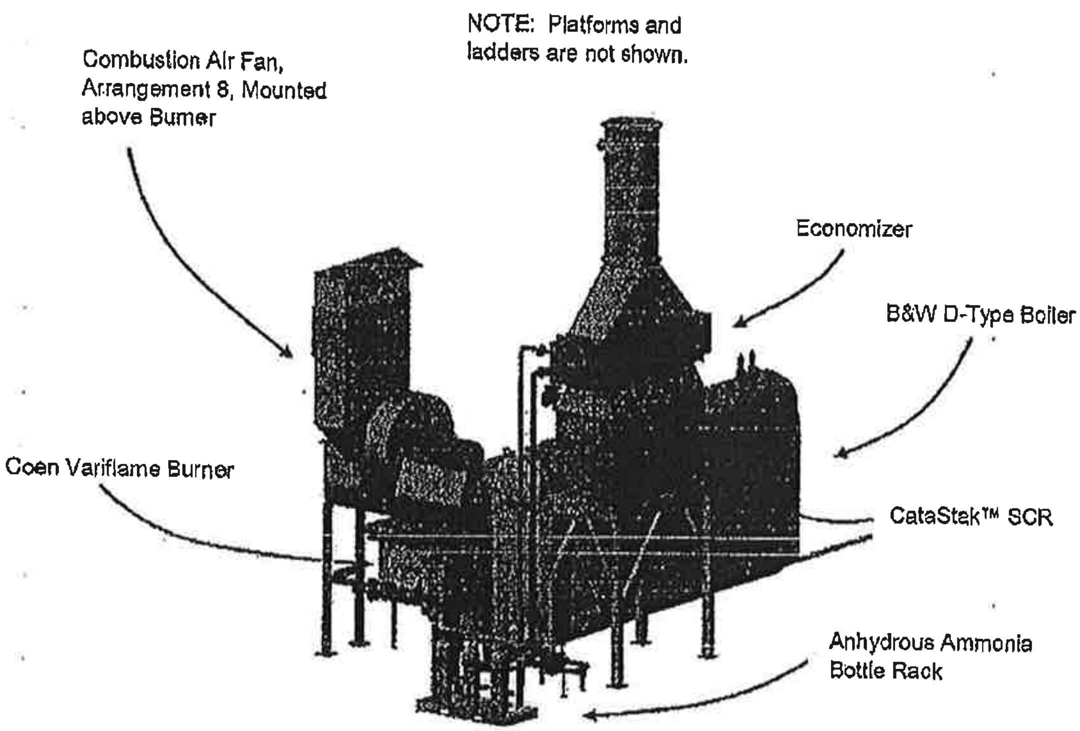

Figure 1: Conceptual drawing showing equipment layout.

2.0 Scope of Supply

The major components being provided are as follows:

2.1. Boiler

One (1) new Babcock & Wilcox D-type watertube package boiler, model FM120-97, 600 psig design pressure, operating at saturation temperature, capable of producing 150,000 lb/hr of steam at a pressure of 520 psig when supplied with feedwater temperature of 235-245°F and when being fired with natural gas.

The boiler is shop assembled with gas tight water cooled membrane wall construction for the furnace, baffles and outer walls. The boiler features a water cooled rear wall. The furnace is supplied with 2.5" tubes on 3.5" centers (versus competitor's 2" tubes on 4" centers) for maximum cooling and circulation in the highest heat area which promotes fast load response. The steam drum internals produce 1 ppm steam purity.

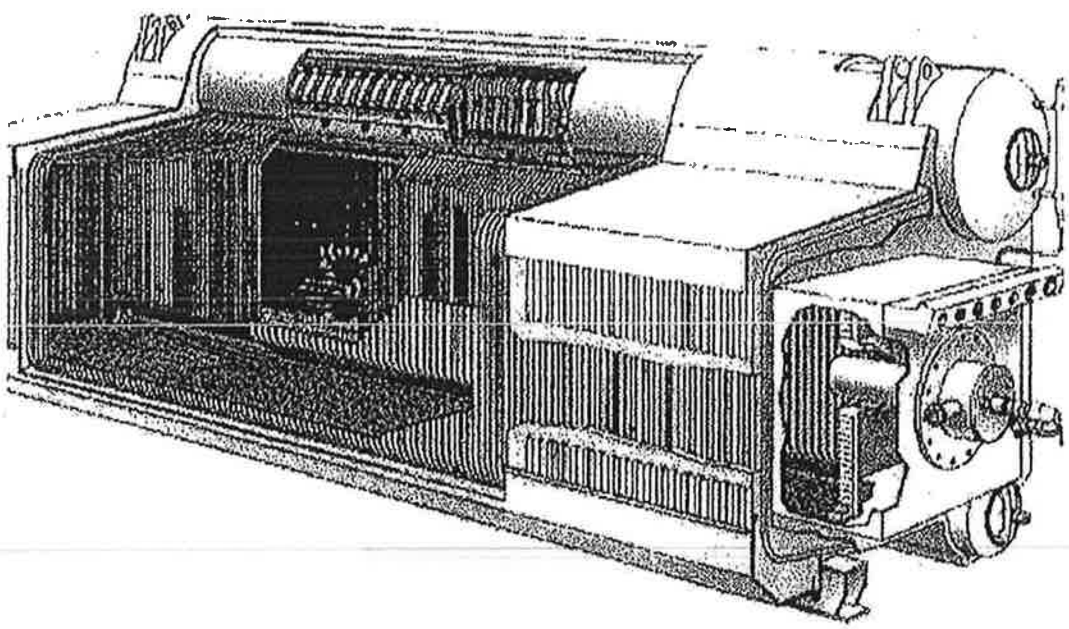

Figure 2: Schematic of Babcock & Wilcox D-type packaged boiler

Drums

Each Babcock & Wilcox type FM package boiler is supplied with one steam drum and one lower drum. The steam drums will be of adequate size to provide dry steam and allow for normal fluctuations in operating level; the lower drum will be sized to provide adequate circulation. Both drums will be fabricated out of 70,000 psi tensile strength material, generally SA516, Gr. 70, and of thickness as required by the ASME Boiler and Pressure Vessel Code in effect at the time of manufacture.

Each drum will be provided with two hinged manway covers to allow for ease of maintenance. The tube seats in both the steam drum and the lower drum are grooved. This provides for greater holding power when the tubes are rolled into the drums, thereby minimizing the potential for tube leaks.

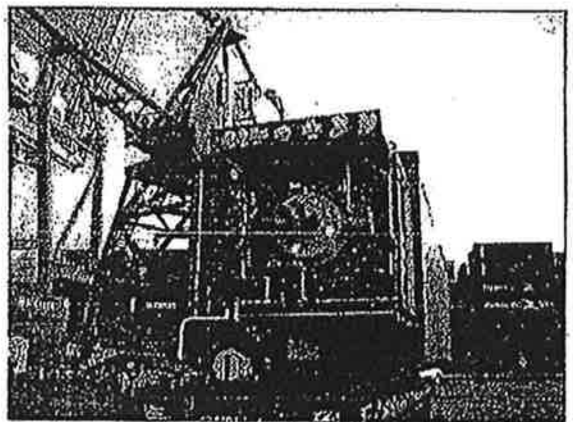

Figure 3: View of boiler front with upper steam drum and lower mud drum.

Drum Internals

Cyclone type drum internals will be provided to provide high steam purity and ensure positive circulation. Steam moisture will be reduced to 1 ppm using the cyclones and also using a corrugated-type secondary scrubber.

Tubes

The bank of boiler generating tubes will be arranged so that the combustion gases will flow horizontally across the tubes. This permits the most advantageous use of the convection heat absorption surfaces.

The boiler generating section will be comprised of 2" nominal diameter carbon steel tubes. This design assures that fast steaming through high rates of heat transfer from the hot gases occurs.

The division wall, which separates the generating section from the furnace, will be comprised of 2-1/2" nominal diameter tubes. The furnace wall described below also will be of 2-1/2" nominal diameter carbon steel tubes. The remaining water-cooled walls will be comprised of 2" nominal diameter, carbon steel tubes.

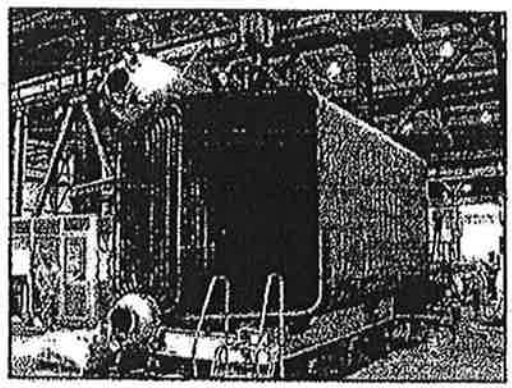

Figure 4: View of boiler tubes / generating bank

The division wall, which separates the generating section from the furnace, will be comprised of 2-1/2" nominal diameter tubes. The furnace wall described below also will be of 2-1/2" nominal diameter carbon steel tubes. The remaining water-cooled walls will be comprised of 2" nominal diameter, carbon steel tubes.

All tubes will comply with the requirements of the ASME Boiler and Pressure Vessel Code in effect at the time of manufacture.

B&W's furnace side, roof, floor, and division walls are fabricated using 2 ½" OD x 0.135" thick tubes. These tubes have a 1" solid membrane between the tubes creating 3 ½" center to center dimension. The competition uses a 2" OD tube that is 0.120" thick on low pressure applications or 0.135" for higher pressures. Each tube has a 1" fin on each side of it.

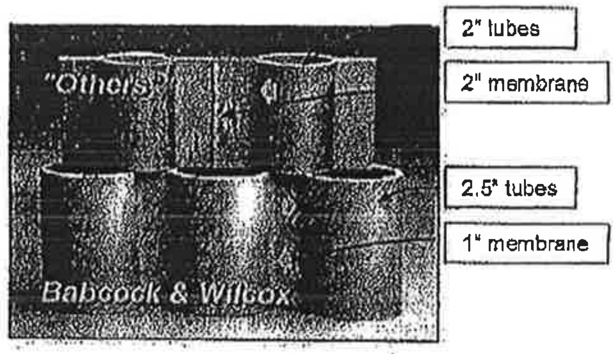

Figure 5: Babcock & Wilcox tube sizing compared to others

The adjacent fins between two (2) tubes are welded together creating 4" centers between each tube. The center point between two tubes is the hottest position in the furnace because it is the furthest location away from the direct water cooling effect of the tubes. Since this is the hottest spot, the competition's design has a weld located at a point that is most likely to fail. B&W's design minimizes the amount of indirect cooling in the furnace.

Walls and Insulation

The furnace walls will be comprised of water-cooling tubes, which form an integral part of the boiler circulation system. This design effectively cools the combustion gases, protecting the refractory and thereby minimizing maintenance. This design also takes advantage of the high rates of heat absorption that are possible in the radiant zone of the boiler.

Water-cooled tubes, comprising the furnace wall, the boiler sidewall, roof and floor, will be membrane construction. The membrane panels are constructed by utilizing large diameter tubes closed by small membrane bars welded to the tubes, thus achieving a completely cooled metal wall surface which, with its small membrane spacing, provides the best combination of heat transfer efficiency and maintenance accessibility. B&W's well known membrane wall setting design is furnished in place of an inner skin casing. The membrane tubes will be backed by a 4" layer of low-thermal conductivity glass blanket insulation compressed in one layer to 2-1/2". The boiler sidewall will be constructed out of 2" OD tubes on 4" centers separated by a membrane bar. It will also be backed by 4" of glass blanket insulation.

Rear Wall

The entire wall opposite the burner is 100% water-cooled and is known as the boiler and furnace rear wall. It is composed of studded tubes with the spaces between the tubes closed by flat studs welded to the tubes, thus achieving a completely sealed and cooled metal wall surface with its effectiveness in reducing maintenance. The studded tubes will be backed by 10-gauge carbon steel inner casing, 4" of 1.08-lb fiberglass T.I.W. blanket insulation compressed in one layer to 2", and 20 gauge box-ribbed, galvanized carbon steel lagging.

The additional heat transfer area between tubes is supplied by flat studs on each side of the tubes. Because the rear wall sees the larger amount of thermal expansion, the studded rear wall design allows each tube in the rear wall to grow independently of each other and remove the possibility of tear-out which can lead to rear wall hot spots. This wall is backed by a 10-ga. inner casing gas seal.

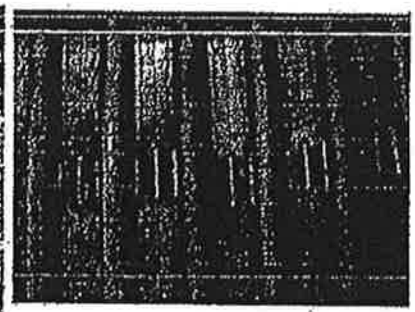

Figure 6: Views of boiler rear wall.

Front Wall

The wall in which the burner is located (known as the furnace front wall) will be constructed of 9" of high temperature insulating fire brick backed by 2" of high temperature insulating block, cased by 1/4" thick steel plate. The small voids in and around the brick will be filled with high temperature plastic refractory.

The absence of refractory baffles is a design feature to minimize maintenance. The wall separating the boiler from the furnace is called the baffle wall and will consist of a single row of membrane tubes for approximately four-fifths of its length. This will compel long flame travel, and assist in the mixing of the combustion gases before they enter the generating tube bank.

The furnace floor tubes shall be sloped sufficiently to eliminate the need for floor tile or firebrick. The upper drum shell above the tubes will be covered with 3" of 1.08 lb. fiberglass T.I.W. blanket insulation, compressed in one layer to 2".

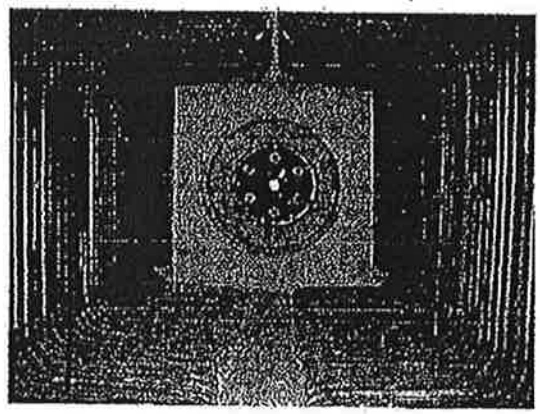

Figure 7: View of boiler front wall.

