San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUG 16 2017

Tim Alburger
Seneca Resources
4800 Corporate Court
Bakersfield, CA 93311

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-4159
Project Number: S-1171562

Dear Mr. Alburger:

Enclosed for your review and comment is the District's analysis of Seneca Resources's application for an Authority to Construct for a heater, in western Kern County, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice and 45-day EPA notice comment periods, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Richard Edgehill of Permit Services at (661) 392--5617.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rue

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

10 MMBtu/hr Heater Treater

Facility Name:	Seneca Resources	Date:	August 7, 2017
Mailing Address:	4800 Corporate Court	Engineer:	Richard Edgehill
	Bakersfield, CA 93311	Lead Engineer:	Steve Leonard
Contact Person:	Tim Alburger		
Telephone:	(661) 399-4270 #3544		
Fax:	(661) 399-7706		
Application #(s):	S-4159-7-3 and 10-0		
Project #:	1171562		
Deemed Complete:	April 26, 2017		

I. PROPOSAL

Seneca Resources (Seneca) has requested an Authority to Construct (ATC) for a 10 MM Btu/hr heater treater (ATC S-4159-10-0). Collected vapors from the heater treater will be directed to the existing and permitted Thermally Enhanced Oil Recovery (TEOR) System S-4159-7.

Note that the fugitive emissions components associated with the new heater treater will process gas expected to contain less than 10% VOCs by wt. Therefore, according to District policy SSP 2015, fugitive emissions are not assessed. Further note that the change to TEOR operation S-4159-7 is not a NSR modification as there is no change in equipment (fugitve emissions components), emissions, or permit conditions.

The project is a Federal Major Modification. BACT, offsets and public notice are required.

II. APPLICABLE RULES

District Rule 2201	New and Modified Stationary Source Review Rule (2/18/16)
District Rule 2410	Prevention of Significant Deterioration (6/16/11)
District Rule 2520	Federally Mandated Operating Permits (6/21/01)
District Rule 4001	New Source Performance Standards (4/14/99)
District Rule 4101	Visible Emissions (2/17/05)
District Rule 4102	Nuisance (12/17/92)
District Rule 4201	Particulate Matter Concentration (12/17/92)
District Rule 4301	Fuel Burning Equipment (12/17/92)
District Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
District Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
District Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
District 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 heater treater will be located within Seneca's heavy oil western stationary source (facilities S-1114, S-3007, S-3755, and S-4159) (South Midway Sunset Hoyt Field) NW Section 7, T11N, R23W. 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

The new heater treater will be used for oil water separation.

In order to comply with District Rule 4320 NOx requirements, the applicant is proposing emissions limits of 9 ppmv NOx @ 3% O_2.and 50 ppmv @3% O_2 CO. The unit is equipped with two separate 5.0 MMBtu/hr burners. Natural gas with a sulfur content not exceeding 1.0 gr S/100 scf is proposed as fuel.

The new heater treater will be served by an existing vapor control system S-4159-7 with a vapor control effciency of at least 95% by permit condition.The gas from S-4159-7 is treated to remove sulfur prior to incineration in the 10.4 MMBtu/hr flare listed on S-4159-7.

V. EQUIPMENT LISTING

Pre-Project Equipment Description:

S-4159-7-2: THERMALLY ENHANCED OIL RECOVERY OPERATION SERVING 40 STEAM ENHANCED WELLS WITH OPEN CASING VENTS SERVED BY VAPOR CONTROL SYSTEM INCLUDING COMPRESSOR(S), GAS/LIQUID SEPARATOR, AND 10.4 MMBTU/HR FLARE

Proposed Modification:

S-4159-7-3: MODIFICATION OF THERMALLY ENHANCED OIL RECOVERY OPERATION SERVING 40 STEAM ENHANCED WELLS WITH OPEN CASING VENTS SERVED BY VAPOR CONTROL SYSTEM INCLUDING COMPRESSOR(S), GAS/LIQUID SEPARATOR, AND 10.4 MMBTU/HR FLARE: CONNECT HEATER TREATER S-4159-10 TO VAPOR CONTROL SYSTEM

Post Project Equipment Description:

S-4159-7-3: THERMALLY ENHANCED OIL RECOVERY OPERATION SERVING 40 STEAM ENHANCED WELLS WITH OPEN CASING VENTS SERVED BY

VAPOR CONTROL SYSTEM INCLUDING COMPRESSOR(S), GAS/LIQUID SEPARATOR, AND 10.4 MMBTU/HR FLARE

S-4159-10-0: 10 MMBTU/HR NATURAL GAS-FIRED HEATER TREATER WITH TWO SEPARATE 5.0 MMBTU/HR LOW NOX BURNERS

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

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

Manufacturer's information on the low NOx burner is provided in **Attachment I**.