Casing

Each boiler will be completely enclosed in a pressure-tight casing, which is formed by the membrane wall construction. The outer casing over the whole boiler (except within the base frame) will be constructed of 20 gauge, weather-tight box-ribbed, galvanized carbon steel lagging. Prior to shipping, the entire boiler is primed and painted.

Boiler Trim and Components

Includes steam pressure gauge, water column, gauge glass, blowdown valves, safety valves, drum level transmitter and pneumatic feedwater control valve with three valve by-pass assembly (shipped loose).

2.2. Burner

Nationwide Boiler proposes to supply one (1) new Coen/Todd Combustion low NOx packaged burner which will fire natural gas.

Recognizing that combustion air is 94% of the mass flow through the burner, with fuel only being 6%, as part of the "system" solution for supplying a burner for optimum performance, Coen will provide air flow distribution studies of the windbox and upstream combustion air duct, using their in-house CFD modeling facilities. These model studies determine the size and location of straightening devices to be provided, in order to assure balanced air flow to the burner, and will result in reduced system draft losses, reduced stack emissions at lower excess oxygen levels, and greater boiler efficiency

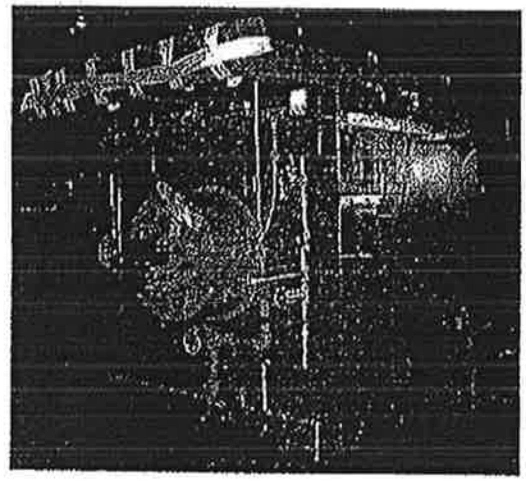

Figure 8: Packaged Coen Low NOx Burner

Windbox

One (1) windbox, non-insulated, will be fabricated of ASTM A-36 carbon steel plate, and complete with required structural framing; support legs, access door, lifting lugs, and straightening devices for balancing air flow distribution to the burner. The windbox will be provided with an inlet opening for connection to the combustion air duct. The windbox will be painted with manufacturer standard. The windbox will be seal welded to the boiler front plate

Register Assembly

One (1) Variflame burner, fabricated using standard stainless and mild steel components, complete with the following sub-assemblies, mounted in the windbox. The following is included:

- One (1) dual air register
- One (1) burner front hub assembly, complete with observation port, and flame scanner swivel mounts
- One swirling diffuser assembly
- One (1) gas burner assembly (fixed multiple poker)
- One (1) ignition assembly complete with gas-electric ignitor, high tension cable and connector and high energy transformer in a NEMA 4X SS enclosure
- One (1) throat former for installation of boiler front wall refractory at the burner opening

Pilot Gas Ignition Train

The ignitor gas pilot valve train will be shop mounted on the windbox and will include valves, piping specialties and instrumentation as specified below. All electrical components will be wired to a NEMA 4X SS terminal box. The ignitor gas pilot valve train will be fabricated using Schedule 80 ASTM A-106 Grade B seamless steel pipe and 3,000 lb. threaded fittings, and will be painted with manufacturer standard. The following will be provided:

- Supply manual shut-off valve, brass body, NPT
- Gas strainer with basket "Y" type, cast iron body, NPT
- Gas pressure regulating valve, cast iron body, NPT
- (2) Automatic safety shut-off valves, solenoid type, aluminum body, NPT (Asco)
- Automatic safety vent valve, solenoid type, aluminum body, NPT (Asco)
- Ignitor manual shut-off valve, brass body, NPT
- Ignitor pressure gauge, 2.5 in dial, with isolation valve
- Ignitor flexible hose, stainless steel body, NPT

Miscellaneous Instrumentation

The following miscellaneous field switches will be mounted on the windbox and wired to a NEMA 4X SS terminal box:

- One (1) combustion low air flow switch (Dwyer)
- One (1) purge low air flow switch (Dwyer)
- Two (2) boiler drum steam high pressure switches (Ashcroft)
- One (1) instrument air low pressure switch (Ashcroft)

Natural Gas Pipe Rack Assembly

The natural gas train components, as described below, to be factory piped, installed, and wired on a structural steel pipe rack assembly. All mechanical switches, limit switches and valves mounted on the pipe rack will be factory wired to terminal strips in a NEMA 4X enclosure.

Main Gas Train

Factory installed, wired and piped with Schedule 40 ASTM A-106 Grade B seamless steel pipe, with standard butt-weld fittings and 150 lb. flanges for nominal 3 inch diameter and larger lines, and Schedule 40 ASTM A-106 Grade B seamless steel pipe and 3,000 lb. threaded fittings for nominal 2-1/2 inch diameter and smaller lines. The natural gas train will be comprised of valves with aluminum, bronze, cast iron and steel bodies. Stainless steel tubing will be used in the installation of switches and gauges. The following will be provided:

- (1) Inlet Y strainer
- (1) Pressure regulator, Fisher 1098 EGR
- (1) 3051 SFA Rosemount Annubar flow meter with pressure and temperature compensation (per specs).
- (2) Pressure gauge with shutoff valve – installed in gauge panel (Ashcroft).
- (2) Gas flow control valve, pneumatically operated with Fisher DVC6200 positioner and limit switch.
- (2) Plug valve with wrench.
- High gas pressure switch (Ashcroft).
- Low gas pressure switch (Ashcroft).
- (2) Gas safety shutoff valves, pneumatic (24 vDC) – normally closed, with proof of closure switches.
- Gas vent manual valve.
- Vent valve, pneumatic (24 vDC) – normally open.
- "Y" Strainer.
- Pressure gauge with shutoff valve – installed in gauge panel (Ashcroft).

Flame Safety and Burner, Feedwater, SCR Controls

One (1) FSG and fully metered combustion control system -- with touch screen -- including all necessary flow elements, transmitters, O2 analyzer and programming. Boiler three element feedwater and the CataStak™ SCR ammonia flow rate are also controlled from this panel.

As per specifications, the combustion control system will be based around Allen Bradley's ControlLogix PLC, with a Wonderware InTouch 10.0 touch screen Operator Interface. The Operator Interface will be pre configured with the following screens: Loop Screen: (Plant Master Controller, Boiler Master Controller, Air Controller, Natural Gas Controller, SCR Controller, Oxygen Trim Controller, Drum Level Controller), alarm summary screens, alarm set point screen, Trended Display screens.

The burner management system will be based around Fireye's YB110/YZ300 BurnerLogiX Burner Management System. The BurnerLogiX Burner Management System will interface with the Operator Interface that will provide all the burner sequence/status information and "first out" annunciation of all burner fault conditions. The control panel itself will be Underwriters Laboratory Listed as an Industrial Control Panel (c-UL508). The control panels will have a full functional test prior to shipment. Our system will interface with your Plant's existing DCS system via Ethernet.

The following is included:

- Wall-Mounted enclosures of NEMA 4X 304SS construction with dimensions approximately 60" high X 36" wide X 12" deep.
- The enclosure will be finished in Sherwin-Williams Polane polyurethane acid and corrosion resistant enamel paint, the color to be "ANSI 61 Gray". Interior surfaces to be finished in white enamel paint.

Mounted within the panel on a removable subbase and wired to numbered terminal blocks will be:

Allen-Bradley ControlLogix PLC programmed for Combustion Control consisting of:

- (1) 1756-L71 Processor w/2MB Memory
- (1) 1756-EN2T Ethernet Communications Module
- (1) 1756-A13 13-slot rack
- (1) 1756-PA75 120VAC power supply
- (2) 1756-IA16 16-point 120vac Input Module
- (1) 1756-OW16I 16-point relay output module
- (2) 1756-IF8 8-point voltage/current analog Input module
- (1) 1756-IRT8I 8-point isolated RTD/Thermocouple Input module
- (1) 1756-OF8I 8-point 4-20ma output module

- Fireye YB110 microprocessor based flame safeguard control with YP100 program module and UV self-checking flame detector amplifier.
- Fireye YZ300 expanded annunciator module.
- Regulated loop power supply, 24vdc/3a.
- Isalatrol IC115 active tracking 120vac power filter, 15a.
- Ethernet 5-port switch.
- Modbus/Ethernet gateway.
- (4) Warrick Level relays.

The following components will be flush mounted on each panel and will be identified by black lamacoid nameplates with white lettering:

- Advantech Model IPPC-9151-BTO, loaded with Wonderware InTouch 10.6 Runtime Software Operator Interface Terminal, with 15" XGA color display, touch screen display, NEMA 4X construction, 2.25mb flash memory card, with the following configured screens:
    - Boiler Status Graphical Overview Screen

  - Burner Sequence and Running Status Screens
  - SCR Operations Screen
  - Alarm Summary Screen for all system faults.
  - Control Loop Screen for: Boiler Master Controller, Air Controller, Natural Gas Controller, SCR Controller, Oxygen Trim Controller, Drum Level Controller.
  - Trended Process Variables Screen for: Boiler Steam Flow, Boiler Feedwater Flow, Boiler Water Level, Boiler Steam Pressure, Natural Gas Flow, Fuel Oil Flow, and Flue Gas Oxygen.
  - Engineer Password protected screens for: 10-pt curve for fuel/air ratio (2), 10-pt curve for oxygen trim (2), 10-pt linearizers for each damper and valve output, (2), trended-loop tuning for each loop, transmitter scaling
- BURNER On-Off selector switch.
- LIMITS COMPLETE indicating light (green).
- MAIN FUEL ON indicating light (green).
- BURNER FAILURE/RESET indicating pushbutton (red).
- Alarm Horn with silence pushbutton.
- Hoffman T150116G100 NEMA 4 air conditioner, 115vac, 800 btu/hr.

The system will be completely factory wired in accordance with NEC standards. Prior to delivery, the system will be pre-tested to assure proper and safe operation. All wiring between terminal blocks and components will be numbered and encased in plastic wiring troughs with removable covers. Labels will be used to identify all panel-mounted devices in accordance with the electrical schematic.

2.3. Combustion Air Fan

The combustion air fan will be mounted above the burner as per specification requirement and will include:

- Air foil, centrifugal type fan in a downblast configuration, Arrangement 8, 1800 RPM
- Drive coupling, shaft guard
- Air inlet box with inlet silencer and pitot tube for measuring air flow
- Rosemount 3051 DP transmitter and 3 valve manifold (for air flow measurement)
- 250 HP TEFC motor, high efficiency
- Variable inlet vane damper with pneumatic positioner
- Parallel bladed outlet damper with pneumatic positioner
- Allen Bradley PowerFlex VFD, Nema 1 (to be mounted in motor control center)

2.4. CataStak™ SCR

The Nationwide CataStak™ SCR NOx reduction system is designed for low cost and maximum stand-alone operation with minimum operator intervention. It includes all critical components to enable startup, control and shutdown.

The CataStak SCR system is comprised of the following primary components:

- One (1) Structural steel catalyst housing
- One (1) Lot catalyst modules
- One (1) Ammonia Injection Grid (AIG)
- One (1) Ammonia Flow Control Unit (AFCU)
- One (1) Lot, misc. instrumentation

<u>SCR DeNOx Catalyst</u>

The DeNOx catalyst features:

- High NOx removal activity
- Low pressure drop

- Low SO2 oxidation rate
- Excellent durability
- Low temperature performance

Typical DeNOx catalysts are based on a corrugated, fiber reinforced titanium dioxide (TiO_2) carrier. The carrier is impregnated with the active components: vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels.
The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The high and well-defined porosity is the key to:

- A high NOx removal level with minimum ammonia slip
- A low activity towards SO2 oxidation, minimizing the risk of fouling downstream equipment
- A high poison resistance ensuring a long and stable service life
- A substantially lower weight than for conventional plate or extruded catalysts, allowing a fast response to changes in operation

Structural Steel Housings

The DeNOx catalyst will be supplied in structural steel housing with framework and gasket material as required. The housing will include custom inlet and outlet transitions with access doors. The housing and inlet transitions will be insulated and lagged.

Ammonia Flow Control Unit (AFCU)

Ammonia flow control components will be skid mounted in a compact space-saving arrangement where all operating devices are within close proximity of each other and within easy access for the operator.

Ammonia flow rate will be precisely controlled based on a feed forward signal from a boiler gas flow transmitter and the predetermined uncontrolled NOx emissions. Control of ammonia flow vs. NOx is obtained throughout the entire turndown range to minimum NOx and ammonia slip. Ammonia vapor from the Ammonia Storage Skid will be diluted with air before entering the Ammonia Injection Grid (AIG) located upstream of the SCR Catalyst. The following components are included:

- Ammonia valve train, stainless steel, including: Control valve (flow is pressure and temperature compensated for precise control), shutoff valves, pressure regulator, high and low pressure switches, all pre-piped and wired on skid.
- Dilution air blower with air inlet filter and air pressure switch.
- Ammonia / dilution air mixer.
- The ammonia flow control will be controlled by the Allen Bradley PLC panel provided with the burner.

Ammonia Injection Grid

The Ammonia Injection Grid (AIG) consists of a header feeding a group of injection lances distributed across the flue gas duct. The AIG provides uniform injection of the ammonia/air mixture over the duct cross section.

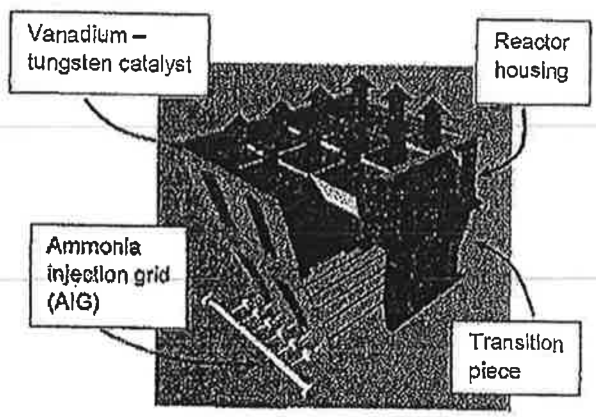

Figure 8: Sketch of sample CataStak™ Unit

ATTACHMENT III
Information on PEMs

LISTEN.
THINK.
SOLVE.

LAND O'LAKES, INC.