Sulfur Control

The ATC requires that gas combusted contain no more than 1 gr S/100 scf.

VII. GENERAL CALCULATIONS

A. Assumptions

The maximum operating schedule is 24 hours per day.

Annual pre-project and post-project potential to emit are calculated based on 8760 hours of operation per year.

Process gas expected to contain less than 10% VOCs by wt. Therefore, according to District policy SSP 2015, fugitive emissions are not assessed.

Modifying the vapor control system to connect a new tank to the system is not a NSR modification; therefore, tank S-1114-7 is not being modified and does not require calculations. PE2 will be calculated for inclusion in PAS. There is no change in emissions with connection of the heater treaer and Wemco tank of the vapor control system.

Component counts and fugitve emissions for Heater Treater ('-10) for HRA

Component Type	Emissions Factor lb/day-component*	Number	Lb/day	Lb/yr
Valve	0.2381	11	2.62	956
Others	0.4656	0	0	0
Connectors	0.01058	0	0	0
Flanges	0.02604	24	0.625	228
total			3.2	1,184

*EPA Protocol Equipment Leak Emissions Factors, Table 2-4, EPA-453/R-95-017, November 1995, TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (lb/day/source)

B. Emission Factors

Post-Project Emission Factors (EF2)

For this unit, post-project emission factors are listed in the table below.

Flare for S-4159-7 (current PTO)

Pollutant	Emission Factor (lb/MMBtu)	Source
NOx	0.068	AP-42/FYI-83
SOx	0.0076*	45 ppmv H_2S, 2.66 gr S/100 scf Current PTO
PM10	0.008	AP-42/FYI-83-BACT
CO	0.37	AP-42/FYI-83
VOC	0.063	AP-42/FYI-83

*45 ft^3 H2S/10^6 ft^3 gas x lbmol H2S/379 ft^3 H_2S x 34 lb H2S/lbmol H2S x 32 lbS/34 lb H_2S x 7000 gr S/lb S x 100 = 2.66 gr S/100scf

S-4159-10

Pollutant	Emission Factor (lb/MMBtu)	Source
NOx	0.011	9 ppmv @ 3% O2 BACT
SOx	0.00285	District Std for natiural gas
PM10	0.0070	proposed
CO	0.037	50 ppmv @ 3% O2 proposed
VOC	0.0020	proposed

C. Calculations

1. Pre-Project Potential to Emit (PE1)

S-4159-10

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

2. Post-Project Potential to Emit (PE2)

The PE2 for each pollutant is calculated with the following equation:

- PE2 = EF (lb/MMBtu) × Heat Input (MMBtu/hr) × Op. Sched. (hr/day or hr/year)

S-4159-7

Pollutant	Daily Post-Project Potential to Emit (PE2)									
	Emission Factors			Heat input			Hours per day		Daily PE2	
NO_X	0.0680	(lb-NO_X/MMBtu)	x	10	(MMBtu/hr)	x	24 (hr/day)	=	16.3	(lb-NO_X/day)
SO_X	0.00760	(lb-SO_X/MMBtu)	x	10	(MMBtu/hr)	x	24 (hr/day)	=	1.8	(lb-SO_X/day)
PM_{10}	0.0080	(lb-PM_{10}/MMBtu)	x	10	(MMBtu/hr)	x	24 (hr/day)	=	1.9	(lb-PM_{10}/day)
CO	0.3700	(lb-CO/MMBtu)	x	10	(MMBtu/hr)	x	24 (hr/day)	=	88.8	(lb-CO/day)
VOC	0.0630	(lb-VOC/MMBtu)	x	10	(MMBtu/hr)	x	24 (hr/day)	=	15.1	(lb-VOC/day)