Software CEM®

APRIL 20, 2015
PROPOSAL: WPA04202015JM

FIXED PRICE PROPOSAL

Present to: Doug Findley
Land O'Lakes
400 South M Street
Tulare, CA

Office of Issue: Rockwell Automation, Inc.
9500 Arboretum Boulevard, Suite 400
Austin, Texas 78759-5638
214-909-4234
ATTN : Joseph Miller

Allen-Bradley • Rockwell Software **Rockwell Automation**

Table of Contents

1 Executive Summary

Rockwell Automation (Rockwell) is pleased to submit to Land O'Lakes this proposal for our industry leading Software CEM® solution to be installed on (1) Boiler at the Tulare Plant, at Tulare, CA. Our solution provides accurate emissions monitoring through both first principle and empirical mathematical modeling.

We look forward to working with the Land O'Lakes to develop and design accurate environmental solutions to meet their needs and ensure compliance.

1.1 Scope Statement

Land O'Lakes has requested a proposal from Rockwell Automation to provide a reliable and cost effective emissions monitoring system solution to be installed on (1) Boiler (s) at the Tulare Plant . This proposal includes the Pavilion8 software and engineering services to develop and commission a Software CEM® system that will meet certain emissions monitoring requirements for State of California. Rockwell Automation's Software CEM® solution provides the following benefits when compared to traditional hardware CEMs and versus other PEMS solutions:

- Rockwell's Software CEM® is more accurate and reliable than hardware CEMs (reaching 3-5% relative accuracy)
- The maintenance costs of Rockwell's Software CEM® is 60 – 90% less than a hardware CEM
- Experience since 1993, including more than one thousand stack years and RATAs passed
- Software CEM®' has a 100% passing rate of RATA certification (accuracy) tests
- Sensor Validation and Reconstruction
- Fast deployment of Software CEM®– typically in 30 to 45 days with our record being 9 days
- Web interface allowing remote access to system status and operations
- NERC CIP compliant
- Optimization add-on option

2 Proposed Solution

Rockwell Automation will provide the software and engineering services to implement and deliver our Software CEM® solution to meet State of California regulatory and environmental needs as required by the San Joaquin Air Quality Management District.

2.1 Basis for Proposal

This proposal is based on information received prior to the proposal date and assumptions made based on the available information and instructions provided by Land O'Lakes. Rockwell Automation reserves the right to revise the quotation if new information becomes available.

2.2 Scope of Work

Rockwell Automation has divided the Scope of Work into the following sections:

- Rockwell Automation's Responsibilities
- Customer Responsibilities
- Miscellaneous Information
- Assumptions
- Special Considerations

These sections define the scope and content of the solution proposed.

A. Rockwell Automation Scope of Work

Provide Pavilion8 Software Continuous Emissions Monitor (Pavilion8 Software CEM) application components as described below for the following source(s), emissions and fuels

Source	Emissions	Fuels
1 Boiler	NO_X and O_2,	Natural Gas,
Additional Work	**Version**	**Server Type**
Upgrade Existing Boiler	Pavilion 8	Virtual Server for both units

All descriptions below pertain only to unit(s) listed above.

The finished system(s) will be fully compliant with US EPA's Performance Specification 16 for PEMS as of the effective date of this Work Assignment.

a. Responsibilities

The scope of Rockwell Automation's (Rockwell's) responsibility is the following:

i. Kick-off meeting participation to discuss the project plan and design details including the design of experiments for required data collection;
ii. Design, development and installation of *Software CEM* application(s) necessary to calculate emissions from the combustion unit(s) while operating within the ranges tested during the performance of the set of designed experiments; and
iii. Training of customer personnel on the use and support of installed Software CEM application(s).

b. Deliverables

Deliverables to be provided by Rockwell are as follows:

i. A Functional Specification to be delivered prior to application development describing the site-specific functionality;
ii. Rockwell software for the Software CEM application(s) per the Master License Agreement;
iii. Configurations for the Software CEM applications;

iv. Upgrade existing Pavilion Software CEMs application:
v. Install existing and new Pavilion Software CEMs on a virtual server;
vi. As-Built documentation of *Software CEM* application(s); and
vii. A Site Guide describing site-specific administrative and end-user procedures.

c. Application Features and Capabilities

The finished application will have the following features and capabilities:

i. Data reconciliation – model inputs will be subjected to gross error checking (availability, sanity limits and flatline detection.) Any emissions model input that fails a gross error check will be substituted with a value calculated using Rockwell's sensor validation and reconstruction methodology;
ii. Data Views – Rockwell's standard *Software CEM* diagnostic views will be provided;
iii. Output – per-minute emissions calculations and statuses will be written to Customer's DCS or process data historian; and

d. Specific Exclusions

Items not included in Rockwell's scope of work include:

i. Items not described above or those that are included in the Customer's Scope of Supply below;
ii. Changes to the scope of work, responsibilities, deliverables or timeframes;
iii. Application re-certification events following initial certification;
iv. Travel and living costs related to execution of this project;
v. Stand-by time such as time spent on-site waiting for completion of Customer or third-party project deliverables (e.g. correction of construction, installation or wiring errors) or other delays beyond Rockwell's control or not in Rockwell's Scope of Work;
vi. Custom software development of any kind; and
vii. Exclusivity arrangements of any kind. Rockwell retains the rights to use the engineering and applications knowledge developed on this project in other plants.

e. Acceptance

The Rockwell Scope of Work shall be considered complete when the following conditions exist:

i. Licensed Rockwell software for the Software CEM application(s) has been installed;
ii. Configuration of the Software CEM application(s) has been completed and set to run on an automatic basis;
iii. The Software CEM application(s) has successfully passed the initial certification tests (e.g. the Relative Accuracy Test Audit for NOX and O2 PEM System) as described in US EPA's Performance Specification 16 for PEMS or the Customer has been unable to allow these tests to take place for thirty (30) days since completion of Software CEM application(s) configuration; and
iv. All Rockwell documentation deliverables been provided.

2. Customer Scope of Work

a. Responsibilities

The scope of Customer's responsibility is the following:

i. Subcontract and management of environmental testing services required for model development and initial certification for the Software CEMs application(s);
ii. Procurement of the application computer (where the virtual machine will reside) and operating system; procurement and installation of 3rd party software;
iii. Communication as needed with the regulatory agencies responsible for PEMS approval;
iv. Timely review of the Functional Specification, set(s) of designed experiments and the delivered *Software CEM* application(s) and the communication of any concerns to Rockwell;
v. Assistance in the determination of the units' operating envelopes prior to the development of the plant testing plan.
vi. Management and configuration of non-Rockwell supplied control system(s), data historian(s), relational database(s) and other process data systems;
vii. Maintenance of the combustion unit(s) and instrumentation and the communication of specific changes in the operating condition, measurement methods, tag names or instrument calibration methods and/or ranges prior to data collection for validation, tuning or certification;
viii. Achieving normal, sustained operating conditions and during data collection for development, validation and/or certification of the *Software CEM* application(s);
ix. Process operating changes per designed experiments for data collection and certification testing of the *Software CEM* application(s) in a timely manner;
x. Coordination of all on-site testing with operations personnel (e.g. work permits, operator instruction, etc.);
xi. Participation in the installation and initial certification of the *Software CEM* application(s);
xii. Maintenance of the combustion equipment after data collection for application development;
xiii. Day-to-day monitoring and support of the delivered application(s) after commissioning—including the review and response to alarms, the communication of tag name changes and ensuring the combustion units are maintained within the tested operating regions;
xiv. Performance of all systems management activities such as application computer installation, account creation, network configuration, integration with system devices and non-Rockwell supplied applications, routine backups, system software upgrades and other systems maintenance activities; and
xv. Any required Compliance testing, except as noted under Rockwell responsibilities, above.

b. Deliverables

Deliverables to be provided by Customer are as follows:

i. A Project Manager with overall responsibility for this project;
ii. Information on the in-scope combustion unit(s), instrumentation and control;
iii. Control system-specific interface hardware and software;
iv. Safe and adequate environmental sampling locations and power supplies for third-party environmental testing personnel and equipment;
v. Provision of remote access to the application computer(s) for application development and support activities;

vi. Documentation needed to comply with management-of-change and/or ISO 9000 requirements; and

vii. Training of operators and/or the preparation of operator guides. Subcontract and management of environmental testing services required for model development and initial certification for the Software CEMs application(s);

viii. Procurement of the application computer (where the virtual machine will reside) and operating system; procurement and installation of 3rd party software;

3. Miscellaneous

Changes to the Project may be requested at any time by either the Customer or the Rockwell Management Team. Since a change could affect the scope, price, schedule or other terms of the engagement, any proposed changes to the project's scope, tasks or deliverables will be evaluated by the Project Management Team to determine if a change order is required. Rockwell's change management methodology shall be used to manage change and scope.

4. Assumptions

The following assumptions were used in the development of this scope of work. Deviations from these assumptions could result in increased costs, schedule delays and/or change orders.

1. LOL complies with Section 2, LOL Scope;
2. Once the project has begun, tasks will be performed in a continuous sequence without significant or frequent delays in project execution;
3. The Rockwell team will be provided a workspace at the LOL site and access to the computer(s) as needed to commission the application software;
4. LOL has OPC interface installed and working on their Wonderware data historian process control system that can be used by the Pavilion8 Software CEM application without additional cost to the project;
5. The Pavilion8 web console will be the operator interface to the application. Only trivial amounts of additional services will be expended designing or supporting additional operator interface functionality in LOL's Wonderware data historian process control system;
6. All manipulated variables are adjustable through the LOL Wonderware data historian process control system in a continuous fashion (i.e. using a form of PID and not ON/OFF or "bang-bang control".) If any manipulated variables are not automated (e.g. hand valves), Rockwell will be informed and a joint decision will be made regarding LOL automation of these variables or a change to the Pavilion8 Software CEM application scope. In the event that any manipulated variable controller malfunctions and cannot be repaired or replaced within thirty (30) days from identification or the issue or failure, the variable will be removed from Rockwell's Scope;
7. A process test plan can be agreed and performed by LOL operators that moves the set points of manipulated variables and holds the process at each state long enough that their steady-state impact on controlled/dependent variables can be identified;
8. No major equipment, process or fuel changes will be made during the project that will impact acceptance testing of the application;
9. Documentation deliverables will be provided in the English language;
10. Rockwell will be permitted to communicate general information regarding this scope and resulting application performance such as percentage of improvements in production and quality, project timeframe and payback time estimates and screen captures demonstrating controller actions (but which protect Customer's confidential information.)
12. In-scope emissions sources burn only fuels listed above and those fuels are of constant composition. If variable composition fuels are burned, LOL performs online fuel analysis and can manipulate the composition during the data collection on demand and hold that composition for a duration sufficient to

repeatable measure the steady-state impact of fuel composition changes on emissions (approximately 30 minutes.) If fuel composition is variable, not measured online and cannot be controlled, none of the constituents of the fuel that amount to more than 0.5 mole percent of the fuel on average vary over time by more than 5% of their mean values;

13. No nitrogen-containing compounds are burned by the emissions source(s) in sufficient quantities to affect measured NO_X emissions;
14. All burners and other combustion-related equipment are in repeatable, good working order and variables known to affect emissions such as de-icing, flue gas recirculation, steam or water injection, hearth-to-wall ratios or manual air register positions are in fixed settings or instrumented such that their state or setting can be measured electronically and manipulated on demand so the steady-state impact of changes on emissions can be measured;
15. Each emissions source has a dedicated stack with accessible sample ports positioned correctly for representative flue gas sampling;
16. Any stack testing performed for application development, validation or certification will be performed with consistent equipment and methodology and shall comply with the requirements outlined in the *Pavilion8 Software CEM Emissions Sampling and Analysis Procedures* version 3 or later, including compliance with applicable EPA methods, protocol one reference gases, 8-hour (or more frequent) calibration frequencies, redundant systems, heated sample lines, effective sample water removal, etc.
17. Rockwell will be provided time to perform an application accuracy validation and fine tuning prior to starting the initial demonstration of compliance tests (e.g. RATA);
18. Ongoing application re-certification events following initial demonstration of compliance are not included in this scope;
19. Ambient atmospheric absolute humidity or pressure, temperature and relative humidity is measured and available in the LOL control system;
20. If carbon monoxide (CO) is an in-scope emission, the application will be configured to calculate normal emissions observed during data collection. High or no measurable CO events driven by abnormal fuels, airflows or physical configurations not tested during data collection will not be calculated;
21. If sulfur dioxide (SO_2) is an in-scope emission, the application will be configured to calculate SO_2 from the amount of sulfur in the fuel and fuel flow data. Sulfur in fuel data is available from online analysis or entered manually by LOL operators. Sulfur in fuel will be assumed 100% converted to SO_2.
22. If the range of observed ambient conditions during data collection is so small that the impact of absolute humidity—and to a lesser extent temperature—on NO_X formation cannot be characterized, a second data collection may be required. This is not common. Any additional testing expenses and Rockwell services required to support a second mobilization and/or additional demonstration of compliance (certification) events are outside the scope of this work assignment and may be performed in a subsequent application support agreement;
23. LOL is capable of maintaining key process parameters with high correlations to emissions at constant conditions for a sufficient period of time to demonstrate steady state correlations to in-scope emissions. As a guide, the US EPA RATA procedure specifies that the Pavilion8 Software CEM be compared to a reference analyzer using the averages of nine of twelve 21-minute runs. Therefore, it should be possible to maintain key model inputs at relatively steady conditions over at least 189 minutes to conduct a US EPA approved RATA;
24. Predicted NO_X (ppm) and O_2 (%) along with all available *Software CEM* status information will be written back to the Customer-supplied data server (DCS or historian) in real-time via an OPC-DA or OPC-HDA virtual server to be procured and installed by Customer; and

5. Special Considerations

a. **Regarding Unpredictability of Weather and Timing of Data Collection** - As described above, changes to the project may occur that could affect price, schedule etc. One possible change scenario involves ambient weather conditions. Ambient temperature and absolute humidity impact NOx formation. Depending upon combustion unit design, the *Software CEM* application(s) will likely need to take these variables into account. For this to occur, the initial data collection must include variation of ambient humidity, and to a lesser extent temperature.

For combustion units whose data collection occurs during spring or fall, this typically occurs naturally due to the frequent change in weather during those times and the normal duration of the DoE data collection period. However, it is possible data collection may occur when ambient weather conditions do not vary significantly. In many designs, this requires abbreviating the initial DoE (minimal replication of experimental data points) and returning to perform a second round of data collection some weeks or months later when the nominal weather conditions have changed enough to provide the required variation in ambient humidity and temperature.