Pollutant	Annual Post-Project Potential to Emit (PE2)						
	Emission Factors		Annual Max Heat input			Annual PE2	
NO_X	0.0680	(lb-NO_X/MMBtu)	x 91.25	(billion Btu/year)	=	6,205	(lb-NO_X/year)
SO_X	0.00760	(lb-SO_X/MMBtu)	x 91.25	(billion Btu/year)	=	694	(lb-SO_X/year)
PM_{10}	0.0080	(lb-PM_{10}/MMBtu)	x 91.25	(billion Btu/year)	=	730	(lb-PM_{10}/year)
CO	0.3700	(lb-CO/MMBtu)	x 91.25	(billion Btu/year)	=	33,763	(lb-CO/year)
VOC	0.0630	(lb-VOC/MMBtu)	x 91.25	(billion Btu/year)	=	5,749	(lb-VOC/year)

Fugitive emissions: 1.9 lb/day, 694 lb/yr

PE2		
Pollutant	**Daily Emissions (lb/day)**	**Annual Emissions (lb/year)**
NO_X	16.3	6,205
SO_X	1.8	694
PM_{10}	1.9	730
CO	88.8	33,763
VOC	15.1 + 1.9 = 17.0	5,749 + 694 = 6,443

S-4159-10

Pollutant	**Daily PE2**			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/day)	Daily PE2 (lb/day)
NO_X*	0.011	10	24	2.6
SO_X	0.00285	10	24	0.7
PM_{10}	0.0070	10	24	1.7
CO	0.037	10	24	8.9
VOC	0.0020	10	24	0.5

Pollutant	**Annual PE2**			
	EF2 (lb/MMBtu)	Heat Input (MMBtu/hr)	Operating Schedule (hr/year)	Annual PE2 (lb/year)
NO_X	0.011	10	8,760	964
SO_X	0.00285	10	8,760	250
PM_{10}	0.0070	10	8,760	613
CO	0.037	10	8,760	3,241
VOC	0.0020	10	8,760	175

Fugitve emissions:

VOCs: 0 lb/day, 0 lb/yr (< 10% VOCs by wt in vapor)

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

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	NO_X	SO_X	PM_{10}	CO	VOC
SSPE Calculator	94,069	382,659	121,782	121,782	170,095
ATC S-1114-125-1	4,617	2122	5659	13,775	3999
ATC S-1114-133-0	472	124	300	1587	86
ATC S-1114-134-0	1,156	305	736	3889	210
ATC S-1114-136-0	4,542	2122	5659	13,775	3999
ATCs S-3007-21 thru '23	0	0	0	0	312
SSPE1*	108,856	387,332	134,136	154,808	178,701

*includes ATCs with significant emissions increases, does not include ERCs
There are no outstanding ATCs for S-3755, and S-4159, The facility has no CO ERCs.

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.

SSPE2 (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
SSPE1	108,856	387,332	134,136	154,808	178,701
S-4159-10-0	964	250	613	3,241	175
SSPE2	109,820	387,582	134,749	158,049	178,876

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}	CO	VOC
Facility emissions pre-project	108,856	387,332	134,136	154,808	178,701
Facility emissions – post project	109,820	387,582	134,749	158,049	178,876
Major Source Threshold	20,000	140,000	140,000	200,000	20,000
Major Source?	yes	yes	no	no	yes

As seen in the table above, the facility is an existing Major Source for NOx, CO, and VOC and is not becoming a Major Source for SOx and PM_{10} as a result of this project.

<u>Rule 2410 Major Source Determination:</u>

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). Therefore, the following PSD Major Source thresholds are applicable.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	**VOC**	**SO_2**	**CO**	**PM**	**PM_{10}**
Estimated Facility PE before Project Increase	54	89	194	77	67	67*
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lbs/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.

S-4159-10-0:

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 or PM10, this project does not constitute an SB 288 major modification for these air contaminants.

Since this facility is a major source for NOx, SOx, and VOCs, 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	964	50,000	No
SO_x	250	80,000	No
VOC	0*	50,000	No

*increases of less than 0.5 lb/day (annual emissions/ 365) round to zero for NSR purposes.

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.