Since this elapsed time period may not occur within the *Software CEM* testing requirements mandated by environmental regulatory authority, it may be necessary to build and certify the *Software CEM* application(s) using the limited data and then go back at a later date to gather additional data and revise the application(s) to reach the desired level of accuracy and robustness. Any additional third-party testing expenses and Rockwell services required to support a second mobilization and recertification are outside the scope of this work assignment.

B. Remote Access Obligations

Ownership

1. Land O'Lakes must provide a point of contact for resolution of remote access issues.
2. Land O'Lakes will retain complete control of the remote access and take all commercially reasonable measures to protect the Land O'Lakes system from unauthorized access. ROCKWELL WILL NOT HAVE ANY LIABILITY FOR THE ACTS OR OMISSIONS OF THIRD PARTIES IN CONNECTION WITH THE PROVISION OF REMOTE ACCESS SERVICES.
3. Land O'Lakes will be responsible for all reasonable technical, administrative and financial obligations with respect to communication costs incurred in providing Remote Access Services.

Functional capabilities

1. Rockwell can view and control the computer desktop, including use of the Windows "Start" button and viewing programs running locally on the computer.
2. While working via remote access, Rockwell has an account with privileges sufficient to perform application engineering activities.
3. The remote access link allows bi-directional file transfer capability for ASCII and binary files.
4. The remote access link allows a remote user to browse to all Rockwell Pavilion8 web console pages from the local system desktop.
5. For sites with Rockwell applications on multiple computers, the remote access host allows the remote user to tunnel (extend) remote access from the remote access host through the Land O'Lakes network to application computers through the use of VNC, Remote Desktop or other remote access software provided by Land O' Lakes.

Performance

1. The time required to log in to local desktop must be less than five (5) minutes.

2. The time required to open a 100 KB file in Notepad, modify the last line, and save the modified file must be less than one (1) minute.
3. The time required to browse to Rockwell application logon web page must be less than fifteen (15) seconds.
4. The time required to transfer a 100 KB file in either direction must be less than one (1) minute.

Availability

1. If assistance is required from Land O'Lakes to gain access (e.g., activate a modem), it must be possible to contact the technician and establish connectivity during normal Land O'Lakes business hours within one (1) hour.
2. Remote access may continue beyond normal business hours. Remote access will be terminated by Rockwell, and if requested, notification of termination will be made upon disconnect.
3. Under normal circumstances, connections must last at least one (1) hour without disruption.

Scope of Use

As a condition to the use of Land O'Lakes remote access system, Rockwell agrees:

1. To comply with Land O'Lakes remote access guidelines provided to Rockwell in writing.
2. To only use Land O'Lakes remote access to provide the Rockwell scope.
3. To not seek information on, obtain copies of, or modify files, tapes, passwords or any type of data belonging to other Land O'Lakes users unless specifically authorized to do so.
4. To not use Land O'Lakes systems to intentionally develop or execute programs that could harass other users, infiltrate Land O'Lakes systems, or damage or alter Land O'Lakes systems.

3 Commercial Offer

3.1 Investment

This fixed price proposal is based on Rockwell Automation's understanding of the supplied bid materials and requested scope.

TABLE – Investment	
One (1) *Software CEM®* system (software & services) designed to comply with EPA and State of California Department of Air Quality requirements.	$160,000.00
One (1) Existing Boiler Software CEMs system Upgrade	Included
Virtual Machine (does not include host server)	Included

This is Rockwell Automation's estimate of project costs based upon our understanding of the functional requirements and what is required to implement Software CEM®. All prices are in U.S. dollars, applicable taxes are not included. All written quotations automatically expire unless accepted within thirty (30) days from the date quoted.

The price quote above does not include travel and living expenses for the Rockwell engineer who will configure and install the Software CEM®. An estimate of travel and living expenses is provided in section 3.1.1 of this proposal.

This proposal is based upon Rockwell Standard terms and conditions included in Section 4 of this Proposal.

3.2 Travel & Living Expenses

Travel and living expenses for the Rockwell engineers who will be implementing the Software CEM project are not included in the price quote for the project above. Travel and living expenses typically include round trip airfare to and from the customer site, hotel, rental car and meals.

The customer will be invoiced for travel and living expenses at Rockwell's cost plus 10%.

Travel and Living Estimate – Two (2) Trips $5,500.00

3.3 Purchase Order Instructions

Please direct all purchase order correspondence to the attention of:

Attn: Joseph Miller
Rockwell Automation, Inc.
9500 Arboretum Blvd, Suite 400
Austin, TX 78759
Phone: 414-526-9972
Fax: 512-438-1560
Jdmiller1@ra.rockwell.com

Please specifically references acceptance of Rockwell Automation Proposal No. WPA04202015JDM and its terms in your purchase orders.

3.4 Invoicing Schedule

Upon Acceptance of a purchase order, the invoicing milestones will be as follows:

- 30% Upon Receipt of Order
- 30% Upon Delivery of Functional Specification
- 30% Upon Completion of Commissioning
- 10% Upon RATA Compliance and Customer Acceptance

All invoices are NET 30 days and in U.S. dollars.

3.5 Milestone Acceptance

Rockwell will document completion of each milestone referenced in Section 3.4 above by providing Land O'Lakes with a form of Milestone Acceptance Document to be executed by Land O'Lakes Project Manager shall accept (by execution) or reject the Milestone Acceptance on or before the seventh (7th) business day following receipt of the Milestone Acceptance Document. Failure to either accept or reject the Milestone Acceptance Document by the seventh (7th) business day shall be deemed acceptance as if executed.

Completion of Commissioning

Commissioning of the application(s) is complete when the following conditions exist:

1. All hardware, software and application deliverables have been installed on the application computer(s) and all aspects of application data integration (I/O) have been tested and verified (i.e. the application is/applications are installed);
2. The application has/applications have operated for two (2) days without a documented fault (i.e. the application is/applications are commissioned); and
3. Rockwell Automation provides written notice to Land O'Lakes that the application is/applications are complete and ready for acceptance testing.

Acceptance

The application(s) will be accepted when all Rockwell deliverables have been provided and the Pavilion8 Software CEM application has/applications have successfully passed the initial demonstration of compliance tests (e.g. the Relative Accuracy Test Audit for NOX and O2) as described in US EPA's Performance Specification 16 for PEMS. If Land O'Lakes determines that specific site acceptance test(s) cannot be completed successfully, Land O'Lakes will notify the Rockwell project manager in writing upon completion of the site acceptance test. Upon receiving notification, Rockwell will rectify the issue and make arrangements for the specific site acceptance test(s) to be performed again.

If site acceptance testing is delayed by Land O'Lakes, through no fault of Rockwell, the start of the site acceptance tests may be delayed up to thirty (30) with written notice by Land O'Lakes after completion of commissioning. If at the end of this delay, the site acceptance tests still cannot be performed, the application shall be considered accepted.

4 Term and Conditions

1. General. This Agreement ("Agreement") is the entire agreement of the parties, superseding any previous agreements and understandings, whether oral or written. It exclusively will govern the provision of Work, licensing, and support by Rockwell Automation of the Software furnished under this Agreement. No addition or modification to this Agreement will be binding unless mutually agreed to in writing. Each party rejects any other terms and conditions that are in addition to or not consistent with this Agreement that may be proposed by the other party or that appear or are referenced in Customer's purchase order or other requisition or in Rockwell Automation's invoice.

2. Definitions.

2.1. "Configuration/Application Code" means software developed by Rockwell Automation specifically for the Customer, such as for example, code developed under a Software Implementation Services Agreement.

2.2. "Customer" means, Land O'Lakes for itself and on behalf of its affiliates, with a with a principle place of business at Tulare Plant , Lancing, California

2.3. "Customer Support Contacts" has the meaning ascribed thereto in Section 13.2.

2.4. "Designated Location" means the site and application owned and/or operated by Customer where the Software is located.

2.5. "Error" shall mean any error, problem or defect resulting from either of: (i) an incorrect functioning of the Software or (ii) an incorrect or incomplete statement in the end user documentation, if such an error, problem, or defect renders the Software inoperable or causes incorrect functions to occur when the Software is used.

2.6. "High Risk Activities" has the meaning ascribed thereto in Section 27.

2.7. "Internal use" or "internally use" means use by or for Customer at a Designated Location on a Rockwell Automation approved platform.

2.8. "License Term" has the meaning ascribed thereto in Section 15.1.

2.9. "Major Release" shall mean a release for which the version number has a different most significant digit than the previous release of such Software (i.e. version 5.0 is a major release while version 4.2 is not a major release.)

2.10. "Object Code" means computer programming code in the form not readily perceivable by humans and suitable for machine execution without the intervening steps of interpretation or compilation.

2.11. "Release" shall mean Software that contains significant feature additions and enhancements and requires that the Software be re-compiled into a complete new disc or compilation for download. Releases shall be identified with a product name and a sequential release number.

2.12. "Rockwell Automation" means Rockwell Automation, Inc., a Delaware Corporation, for itself and on behalf of its affiliates, having a principal place of business at 1201 S. 2nd Street, Milwaukee, WI 53204.

2.13. "Samples" has the meaning ascribed thereto in Section 7.

2.14. "Scripting Code" means computer programming code interpreted by another program at runtime rather than compiled, such as HTML.

2.15. "Software" means the Object Code version of the software (including any Configuration/Application Code, if any), and related formal documentation provided by Rockwell Automation.

2.16. "Source Code" means computer programming code in human readable form that is not suitable for machine execution without the intervening steps of interpretation or compilation.

2.17. "Support Fees" has the meaning ascribed thereto in Section 14.1.

2.18. "Support Services" has the meaning ascribed thereto in Section 13.1.

2.19. "Support Term" has the meaning ascribed thereto in Section 15.3.

2.20. "Warranty Period" has the meaning ascribed thereto in Section 16.1.

2.21. "Version" shall mean modification or fixes to a specific Release of the Software or Documentation that correct Errors, support new Releases of operating systems, support new input/output (I/O) devices, or provide other incidental or minor enhancements, performance improvements and corrections. Versions shall be identified with a product name and a sequential version number.

3. **Limited License.** Subject to Customer's compliance with the terms and conditions of this Agreement and timely payment of any applicable License Fee(s) herein, Rockwell Automation grants and agrees to grant to Customer, and Customer accepts, a limited, nontransferable, non-exclusive license: (i) to internally use the Software in Object Code form only in accordance with the License Type, and (ii) to internally use and internally modify, in conjunction with its use of the Software under sub-section (i) above, any Scripting Code, algorithm or documentation developed by Rockwell Automation pursuant to a services agreement, and only in accordance with any written instructions provided by Rockwell Automation.

4. **License Restrictions.** Customer will not (i) sublicense, rent, sell, lease, assign or transfer any rights, grant a security interest in, or provide commercial hosting of the Software or attempt to do any of the foregoing, (ii) separate component parts of the Software for independent use, (iii) reverse engineer, disassemble, de-link, or create derivative works of the Software, (iv) move the Software or any part thereof from the Designated Location without the prior written consent of Rockwell Automation, or (v) make a copy of the Software, except for archival back-up purposes.

5. **No Implied License.** Nothing contained in this Agreement shall be construed to confer either directly or by implication, estoppel, or otherwise, any license or other right not expressly provided hereunder. Without limiting the generality of the foregoing, no license or other right is granted by this Agreement: (i) under any patents; (ii) to any copyrights, software or firmware, designs, trade secrets, or other non-public information or technology except to the extent specifically identified on Exhibit A; and, (iii) to any trade dress, trademark, service mark, registration, graphics or other depictions, name or trade name.

6. **Programs Not Licensed.** For purposes of administrative convenience, Rockwell Automation may include program code which Customer is not licensed to use along with the copy of the Software distributed to Customer. Customer agrees that it will only use those portions of the Software code to which it holds a license from Rockwell Automation.

6.1. If the Software requires a software activation process, such as FactoryTalk® Activation, Customer agrees to follow such activation process.

6.2. If the Software contains a software license tool or feature which manages the installation and use of the Software, Customer agrees to use such tool or feature as instructed.

6.3. The Software may contain third party software which requires notices and/or additional terms and conditions. Such required third party notices and/or additional terms and conditions are identified in the help or about screens and license.txt or readme text files of the Software and are made a part of and incorporated by reference into this Agreement.

7. **Samples.** The Software may include samples, plug-ins, UI components and/or reports that are provided as an accommodation to Customer ("Samples"). These Samples are intended to be used for example purposes or to provide additional complimentary features. The Samples may be contained in the Software, documentation (electronic or printed) or downloaded from a Rockwell Automation website. Rockwell Automation and its third party licensors make no representations or warranties regarding Customer's use of the Samples and related documentation. All such Samples are provided "AS IS" and any and all warranties and support obligations do not apply.

8. **Price.** Customer will pay Rockwell Automation the Fee(s) (exclusive of applicable taxes and duties unless otherwise specified) within net thirty (30) days from date of invoice. Interest charges will be added to overdue invoices at the rate of 1.5% per month, subject to any limit imposed by applicable law.

9. **Delivery.** Rockwell Automation will deliver to Customer one (1) copy of the Software in Object Code and one (1) copy of Software documentation, in a manner regularly furnished to its general customer base. Ex Works Rockwell Automation's plant or warehouse (per current Incoterms) or as otherwise specified in the Scope of Work (Delivery). In all cases, title transfers to Customer upon the earlier of Rockwell Automation's delivery to Customer or receipt by the first carrier for transport to Customer, except that title to all intellectual property rights associated with the Work remains with Rockwell Automation or its suppliers and licensors.

10. **Acceptance.**

10.1. Acceptance occurs: (i) on the date the Work conforms to acceptance criteria in the Scope of Work or is otherwise beneficially used by Customer, but in no event later than ninety (90) days following Delivery; or (ii) if otherwise unspecified, upon Delivery.

10.2. **Interim Approvals.** Any Rockwell Automation submittal or deliverable requiring Customer approval pursuant to the Scope of Work will be deemed accepted if formal Customer approval, written or as otherwise required, is not received by Rockwell Automation within two calendar weeks after the date submitted.

11. **Changes.**

11.1. Any change resulting from any of the following circumstances is subject to equitable adjustments to price, scheduling, and other affected terms and conditions:

11.1.1. Customer requested order changes, including those affecting the identity, scope, and delivery of the Work;

11.1.2. Concealed or otherwise unknown physical conditions differing materially from those indicated or anticipated in the Scope of Work or that otherwise differ materially from those ordinarily found under similar circumstances;

11.1.3. Any delays caused by Customer, its employees, affiliates, other contractors to Customer, or any other party within Customer's reasonable control;

11.1.4. Any emergency endangering persons or property. In such circumstances, Rockwell Automation may act at its discretion to prevent damage, injury, or loss.

11.2. All changes, except actions necessitated by emergencies as provided in Section 11.1.4 above, will be effected by a written change order signed by both parties or otherwise definitively authorized by both parties. Rockwell Automation will not begin work on a change until such change order is properly authorized. All claims relating to a change must be made within a reasonable time after the occurrence giving rise to the claim. If the parties cannot agree on a change in pricing or schedule, it will be resolved pursuant to Section 39, Disputes.

12. Audit. Rockwell Automation may audit Customer's use of the Software for compliance with this Agreement, upon reasonable notice. In the event that such audit reveals any use of the Software by Customer other than in full compliance with the terms of this Agreement, Customer shall reimburse Rockwell Automation for all reasonable expenses related to such audit in addition to any other costs or liabilities Rockwell Automation may incur as a result of such non-compliance.

13. **Support Services.**

13.1. Subject to Customer's compliance with the terms and conditions of this Agreement and timely payment of any applicable Support Fee(s) herein, Rockwell Automation will provide Customer "Support Services" during the Support Term. "Support Services" means Rockwell Automation will (i) use commercially reasonable efforts to promptly correct Errors, (ii) provide technical support and assistance for the Software during Rockwell Automation's normal business hours (excluding Rockwell Automation holidays for standard support) with respect to the Software, including a telephone support number, facsimile number and/or email address available solely to customers that have entered into support contracts, and (iii) provide to Customer such bug fixes, new releases, updates, product extensions and enhancements as are generally provided to Rockwell Automation's customers who are active on Support Services. Rockwell Automation reserves the right to discontinue Support Services on any Software product on twelve (12) months notice, and to discontinue Support Services for any Major Release six (6) months after the second subsequent Major Release.

13.2. Customer shall appoint two designated support contacts ("Customer Support Contacts") and shall identify its Customer Support Contacts by providing written notice to Rockwell Automation containing at a minimum the names, telephone number, email address and mailing address of each Customer Support Contact.

14. **Support Fees and Renewals.**

14.1. "Support Fees" are set forth in the proposal, exclusive of applicable taxes and duties unless otherwise specified. Support Fees shall be payable net thirty (30) days from date of invoice.

14.2. Rockwell Automation may increase the Support Fees for any Support Term after the initial Support Term. Rockwell Automation shall invoice Customer upon execution of this Agreement and thereafter annually at least ninety (90) days prior to the expiration of the then-current Support Term.

14.3. If Support Services should terminate and Customer is in good standing under this Agreement, Customer may reinstate Support Services on payment of the cumulative Support Fees applicable for the period during which Support Services lapsed, plus Support Fees for the then-current Support Term.

15. **Default, Delays, Term, and Termination.**

15.1. The term of the license provided by Rockwell Automation to Customer in Section 3 shall be perpetual (except as may be limited by the License Type or otherwise as set forth in the proposal) unless terminated by either party as set forth herein. Any and all License Fee(s) and Support Fee(s) paid to Rockwell Automation prior to termination shall be non-refundable.

15.2. Customer may terminate its license at any time by written notice to Rockwell Automation provided that such termination shall not relieve Customer from its responsibility to make any payments due under the Agreement.

15.3. The "Support Term" shall be one (1) year beginning on the date of this Agreement and shall automatically renew for successive one (1) year Support Term(s) unless Customer provides notice to Rockwell Automation of its intent not to renew Support Services not less than sixty (60) days prior to the end of the then-current Support Term.

15.4. Rockwell Automation reserves the right to terminate this Agreement and all license rights granted pursuant to this Agreement immediately by written notice to Customer if Customer: (i) fails to timely make any payments due under this Agreement, (ii) breaches any of the restrictions on use, assignment, or discloses Rockwell Automation Confidential Information, or (iii) becomes insolvent or unable to pay its debts as they become due; or (iv) if voluntary or involuntary bankruptcy proceedings are instituted by Customer or against Customer, or a receiver or assignee for the benefit of creditors is appointed for Customer.

15.5. The termination of this Agreement will not prejudice the right of Rockwell Automation to recover any fees due it at the time of termination. Customer agrees to pay the fees, costs, and expenses including reasonable attorneys' fees and expenses reasonably incurred by Rockwell Automation related to Rockwell Automation's enforcement of its rights or as result of a breach by Customer of its obligations under this Agreement.

15.6. Upon termination of this Agreement or any license hereunder, all of Customer's rights shall terminate. Customer will promptly discontinue use of and destroy any copies of the affected Software and Confidential Information in its possession or control and provide Rockwell Automation with a certificate signed by a duly authorized officer of Customer that it has complied with this provision.

15.7. Default by Rockwell Automation. If Rockwell Automation is in material default of its obligations in the Agreement, Customer shall give Rockwell Automation written notice, and Rockwell Automation shall have five (5) business days to begin action and ninety (90) business days (or longer if agreed to in writing) to cure the default. If Rockwell Automation fails to cure the default, Customer may terminate this Agreement to the extent that Rockwell Automation is in default. Rockwell Automation's liability shall be limited to (i) the proportionate Price paid for the terminated portion of the Work and (ii) any documented direct excess reprocurement costs incurred by Customer to complete the Work to a capability not exceeding that provided in the Scope of Work, but Rockwell Automation's liability for documented direct excess reprocurement costs shall be limited to one-hundred ten percent (110%) of any amounts paid for the terminated portion of the Work.

15.8. Convenience of Customer. Except as set forth in the applicable Scope of Work, Customer may terminate this Agreement for convenience prior to shipment by giving written notice to Rockwell Automation. Customer shall pay for any services performed before receipt of notice and any additional costs of termination (including third-party commitments, reasonable profit, and overhead as may be more specifically provided in the Scope of Work) upon submission of Rockwell Automation's invoices.

15.9. Delays or Default by Customer. If Customer, its employees, affiliates, other contractors to Customer, or any other party within Customer's reasonable control causes the delivery, installation, or acceptance of the Work to be delayed beyond the time period set forth in the Scope of Work, or if Customer materially breaches any terms or condition of the terms of this Agreement, Rockwell Automation may elect to: (i) withhold deliveries and suspend performance; or, (ii) place the Products in storage at Customer's risk and cost. If such delay or other non-fulfillment is not rectified by Customer within a reasonable time upon notice, Rockwell Automation may terminate this Agreement, and Customer shall pay all costs of termination (including third-party commitments, reasonable overhead, and profit) upon submission of Rockwell Automation's invoices.

15.10. Temporary Suspension of Work by Customer. Except as set forth in the applicable Scope of Work, Customer may, by providing prior written notice, request that Rockwell Automation temporarily suspend performance and delivery of the Work, in whole or in part. The notice shall specify the portion of the Work to be suspended, the effective date of suspension, Customer's anticipated duration of suspension, and the reasons for the suspension. Rockwell Automation shall suspend performance as requested, except as necessary for the care or preservation of Work previously executed. On or before the date the suspension begins, Customer must pay Rockwell Automation the unpaid balance of the portion of the Work previously executed plus any additional costs incurred by Rockwell Automation as a result of the suspension. Rockwell Automation shall resume the suspended Work after a change order is executed covering adjustments to the contract price, schedule, and any other affected terms or conditions resulting from the suspension. Unless otherwise agreed, the maximum cumulative period for suspension is sixty (60) days. Upon expiration of this or any shorter period agreed upon as provided above, Rockwell Automation may terminate this Agreement, and Customer shall pay all costs of cancellation (including third-party commitments, reasonable overhead, and profit) upon submission of Rockwell Automation's invoices.

15.11. All returns will be pursuant to Rockwell Automation's instructions.

16. Warranty.

16.1. Provided that Customer gives notice of any claimed breach of warranty within the warranty period, Rockwell Automation warrants to Customer for ninety (90) days after its delivery to Customer (the "Warranty Period") that: (i) the media on which the Software is delivered is free from defects in material and workmanship, and (ii) the Software performs in substantial conformity with any Rockwell Automation end-user documentation.

16.2. Rockwell Automation's warranties in this Section 16 shall not extend to warranty claims that result from: (i) Customer's failure to implement all updates issued by Rockwell Automation; (ii) modifications made by Customer to its operating environment or hardware that adversely affects the Software; (iii) any alterations or additions to the Software not performed by Rockwell Automation; (iv) failures in operation of the Software that are not reproducible in standalone form; (v) use of the Software that is in violation of this Agreement or that is not in accordance with the end user documentation therefore; (vi) failures which are caused by Customer's misuse, improper use or alteration of the Software or Customer's software or other software, hardware or products not licensed hereunder; (vii) any problem resulting from a change in the Designated Location; or (viii) any problem that results from causes that are unrelated to the usage of the Software such as fire, flood, earthquake, lighting strike, power failure or voltage surge.

16.3. For any Software that does not operate as warranted in this section, Customer's exclusive remedy and Rockwell Automation's sole liability shall be for Rockwell Automation to either repair or replace the Software, or if neither is commercially feasible, refund a pro-rata portion of the License Fee(s) paid, prorated over thirty-six (36) months from the date of this Agreement on a straight-line basis and terminate this Agreement.

16.4. Customer shall be fully responsible for: (i) the selection of the Software; (ii) the proper installation and use of the Software; (iii) verifying the results obtained from the use of the Software; and, (iv) taking appropriate measures to prevent loss of data. The limited warranty provided in Section 16.1 does not apply to any third party software provided by Rockwell Automation.

16.5. Warranty: Rockwell Automation warrants that service (including, but not limited to, training, installation, modifications, additions, software programming, engineering, startup, or repairs) shall be performed in a workmanlike manner conforming to standard industry practice. Rockwell Automation must receive written notification of non-conforming services within thirty (30) days after the services are provided. If such services are confirmed to be non-conforming, Rockwell Automation will, at its option, re-perform the service or provide a refund or credit to Customer in the amount paid for the service. The foregoing will be the exclusive remedies for any breach of warranty or breach of contract arising from warranted non-conforming services.

16.6. Remedies: Remedies under this warranty will be limited to, at Rockwell Automation's discretion, replacement, repair, re-performance, modification, or issuance of a credit for Price paid for the Work, but only after the return of such Products pursuant to Rockwell Automation's instructions. Replacement Products, at Rockwell Automation's discretion, may be new, remanufactured, refurbished, or reconditioned. If the repair, re-performance, or replacement does not cure the defective performance, Customer may request emergency on-site service, which will be at Rockwell Automation's expense (consisting of time, travel, and expenses incurred by Rockwell Automation related to such services). If the defective performance is not due to warranted defects in the Work the on-site service will be paid for by Customer. On-site warranty services performed at Rockwell Automation's expense shall not include removal or reinstallation costs related to large-scale assemblies such as motors or transformers. The foregoing will be the exclusive remedies for any breach of warranty or breach of contract arising from warranted defects.

16.7. General: Warranty satisfaction is available only if (i) Rockwell Automation is provided prompt written notice of the warranty claim, and (ii) Rockwell Automation's examination discloses that any alleged defect has not been caused by misuse, neglect, improper installation, operation, maintenance, repair, alteration, or modification by other than Rockwell Automation, accident, or unusual deterioration or degradation of the Products or parts thereof due to physical environment or electrical or electromagnetic noise environment.

16.8. THE ABOVE WARRANTIES ARE IN LIEU OF ALL OTHER WARRANTIES AND CONDITIONS, WHETHER EXPRESSED, IMPLIED OR STATUTORY, INCLUDING IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR USE.

17. **Support Services Warranty.** Rockwell Automation warrants that Support Services shall be performed in a workmanlike manner conforming to standard industry practice. Rockwell Automation must receive written notification of non-conforming Support Services within thirty (30) days after such services are provided. If such Support Services are confirmed to be non-conforming, Rockwell Automation will, at its option, re-perform the Support Services or provide a refund or credit to Customer in the amount paid for the applicable Support Services. The foregoing will be the exclusive remedies for any breach of warranty or breach of contract arising from warranted non-conforming Support Services.

18. **DISCLAIMER.** ROCKWELL AUTOMATION DISCLAIMS ANY AND ALL WARRANTIES OTHER THAN THOSE SPECIFICALLY SET FORTH IN THIS AGREEMENT. THE WARRANTIES CONTAINED HEREIN ARE IN LIEU OF ALL OTHER WARRANTIES AND CONDITIONS, WHETHER EXPRESSED, IMPLIED OR STATUTORY, INCLUDING IMPLIED WARRANTIES OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, NON-INFRINGEMENT, AND THAT THE SOFTWARE'S USE WILL BE ERROR FREE OR UNINTERRUPTED.

19. **Confidential Information.**

19.1. "Confidential Information" means: (i) the Software in Source Code and Scripting form; (ii) the technology, ideas, know how, documentation, processes, algorithms and trade secrets embodied in the Software; (iii) any software keys related to the Software; (iv) Software pricing; and, (iv) any other information in written or electronic media that is identified as "confidential," "proprietary" or with a similar legend at the time of such disclosure.

19.2. "Recipient" and "Discloser" shall refer to Customer and Rockwell Automation in their respective roles as both recipient and discloser of Confidential Information under this Agreement.

19.3. Each party will maintain in strict confidence all technical and business data and information disclosed by one party to the other that is marked "Confidential" and will not use or reveal such Information without the prior written authorization of the other.

19.4. The Recipient shall not use or disclose any Confidential Information, except as expressly authorized by this Agreement, and shall protect all such Confidential Information using the same degree of care which Recipient uses with respect to its own similarly valuable proprietary information, but in no event with safeguards less than a reasonably prudent business would exercise under similar circumstances. Recipient shall take prompt and appropriate action to prevent unauthorized use or disclosure of the Confidential Information.

19.5. The obligations of confidentiality and non-use will not apply to information (i) that is published or becomes part of the public domain other than by means of a breach of this Agreement; (ii) that the Recipient can prove by written documentation was known to it prior to disclosure by the Discloser; (iii) that the Recipient subsequently rightfully receives from a third party without an obligation of confidentiality; (iv) that the Discloser discloses to a third party on a non-confidential basis; or (v) that was independently developed by the Recipient.