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

Federal Major Modification Thresholds for Emission Increases			
Pollutant	Total Emissions Increases (lb/yr)	Thresholds (lb/yr)	Federal Major Modification?
NO_x	964*	0	Yes
VOC	0 (0.5 lb/day ~ 0)**	0	No
PM_{10}	613	30,000	No
$PM_{2.5}$	613	20,000	No
SO_x	250	80,000	No

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

**increases of less than 0.5 lb/day (annual emissions/365) round to zero for NSR purposes.

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-4159-10	**0**	**964**	**964**
		Net Emission Change (lb/year):	**964**
		Federal Offset Quantity: (NEC * 1.5)	**1,446**

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 Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	0.5	0	0.125	1.6	0.3	0.3
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis 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. The permit units are new and therefore 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 heater treater with a PE greater than 2 lb/day for NO_x and CO. BACT is triggered for NO_x only (for the heater treater) since the PE is greater than 2 lb/day. However, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lb/year, as demonstrated in Section VII.C.5 above.

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 constitute an Federal Major Modification for NO_x emissions. Therefore, BACT is triggered for NO_x for all emissions units in the project for which there is an emission increase (heater treater).

2. BACT Guideline

Please note that BACT Guidelines 1.8.4 Heater Treater < 20 MMBtu/hr, natural gas-fired and 1.8.5 [Process Heater (non-refinery, < or = 20 MMBtu/hr] have been rescinded and are replaced by the District Rule 4320 requirements for NOx.

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 III**), BACT has been satisfied with the following:

NO_X: 9 ppmvd @ 3% O_2

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals 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	109,820	387,582	134,749	158,049	178,876
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	Yes	Yes	Yes	No	Yes

2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for NO_X only. Therefore offset calculations will be required for this project.

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 = 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 = HAE

The facility is proposing to install a new emissions unit heater treater; therefore BE = 0. Also, there is only one emissions unit associated with this project and there are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

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

The project is a Federal Major Modification and therefore the correct offset ratio (DOR) for NO_x and VOCs is 1.5:1.

<u>NOx</u>

Assuming an offset ratio of 1.5:1, the amount of NO_x ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([964 – 0] + 0) x 1.5
= 964 x 1.5
= 1,446 lb NOx/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly offsets required (lb/qtr) = (1446 lb NOx/year) ÷ (4 quarters/year)
= 361.5 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
361	361	362	362	1,446

The applicant has stated that the facility plans to use ERC certificate S-4821-2 to offset the increases in NO_x emissions associated with this project. The above certificate has available quarterly NO_x credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-4821-2	735	735	734	735

As seen above, the facility has sufficient credits to fully offset the quarterly NO_x emissions increases associated with this project.

SOx

Assuming an offset ratio of 1.5:1 (site of reduction > 15 miles from S-4159), the amount of SO_x ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([250 – 0] + 0) x 1.5
= 250 x 1.5
= 375 lb SO_x/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly offsets required (lb/qtr) = (375 lb SO_x/year) ÷ (4 quarters/year)
= 93.75 lb/qtr

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

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total Annual
93	94	94	94	375

The applicant has stated that the facility plans to use ERC certificate S-4824-5 to offset the increases in SO_x emissions associated with this project. The above certificate has available quarterly SO_x credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #S-4824-5	194	194	194	193

As seen above, the facility has sufficient credits to fully offset the quarterly SO_x emissions increases associated with this project.

PM10

Assuming an offset ratio of 1.5:1 (site of reduction > 15 miles from S-4159), the amount of SO_x ERCs that need to be withdrawn is:

Offsets Required (lb/year) = ([613 – 0] + 0) x 1.5
= 613 x 1.5
= 920 lb PM10/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly offsets required (lb/qtr) = (920 lb PM10/year) ÷ (4 quarters/year)
= 230 lb/qtr

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

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total Annual
230	230	230	230	920

The applicant has stated that the facility plans to use ERC certificate N-1409-4 to offset the increases in PM10 emissions associated with this project. The above certificate has available quarterly PM10 credits as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #N-1409-4*	0	0	468	1403

*Rule 2201 Section 4.13.7 AER for PM that occurred from October through March, inclusive, may be used to offset increases in PM during any period of the year.

As seen above, the facility has sufficient credits to fully offset the quarterly PM10 emissions increases associated with this project.

VOC

The heater treater VOC emissions are 0.5 lb/day. Pursuant to District Policy APR 1130

"a total project annual emission increase (Σ [PE2 – PE1] for all units in the project) that *averages* less than or equal to 0.5 lb/day is rounded to zero (0) lb/day, only for the purposes of determining whether New and Modified Source Review (NSR) rule requirements are triggered."

Therefore, offsets are not required for VOCs.