19.6. If any Confidential Information must be disclosed to any third party by reason of legal, accounting or regulatory requirements beyond the reasonable control of the Recipient, the Recipient shall promptly notify the Discloser of the order or request and permit the Discloser (at its own expense) to seek an appropriate protective order.

20. Standard Software Product License and Ownership.

20.1. Standard Software Product Licenses. Rockwell Automation may provide, in addition to the Work identified in the Scope of Work, standard software applications regularly licensed to its customers under a click-wrap license agreement provided with such standard software applications. Such click-wrap license terms and conditions shall be the exclusive terms and conditions applicable to such standard software applications, excluding Customer's obligation to pay any license fee which shall be identified in the Scope of Work. All such standard software applications shall be identified in the Scope of Work, including the license fees therefore.

20.2. Except for any Customer or third-party confidential information, Rockwell Automation retains all right, title, and interest to the results of any services performed hereunder, documentation and application software developed by Rockwell Automation including the results of any Work. Customer shall not sublicense or assign the documentation or the software except to a Customer who purchases the Work from Customer. Customer may make an additional archival copy of such documentation and application software for backup.

20.3. Ownership of Pre-existing Intellectual Property. Each party shall own all right, title, and interest in all patents, trademarks, copyrights, confidential information, trade secrets, mask rights, and other intellectual property rights as it owned on the date of this Agreement.

20.4. No Other Licenses. Except as expressly set forth in this Agreement, no license under any patents, trademarks, copyrights, confidential information, trade secrets, mask rights, or other intellectual property rights is granted or implied by either party.

21. **Ownership of Intellectual Property.** The Software and documentation, including any modifications or enhancements, are protected by copyright and other intellectual property laws and treaties. Rockwell Automation or its licensors own any and all title, copyrights, and other intellectual property rights in the Software and documentation. The Software and documentation is licensed, not sold. Nothing in this Agreement constitutes a waiver of our rights under U.S. or International copyright law or any other law. To the extent that such ownership does not vest in Rockwell Automation by operation of law, Customer hereby assigns such ownership to Rockwell Automation. Customer will take all steps necessary to confirm Rockwell Automation's ownership of any and all such rights.

22. **Indemnification.** Rockwell Automation will pay costs and damages finally awarded in any suit against Customer to the extent based on a finding that the design of Software licensed hereunder by Rockwell Automation infringes any patent, utility model, copyright, or trademark granted or registered in the country of Rockwell Automation's shipping destination, provided that, Customer: (i) promptly informs Rockwell Automation of the alleged infringement in writing; (ii) provides Rockwell Automation the exclusive right to defend and settle the suit, at Rockwell Automation's expense; and, (iii) provides all reasonable information and assistance requested for the defense. Rockwell Automation shall have no liability for any infringement that is based upon or arises out of: (a) compliance with Customer's instructions, specifications or designs; (b) use of Software in a Customer or third-party process; or, (c) combinations with other equipment, software or materials not supplied by Rockwell Automation. In the event any Software is determined or believed by Rockwell Automation to infringe the rights of a third party, Rockwell Automation may, at its sole option and expense, elect to: (a) modify the Software so that it is non-infringing, (b) replace the Software with non-infringing Software that is functionally equivalent or superior in performance, (c) obtain a license for the Customer to continue to use the Software as provided hereunder, or (d) if none of the foregoing can be achieved despite the reasonable efforts of Rockwell Automation, terminate the license for the infringing Software, have the Customer return or destroy such Software, and refund to Customer the license fees paid by Customer for such Software, prorated over 60 months from the date of this Agreement on a straight-line basis plus the unused balance of any prepaid Software Support Fees. The foregoing states the sole and exclusive obligations of Rockwell Automation for intellectual property infringement. Rockwell Automation agrees to indemnify the Customer from any suit or proceeding by third parties (which are not Rockwell Automation employees) for damage to third-party tangible property and for bodily injury to the percentage extent directly caused by Rockwell Automation's negligence in the performance of this Agreement. This indemnity is contingent upon Customer giving Rockwell Automation prompt notice of any such suit or proceeding and all necessary information and assistance so that Rockwell Automation may defend or settle such claim and provided Customer does not take any adverse position in connection with such claim. If any such damage or injury is caused by

the joint or concurrent negligence of Rockwell Automation and Customer, or any agent, subcontractor, or supplier to Customer, each party shall pay for its own defense, and the liability of each party shall be borne in proportion to the party's negligence.

23. LIMIT OF LIABILITY. TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, IN NO EVENT SHALL ROCKWELL AUTOMATION OR ITS THIRD PARTY LICENSORS BE LIABLE FOR ANY BUSINESS INTERRUPTION OR LOSS OF PROFIT, REVENUE, MATERIALS, ANTICIPATED SAVINGS, DATA, CONTRACT, GOODWILL, OR THE LIKE (WHETHER DIRECT OR INDIRECT IN NATURE) OR FOR ANY OTHER FORM OF INCIDENTAL, INDIRECT, OR CONSEQUENTIAL DAMAGES OF ANY KIND. ROCKWELL AUTOMATION'S MAXIMUM CUMULATIVE LIABILITY RELATIVE TO ALL CLAIMS AND LIABILITIES, INCLUDING OBLIGATIONS UNDER ANY INDEMNITY, WHETHER OR NOT INSURED, WILL NOT EXCEED THE COST OF THE SOFTWARE GIVING RISE TO THE CLAIM OR LIABILITY. ROCKWELL AUTOMATION DISCLAIMS ALL LIABILITY RELATIVE TO GRATUITOUS INFORMATION OR ASSISTANCE PROVIDED BY BUT NOT REQUIRED OF ROCKWELL AUTOMATION. ANY ACTION BY EITHER PARTY MUST BE BROUGHT WITHIN 18 MONTHS AFTER THE CAUSE OF ACTION ACCRUES. THESE DISCLAIMERS AND LIMITATIONS OF LIABILITY WILL APPLY REGARDLESS OF ANY OTHER CONTRARY PROVISION AND REGARDLESS OF THE FORM OF ACTION, WHETHER IN CONTRACT, TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY), OR OTHERWISE. EACH PROVISION OF THIS AGREEMENT THAT PROVIDES FOR A LIMITATION OF LIABILITY, DISCLAIMER OF WARRANTY OR CONDITION OR EXCLUSION OF DAMAGES IS SEVERABLE AND INDEPENDENT OF ANY OTHER PROVISION. THIS PROVISION EXTENDS TO THE BENEFIT OF ROCKWELL AUTOMATION'S PARENT, SUBSIDIARIES, AFFILIATES, VENDORS, APPOINTED DISTRIBUTORS, AND OTHER AUTHORIZED RESELLERS AS THIRD-PARTY BENEFICIARIES.

24. **Customer Specification.** Unless otherwise specified in the Scope of Work, Rockwell Automation does not warrant or indemnify and will not otherwise be liable for (i) design, materials, or construction criteria furnished or specified by Customer and incorporated into the Work, (ii) products made by or sourced from other manufacturers or vendors specified by Customer, or (iii) commercially available computer software, hardware, and electrical components. (Such Customer-specified products shall include but not be limited to any identified in the Scope of Work.) Any warranty or indemnity applicable to such Customer-specified products will be limited solely to the warranty or indemnity, if any, extended by the original manufacturer or vendor other than Rockwell Automation to the extent permissible thereunder.

25. **Insurance.** During the term of this Agreement, Rockwell Automation shall maintain, at its sole expense, the following minimum insurance coverages:

25.1. Workers' Compensation: statutory in accordance with applicable law;

25.2. Employer's Liability: $1,000,000 per accident, per employee, per disease;

25.3. Commercial General Liability: $2,000,000 per occurrence single limit of liability, $2,000,000 general aggregate that shall include but not be limited to contractual liability, premises liability, advertising liability, and product liability; and

25.4. Commercial Automobile Liability: $2,000,000 per occurrence combined single limit of liability, covering all owned, leased, and non-owned vehicles.

26. **Third Party Software and Materials.** Customer agrees that: (i) the warranties and indemnities in this Agreement do not apply to any third party software or materials (even if furnished by Rockwell Automation hereunder), (ii) it will direct all claims relating to any third party software or materials directly to the third party and not to Rockwell Automation; and, (iii) any warranties and indemnities, if any, that relate to third party software or materials will be provided by such third party and not Rockwell Automation.

27. **High Risk Activities.** The Software is not fault-tolerant and is not designed, manufactured or intended for use or resale as a safety system in a manufacturing setting or in hazardous environments that requiring fail-safe performance in which the failure of the Software could lead to death, personal injury, or severe physical or environmental damage ("High Risk Activities"). Accordingly, the Customer acknowledges that it will install a control system sufficient to meet the relevant safety level certifications (ie. SIL 2, SIL 3, SIL 4). As such, the Customer (i) shall not to use Software with respect to any High Risk Activities and (ii) shall indemnify Rockwell Automation and its licensors from all losses, claims, damages, costs, attorneys' fees and other expenses relating to such High Risk Activities.

28. **Registration of Agreement.** Customer will be responsible for obtaining any permits or registrations required by any governmental body or regulatory agency for the import and use of the Software in any country in which Customer is permitted to use the Software or for Customer to make payments under this Agreement or for this Agreement to be enforceable.

29. **Force Majeure.** Neither party will be liable for any loss, damage or delay arising out of its failure (or that of its subcontractors) to perform due to causes beyond its reasonable control, including without limitation, acts of God, acts of civil or military authority, fires, strikes, floods, epidemics, quarantine restrictions, war, riots, acts of terrorism, delays in transportation, or transportation embargoes. In the event of such delay, performance date(s) will be extended as reasonably necessary to compensate for the delay.

30. **Customer Information.** Customer represents and warrants that it has the rights to the information provided or made available by Customer to Rockwell Automation, including but not limited to technical specifications, drawings, source code, application code, communication interfaces, protocols, and all other documentation, for Rockwell Automation to perform its obligations under this Agreement and that such access to and use of the information under this Agreement will not infringe or violate any agreement, confidentiality obligation, copyright, or other intellectual property right of the original vendor or

any other third party. Customer agrees to indemnify and hold harmless Rockwell Automation, its officers, directors, employees, agents, subsidiaries and affiliates, from any claims asserted arising out of Rockwell Automation's use of Information.

31. **Site Rules, Licenses, Permits, Site Preparation.**

31.1. Rockwell Automation agrees to comply with all applicable posted site rules of Customer (unless inconsistent with the obligations set forth in the Scope of Work) and any additional Customer's site rules that have been incorporated into the Scope of Work.

31.2. Customer is responsible for:

31.2.1. All licenses, permits, clearances, and site access rights;

31.2.2. All sites being ready and equipped with all necessary Customer furnished equipment and facilities;

31.2.3. Any required Customer fixtures or facilities being hazard free, structurally sound, and sufficient; as required for installing, commissioning or using the Work. Properly using, calibrating operating, monitoring and maintaining the Work consistent with all Rockwell Automation or third-party provided instructions, warnings, recommendations and documentation;

31.2.4. Ensuring that only properly trained personnel use, operate and maintain the Work at all times.

31.2.5. All other factors affecting the Work that are outside of the direct control of Rockwell Automation.

32. **Customer Responsibilities.** Customer will: (i) provide Rockwell Automation access to, and use of, all information, data, documentation, facilities, working space and office services reasonably necessary; (ii) appoint a representative who will provide a professional and prompt liaison with Rockwell Automation; (iii) ensure that the appointed representative is available at all times when Rockwell Automation's personnel are at the project site (or designate an alternate with the same level of authority); (iv) require its third party suppliers to provide Rockwell Automation access and the right to use all information, including but not limited to technical specifications, drawings, source code, communication interfaces, protocols, and all other documentation that Rockwell Automation deems reasonably necessary to perform its work under this Agreement ("Information"); and (v) confer with the Rockwell Automation representative at regular intervals to review progress and resolve any issues relating to the Work. Customer will be responsible for the performance of its employees and agents and for the accuracy and completeness of all data and information provided to Rockwell Automation.

33. **Government Restricted Rights.** If Customer is a branch or agency of the United States Government, the following provision applies. The Software and documentation are comprised of "commercial computer software" and "commercial computer software documentation" as such terms are used in 48 C.F.R. 12.212 (SEPT 1995) and are provided to the Government (i) for acquisition by or on behalf of civilian agencies, consistent with the policy set forth in 48 C.F.R. 12.212; or (ii) for acquisition by or on behalf of units of the Department of Defense, consistent with the policies set forth in 48 C.F.R. 227.7202-1 (JUN 1995) and 227.7202-3 (JUN 1995).

34. **Export Control.** The Software and associated materials supplied or licensed hereunder may be subject to various export laws and regulations. Notwithstanding any other provision to the contrary, if U.S. or local law requires export authorization for the export or re-export of any Software or associated technology, no delivery can be made until such export authorization is obtained, regardless of any otherwise promised delivery date. If any required export authorization is denied, Rockwell Automation will be relieved of any further obligation relative to the sale and/or license and delivery of the Software without liability of any kind to Customer or any other party. Rockwell Automation will not comply with boycott related requests except to the extent permitted by U.S. law and then only at Rockwell Automation's sole discretion.

35. **Assignment.** This Agreement may not be assigned in whole or in part by Customer without the prior written consent of Rockwell Automation. However, consent will not be unreasonably delayed or denied for assignments between a party and its parent company, subsidiaries, or affiliates as part of a consolidation, merger, or any other form of corporate reorganization.

36. **Employee Solicitation.** During the term of this Agreement and for twelve 12 months following its termination, Customer agrees that if it hires any employee of Rockwell Automation with whom the Customer has had contact as a result of this Agreement, it will pay Rockwell Automation 50% of the hired Rockwell Automation employee's annual salary (including any bonuses) at Rockwell Automation.

37. **Independent Contractors.** The parties at all times will be independent. Neither party is an employee, joint venture, agent or partner of the other; neither party is authorized to assume or create any obligations or liabilities, express or implied, on behalf of, or in the name of the other. The employees, methods, facilities, and equipment of each party at all times will be under the exclusive direction and control of that party.

38. **Disputes.** The parties will attempt in good faith to promptly resolve any dispute by negotiations between representatives who have authority to settle the dispute. If unsuccessful, the parties will attempt in good faith to settle the dispute by non-binding third-party mediation, with mediator fees and expenses apportioned equally to each side. Any dispute not resolved by negotiation or mediation may then be submitted to a court of competent jurisdiction in accordance with the terms provided in this Agreement. These procedures are the exclusive procedures for the resolution of disputes between the parties.

39. **Governing Law and Forum.** This Agreement and all disputes arising under it will be governed by and interpreted in accordance with the internal laws and will be subject to the exclusive jurisdiction of the courts of the state, province, or other governmental jurisdiction in which Rockwell Automation's principal place of business resides but specifically excluding the provisions of the 1980 UN Convention on Contracts for the International Sales of Goods.

40. **Government Clauses and Contracts.** No government contract clauses, specification, or regulations apply to the Work, Products, or otherwise to this Agreement except to the extent agreed in writing by Rockwell Automation.

41. **Saverability.** If a provision of this Agreement is found unenforceable by law, the remainder of this Agreement shall continue in full force and effect. A delay or failure in enforcing any right or remedy under this Agreement shall not prejudice or operate to waive that right or remedy.

42. **No Waiver.** A delay or failure in enforcing any right or remedy under this Agreement shall not prejudice or operate to waive that right or remedy.

43. **Counterparts.** This Agreement may be executed in multiple counterparts.

44. **Sections.** The License Fee(s), Support Fee(s), Term and Termination, Disclaimer, Confidential Information, Ownership of Intellectual Property, Limit of Liability, and High Risk Activities provisions will survive any expiration or termination of this Agreement. All rights and obligations which by their nature survive the expiration or termination of this Agreement will remain in effect beyond expiration or termination.

45. **Notices.** Written notice will be deemed to have been given when the notifying party delivers such notice to the other party or has sent such notice to the other party by certified or registered mail or facsimile (with confirming letter to follow), directed to the addresses set forth above (unless written notice of a change of address has been given in accordance with this paragraph)

46. **Languages.** The parties acknowledge that they have required that the Agreement evidenced hereby be drawn up in English. Les parties reconnaissent avoir exigé la rédaction en anglais du Contrat. In the event of a conflict between the English and other language versions, the English version will prevail.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

April 19, 2011

Mr. Douglas Findley
Environmental Engineer
Land O'Lakes, Inc.
400 South M Street
Tulare, CA 93274-5431

Re: Approval of Parametric Emission Monitoring System for Boiler #8 (SJVAPCD Permit Unit PTO S-525-42)

Dear Mr. Findley:

By letter dated August 26, 2010, Land O'Lakes ("LOL") petitioned EPA for approval of an alternative NO_x monitoring method in lieu of a continuous emission monitoring system ("CEMS"), pursuant to the provisions of 40 C.F.R. § 60.13(i), for Boiler #8, which currently operates under San Joaquin Valley Air Pollution Control District ("SJVAPCD") permit PTO# S-525-42. This natural gas-fired boiler is subject to New Source Performance Standards ("NSPS") for Industrial-Commercial-Institutional Steam Generating Units (40 C.F.R. Part 60, Subpart Db.) By letter dated August 6, 2010, LOL also submitted to EPA a report of the initial 30-day compliance test using CEMS for Boiler #8.

EPA has reviewed the documents submitted by LOL and hereby approves LOL's request to operate an alternative NO_x parametric (predictive) emission monitoring system ("PEMS") for Boiler #8 in lieu of NO_x CEMS subject to the following conditions:

1. At all times the PEMS must be operated in accordance with the requirements contained in EPA Performance Specification 16 for Predictive Emissions Monitoring Systems and Amendments to Testing and Monitoring Provisions. See 56 Fed. Reg. 12575 (March 25, 2009);

2. All records related to the operation of the PEMS that are required by NSPS Subpart Db and EPA Performance Specification 16 must be kept in a form suitable for inspection for a period of at least five (5) years; and

3. LOL must submit a permit application to the SJVAPCD (with a copy to EPA, attn: Mark Sims, AIR-5) requesting that the District modify LOL's Title V permit to incorporate all applicable EPA Performance Specification 16 requirements for LOL Boiler #8.

If you have any questions concerning this PEMS approval letter, please contact Mark Sims of my staff at 415-972-3965.

Sincerely,

Douglas K. McDaniel, Chief
Enforcement Office
Air Division

cc: Mr. Rahul Pendse (Trinity Consultants)
Mr. Richard Edgehill (SJVAPCD)
Mr. Greg Lafore (SJVAPCD)

ATTACHMENT IV
Emissions Profile

Application Emissions

Permit #: S-525-51-1	**Last Updated**	
Facility: LAND O' LAKES INC	09/26/2017	EDGEHILR

Equipment Pre-Baselined: NO

	NOX	SOX	PM10	CO	VOC
Potential to Emit (lb/Yr):	9725.0	4533.0	12117.0	58990.0	8769.0
Daily Emis. Limit (lb/Day)	26.6	12.4	33.2	161.6	24.0
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	2431.0	1136.0	3029.0	14747.0	2192.0
Q2:	2431.0	1136.0	3029.0	14747.0	2192.0
Q3:	2431.0	1136.0	3029.0	14747.0	2192.0
Q4:	2432.0	1136.0	3029.0	14747.0	2192.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio	1.5		1.0		1.0
Quarterly Offset Amounts (lb/Qtr)					
Q1:	3402.0		3006.0		819.0
Q2:	3402.0		3006.0		820.0
Q3:	3402.0		3007.0		820.0
Q4:	3402.0		3007.0		820.0

ATTACHMENT V
AAQA and HRA

San Joaquin Valley Air Pollution Control District
Risk Management Review
REVISED

To:	Richard Edgehill – Permit Services
From:	Cheryl Lawler – Technical Services
Date:	January 13, 2016
Facility Name:	Land O Lakes
Location:	400 South M Street, Tulare
Application #(s):	S-525-51-0
Project #:	S-1153671

A. RMR SUMMARY

RMR Summary			
Categories	**Natural Gas Boiler (Unit 51-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	0.61	0.61	>1.0
Acute Hazard Index	0.00	0.00	0.00
Chronic Hazard Index	0.00	0.00	0.00
Maximum Individual Cancer Risk (10^{-6})	0.37	0.37	0.37
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 51-0

1. 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]

B. RMR REPORT

I. Project Description

Technical Services received a request on January 11, 2016, to re-run a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for a new 182 MMBtu/hr natural gas boiler. The project is being re-run because of revised daily and hourly NOX emission rates used for the AAQA.

II. Analysis

Technical Services performed a prioritization using the District's SHARP database. Since the facility's prioritization scores totaled to greater than one, a refined health risk assessment was required. Emissions were calculated using 2001 Ventura County emission factors for external combustion of natural gas and were input into the SHARP database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2007-2010 from Visalia to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP) and the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) 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			
Source Type	Point	**Location Type**	Urban
Stack Height (m)	13.41	**Closest Receptor (m)**	122
Stack Diameter (m)	1.52	**Type of Receptor**	Residence
Stack Exit Velocity (m/s)	9.04	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	422	**Natural Gas Usage Rates (MMscf)**	0.182 hr 1594 yr

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The revised emission rates used for criteria pollutant modeling were calculated and supplied by the processing engineer.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Diesel ICE	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
$PM_{2.5}$	X	X	X	Pass[2]	Pass[2]

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010, using the District's approved procedures.
[2]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 Cancer Risk factor associated with the project 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 permit conditions listed on Page 1 of this report must be included for this proposed unit.

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
Emissions Speciation Worksheet
Prioritization
AAQA Results
Facility Summary
AERMOD Non-Regulatory Option Checklist

ATTACHMENT VI
BACT Analysis

Top Down BACT Analysis for the Boiler

Steady State

1. BACT Analysis for NO_X Emissions:

a. Step 1 - Identify all control technologies

BACT Clearinghouse Guideline 1.1.2 applicable for boilers with > 20.0 MMBtu/hr, natural gas fired, base-loaded or with small load swings was rescinded as requirements were less stringent than District Rule 4320. Therefore, the current BACT requirements reflect District Rule 4320 emissions limits for steam generators with heat input ratings greater than 20 MMBtu/hr. The Standard and Enhanced Schedule options of 7 ppm @ 3% O_2 and 5 ppm @ 3% O_2 (listed in the table below) are considered Achieved in Practice and Technologically feasible BACT requirements, respectively.

<table>
<tr><th colspan="5">Rule 4320 Emissions Limits</th></tr>
<tr><th rowspan="2">Category</th><th colspan="2">Operated on gaseous fuel</th><th colspan="2">Operated on liquid fuel</th></tr>
<tr><th>NOx Limit</th><th>CO Limit</th><th>NOx Limit</th><th>CO Limit</th></tr>
<tr><td rowspan="2">A. Units with a total rated heat input > 20.0 MMBtu/hr, except for Categories C through G units</td><td>a) Standard Schedule 7 ppmv or 0.008 lb/MMBtu; or</td><td rowspan="2">400 ppmv</td><td rowspan="2">40 ppmv or 0.052 lb/MMBtu</td><td rowspan="2">400 ppmv</td></tr>
<tr><td>b) Enhanced Schedule 5 ppmv or 0.0062 lb/MMBtu</td></tr>
</table>

Therefore, the following are possible control technologies:

1) 5 ppmvd @ 3% O_2 with SCR – Technologically Feasible
2) 7 ppmvd @ 3% O_2 – Achieved-in-Practice

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) 5 ppmvd @ 3% O_2 with SCR – Technologically Feasible
2) 7 ppmvd @ 3% O_2 – Achieved-in-Practice

d. Step 4 - Cost Effectiveness Analysis

A cost effective analysis is required for technologically feasible control options that are not proposed. The applicant is proposing a NO_x limit of 5 ppmvd @ 3% O_2; therefore, a cost effective analysis is NOT required for the 5 ppmvd option (SCR).

e. Step 5 - Select BACT

The applicant has proposed to install a boiler with a NO_x limit of 5 ppmvd @ 3% O_2; therefore BACT for NO_x emissions is satisfied.

2. BACT Analysis for SO_x Emissions:

Oxides of sulfur (SO_x) emissions occur from the combustion of the sulfur, which is present in the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for SO_x emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of

sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

d. Step 4 - Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for SO_X emissions is natural gas fuel with a sulfur content ≤1 gr-S/100 scf; therefore BACT for SO_X emissions is satisfied.

3. BACT Analysis for PM_{10} Emissions:

Particulate matter (PM_{10}) emissions result from the incomplete combustion of various elements in the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for CO_{10} emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr of sulfur compounds (as S) per 100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

d. Step 4 - Cost Effectiveness Analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for PM10 emissions is natural gas fuel with a sulfur content ≤1 gr-S/100 scf; therefore BACT for PM10 emissions is satisfied.

4. BACT Analysis for CO Emissions:

Carbon monoxide (CO) emissions are generated from the incomplete combustion of air and fuel.

a. Step 1 - Identify all control technologies

The District is current developing a BACT Guideline (in draft form) for boilers. Based on a review of existing Distract permits and technologies the control technologies are

1) 50 ppmvd @ 3% O_2
2) natural gas fuel

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) 50 ppmvd @ 3% O_2
2) Natural gas fuel

d. Step 4 - Cost Effectiveness Analysis

The application meets the requirements of both of the above technologies. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for CO emissions is a CO limit of 50ppmvd @ 3% O_2 and natural gas fuel which has been proposed. Therefore BACT for CO emissions is satisfied.

5. BACT Analysis for VOC Emissions:

Volatile organic compounds (VOC) emissions are generated from the incomplete combustion of the fuel.

a. Step 1 - Identify all control technologies

The SJVUAPCD BACT Clearinghouse guideline 1.2.1, 1st quarter 2005, identifies for achieved in practice BACT for VOC emissions from oil field steam generators ≥5 MMBtu/hr as follows:

1) Gaseous fuel

No technologically feasible alternatives or control alternatives identified as alternate basic equipment for this class and category of source are listed.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Gaseous fuel

d. Step 4 - Cost effectiveness analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for VOC emissions for the boiler is gaseous fuel. The applicant has proposed to install a boiler fired on gaseous fuel; therefore BACT for VOC emissions is satisfied.

PEMS Training

During the PEMS Training Period, not to exceed 30 days, NOx control will be low NOx burner only. SCR may or may not be used at any given time. NOx emissions are limited to 20 ppmv NOx @ 3% O2. No increase from steady state SOx, PM10, CO, and VOC emissions is expected during PEMS Training.

BACT Analysis for NOx Emissions:

a. Step 1 - Identify all control technologies

Low NOx burner that achieves 20 ppmv NOx @ 3% O2 – Low NOx Burner

Operator shall perform expeditious completion of PEMS Training activities not to exceed cumulative 30 days after commissioning of the boiler (i.e. installation of boiler, connection of gas pipelines, initiate fuel flow, installation of control systems, etc)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1. Low NOx burner that achieves 20 ppmv NOx @ 3% O2 – Low NOx Burner

2. Operator shall perform expeditious completion of PEMS Training activities not to exceed cumulative 30 days after commissioning of the boiler (i.e. installation of boiler, connection of gas pipelines, initiate fuel flow, installation of control systems, etc).

d. Step 4 - Cost effectiveness analysis

The only control technology in the ranking list from Step 3 has been achieved in practice. Therefore, per the District's BACT Policy (dated 11/9/99) Section IX.D.2, the cost effectiveness analysis is not required.

e. Step 5 - Select BACT

BACT for NOx emissions for the boiler is low NOx burner that achieves 20 ppmv NOx @ 3% O2 and expeditious completion of PEMS Training activities not to exceed cumulative 30 days after commissioning of the boiler; therefore BACT for NOx emissions is satisfied.

ATTACHMENT VII
Title V Compliance Certification Form
Statewide Compliance Statement

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: Land O' Lakes, Inc.	FACILITY ID: S-525
1. Type of Organization:[X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility	
2. Owner's Name: Land O' Lakes, Inc.	
3. Agent to the Owner: Douglas W. Findley	

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

(MG) 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).

(MG) 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.

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

(MG) 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:

[signature] 9/3/2015

Signature of Responsible Official Date

Michael ~~Garcia~~ Gracia

Name of Responsible Official (please print)

Tulare Plant Manager

Title of Responsible Official (please print)

CERTIFICATION

Land O'Lakes hereby certifies as follows:

1. Land O'Lakes owns or operates one major stationary sources in the State of California. Such source is comprised of a vast number of emission points. As used in this certification, the term "major stationary source" shall, with respect to Land O'Lakes stationary source in the SJVUAPCD, have the meaning ascribed thereto in SJVAPCD Rule 2201, Section 3.23.

2. Subject to paragraphs 3 and 4 below, the stationary source owned or operated by Land O'Lakes in the State of California is either in compliance, or on an approved schedule of compliance, with all applicable emission limitations and standards under the Clean Air Act and all of the State Implementation Plan approved by the Environmental Protection Agency.

3. This certification is made on information and belief and is based upon a review of Land O'Lakes major stationary source in the State of California by those employees of Land O'Lakes who have operational responsibility for compliance. In conducting such reviews, Land O'Lakes and its employees have acted in good faith and have exercised best efforts to identify any exceedance of the emission limitations and standards referred to in paragraph 2 thereof.

4. This certification shall speak as of the time and date of its execution.

CERTIFICATION

By: [signature]

Title: Plant Manager Date: Sept 18, 2015

ATTACHMENT VIII
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-525-51-1 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: LAND O' LAKES INC
MAILING ADDRESS: 400 SOUTH M ST
TULARE, CA 93274

LOCATION: 400 SOUTH M ST
TULARE, CA 93274

EQUIPMENT DESCRIPTION:
MODIFICATION OF 182 MMBTU/HR BABCOCK AND WILCOX COMPANY NATURAL GAS FIRED BOILER WITH COEN/TODD VARIFLAME LOW NOX BURNER (OR EQUIVALENT), CATASTAK SCR SYSTEM (OR EQUIVALENT), AND A PREDICTIVE EMISSION MONITORING SYSTEM (PEMS): REVISED OFFSETTING PROPOSAL

CONDITIONS

1. {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
2. {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
3. ATC S-525-51-0 is hereby cancelled. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOX emission reduction credits for the following quantity of emissions: 1st quarter - 3,402 lb, 2nd quarter - 3,402 lb, 3rd quarter - 3,402 lb, and fourth quarter - 3,402 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/08/16) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
5. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 819 lb, 2nd quarter - 820 lb, 3rd quarter - 820 lb, and fourth quarter - 820 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 2/08/16). [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 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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Arnaud Marjollet, Director of Permit Services

S-525-51-1 : Sep 28 2017 12:48PM -- EDGEHILR : Joint Inspection NOT Required

6. Prior to operating equipment under this Authority to Construct, permittee shall withdraw sufficient PM10 emission reduction credits to offset the following quantity of emission increases: 1st quarter - 3,006 lb, 2nd quarter - 3,007 lb, 3rd quarter - 3,007 lb, and fourth quarter - 3,007 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 2/08/16). SOx ERCs may be used to offset PM10 at an interpollutant offset ratio of 1:1. [District Rule 2201] Federally Enforceable Through Title V Permit

7. ERC Certificate Number S-3326-2, S-3625-2, C-1393-2, S-4710-2, N-1371-2, S-3284-1, S-3625-1, C-1044-1, S-4714-1, N-1373-1, S-4658-1, S-3625-4, S-3625-5, S-3352-5, C-1392-5, N-1372-5, N-1375-5, S-4716-5, N-1374-4, and S-4712-4 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

8. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201] Federally Enforceable Through Title V Permit

9. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201] Federally Enforceable Through Title V Permit

10. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit

11. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201] Federally Enforceable Through Title V Permit

12. Permit to Operate S-525-2-8 shall be cancelled upon implementation of ATC. [District Rule 2201] Federally Enforceable Through Title V Permit

13. {15} 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]

14. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201] Federally Enforceable Through Title V Permit

15. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4201] Federally Enforceable Through Title V Permit

16. 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 60.49 b(d)(1)] Federally Enforceable Through Title V Permit

17. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

18. The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201] Federally Enforceable Through Title V Permit

19. Upon completion of initial commissioning of boiler (i.e. installation of boiler, connection of gas pipelines, initiate fuel flow, installation of control systems, etc) initial PEMS training and testing period shall not exceed 30 consecutive days. [District Rule 2201] Federally Enforceable Through Title V Permit

20. NOx emissions during Prediction Emissions Monitoring System (PEMS) training period shall not exceed 106.1 lb/day. Record of lb/day NOx and CO emissions during PEMs training shall also be kept. [District Rule 2201] Federally Enforceable Through Title V Permit

21. NOx emissions, including PEMS Training, shall not exceed 9725 lb/yr. [District Rule 2201]

22. NOx emissions shall not exceed 20 ppmv @ 3% O2 averaged over a 30-day PEMs initial training period. [District Rule 2201] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

57. For the initial RATA, source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of completion of PEMS training period. [District Rules 2201, 4305, 4306 and 4320, 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

58. Source testing to measure NH3 slip from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 40 CFR Part 64] Federally Enforceable Through Title V Permit

59. Source testing to measure NH3 slip from this unit shall be conducted at least once every twelve months or shall meet the alternate monitoring method established by mutual agreement with the District . After demonstrating compliance on two consecutive annual source tests, the unit shall be tested not less than once 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 twelve months. [District Rules 4102, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

60. For the initial and subsequent RATA, 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

61. For the initial and subsequent RATA, 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

62. For the initial and subsequent RATA, 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

63. For the initial and subsequent RATA, fuel sulfur content shall be determined using EPA Method 11 or Method 15. [District Rule 4320] Federally Enforceable Through Title V Permit

64. For the initial and subsequent RATA, source testing for ammonia slip shall be conducted utilizing BAAQMD method ST-1B. [District Rule 2201] Federally Enforceable Through Title V Permit

65. 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

66. For the initial and subsequent RATA, 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

67. Permittee shall determine sulfur content of combusted gas annually or shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081 and 4320] Federally Enforceable Through Title V Permit

68. Permittee shall record the daily startup and shutdown duration times of the boiler. [District Rules 2201, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

69. All records related to the operation of the PEMS that are required by NSPS Subpart Db, 40 CFR Part 64 and EPA Performance Specification 16 must be kept in a form suitable for inspection for a period of at least five (5) years. [District Rule 1080] Federally Enforceable Through Title V Permit

70. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070] Federally Enforceable Through Title V Permit

45. If PEMS fails to pass a quarterly RAA or yearly RATA test , or if changes are made that could result in a significant change in the emissions rate (e.g. process modification, new process operating modes, or changes to emission controls) the PEMS must be recertified by the earlier of 60 operating days or 180 calendar days after the failed RATA or after the change that has caused a significant change in emission rate as specified in PS-16, Section 8.5. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

46. Source shall maintain a Quality Control Plan (QA plan) including the components specified by PS-16, Section 9.0 to verify that the system is generating quality assured data after the initial PEMS certification test. QA plan shall include QA/QC summary of ongoing tests (listed in PS-16 Section 9.1 Table), daily sensor evaluation checks, quarterly RAAs, and yearly RATA. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

47. The operator shall monitor the ammonia injection rate during PEMS breakdowns to demonstrate NOx emission compliance. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

48. The PEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

49. PEMS emission measurements shall be averaged over a period of 15 consecutive minutes to demonstrate compliance with the applicable emission limits. [District Rules 4306 and 4320] Federally Enforceable Through Title V Permit

50. The PEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h), or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080] Federally Enforceable Through Title V Permit

51. The nitrogen oxide NOx emission rates measured by the PEMS shall be expressed in lb/million Btu or ppmv @ 3% O2. The 1-hour average emission rates shall be calculated using the data points required under Section 60.13(h)(2). The records shall also include a daily emission rate consisting of an averaged 24 hour rolling emission rate. [District Rule 2201; 40 CFR 60.48b (d) and 40 CFR Part 64] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain PEMS records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and emission measurements. [40 CFR 60.7(b), and District Rule 1080] Federally Enforceable Through Title V Permit

53. Permittee shall submit a PEMS written report for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter. Quarterly report shall include: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; applicable time and date of each period during which the PEMS was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [40 CFR Subpart Db, 40 CFR Part 64, District Rule 1080 and District Rule 2520] Federally Enforceable Through Title V Permit

54. 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

55. The initial PEMS training and testing and 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

56. 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

CONDITIONS CONTINUE ON NEXT PAGE

36. Details on the design of the PEMS (PEMS protocol) as specified in PS-16, Section 6.1 must be approved by the District prior to the start of the PEMS training period. This information must include number of input parameters, parameter operating envelope, source specific operating conditions affecting PEMS output, ambient conditions affecting PEMS operation, PEMS principal of operation including physical assumptions and mathematical manipulations supporting its operation, specific details on the testing to be performed for the PEMs training, data recorder scale, sensors to be used and sensor evaluation system, plan to detect and notify operator of parameter envelope exceedences, and recordkeeping. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

37. Initial Relative Accuracy Test Audit (RATA) must be conducted as specified in PS-16, Section 8.2 and must include 9 RM (Reference Method e.g. EPA Method 7c for NOx) tests at each of low, medium, and high operating levels. Relative accuracy (RA) calculations using RM and PEMS data from the 3-level tests must be done using equations specified in PS-16, Section 12.2. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

38. PEMS RA must not exceed 10 percent if the PEMS measurements are greater than 100 ppm or 0.2 lb/MMBtu. The RA must not exceed 20 percent if the PEMS measurements are between 100 ppm (or 0.2 lb/MMBtu) and 10 ppm (or 0.05 lb/MMBtu). For measurements below 10 ppm, the absolute mean difference between the PEMS measurements and the RM measurements must not exceed 2 ppm. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

39. Permittee shall perform a relative accuracy audit (RAA) consisting of at least three 30-minute portable analyzer or RM (reference method) determinations each quarter a relative accuracy test audit (RATA) is not performed as specified in Section 9.3 of EPA Performance Specification 16. The average of the 3 portable analyzer determinations must not differ from the simultaneous PEMS average value by more than 2 ppmv. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

40. If a PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly (RATA) in the second year, the permittee may elect to perform a single mid-year RAA in the second year in place of the quarterly RAAs as specified in Section 9.3 of EPA Performance Specification 16. This option may be repeated, but only until the PEMS fails either a mid-year RAA or a yearly RATA. When such a failure occurs, permittee must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMS successfully passes both a year of quarterly RAAs and a subsequent RATA. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

41. Statistical tests as specified PS-16, Section 8.3 including bias test, F-test, and correlation analysis must be used to evaluate paired RA and RM data for demonstration of continual compliance. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

42. The PEMS data is considered biased and must be adjusted if the arithmetic mean (d) is greater than the absolute value of the confidence coefficient (cc) in Equations 16.1 and 16.3 of EPA Performance Specification 16. In such cases, a bias factor must be used to correct the PEMS data. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

43. The calculated F-value (as specified in Section 13.3 of EPA Performance Specification 16) shall not exceed the critical F-value at the 95-percent confidence level for the PEMS to be acceptable. [District Rules 1080, 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

44. Operator shall perform a correlation analysis using the RA paired data from all operating levels combined to determine how well the RM and PEMS correlate. Use the equations in Section 12.3.3. The correlation is waived if the process cannot be varied to produce a concentration change sufficient for a successful correlation test because of its technical design. In such cases, should a subsequent RATA identify a variation in the RM measured values by more than 30 percent, the waiver will not apply, and a correlation analysis test must be performed at the next RATA. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64]

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CONDITIONS CONTINUE ON NEXT PAGE

23. Permittee shall monitor and record the stack concentration of NOx continuously using CEMS during PEMs training period. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

24. Except during startup and shutdown and 30-day PEMs training period, emissions rates from the natural gas-fired unit shall not exceed any of the following limits: 5 ppmv NOx @ 3% O2 or 0.0061 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 50 ppmv CO @ 3% O2 or 0.037 lb-CO/MMBtu, 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320] Federally Enforceable Through Title V Permit

25. NOx emissions limits shall not exceed 0.1 lb NOx/MMBtu for low heat release rate (< 70,000 Btu/hr ft2) and 0.2 lb NOx/MMBtu for low heat release rate (> 70,000 Btu/hr ft2) pursuant to 40 CFR 60.44b(a). This limit applies at all times including startups, shutdowns, and malfunctions pursuant to CFR 60.42b(h). Compliance with these limits is determined on a 24-hr average basis for the initial performance test and on a 3 hour average basis for subsequent performance tests pursuant to 40 CFR 60.44b(j). [40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

26. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 3% O2. [District Rule 4102] Federally Enforceable Through Title V Permit

27. PEMS or Continuous Emissions Monitoring System (CEMS) shall be certified within 60 days of completion of PEMs training period. [NSPS Subparts A and Subpart Db] Federally Enforceable Through Title V Permit

28. During startup or shutdown, the emissions control system shall be in operation, and emissions shall be minimized to the extent technically possible. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

29. During initial PEMS training and testing period, the allowable duration of a start-up shall not exceed 12 hours per occurrence and the allowable duration of shutdown shall not exceed 9 hours per occurrence. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

30. Except during initial PEMS training and testing period, startup and shutdown shall not exceed 2 hrs per occurrence. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit

31. If CEMS is installed, unit shall comply with the emission monitoring requirements as specified in 40 CFR Part 60.48b. [District Rule 4001] Federally Enforceable Through Title V Permit

32. If PEMS is installed for NOx and CO, PEMS shall meet the requirements in 40 CFR 60, Performance Specifications 16 (PS-16) except as modified by this permit, or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [40 CFR Subpart Db, 40 CFR Part 64, Rule 4320, and, District Rule 1080] Federally Enforceable Through Title V Permit

33. Permittee shall submit to the District for approval a plan (PEMS plan) that identifies the operating conditions to be monitored under 40 CFR 60.48b (g)(2) and the records to be maintained under 60.49b and Rule 4320. This plan shall be submitted to the District for approval at least 30 days prior to the start of the PEMS training period. [40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

34. At all times the PEMS must be operated in accordance with the requirements contained in EPA Performance Specification 16 for Predictive Emissions Monitoring Systems and Amendments to Testing and Monitoring Provisions. [District Rule 1080] Federally Enforceable Through Title V Permit

35. The owner or operator shall install, certify, maintain, operate and quality-assure a PEMS which continuously predicts and records the exhaust gas NOx, CO and O2 concentrations. Predictive emissions monitor(s) shall be capable of predicting emissions during normal operating conditions. PEMS results during startup and shutdown events shall be predicted using startup emission rates obtained from the initial performance source testing to determine compliance with emission limits contained in this permit. [District Rules 2201, 4305, 4306, 4320 and 40 CFR Subpart Db, 40 CFR Part 64] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE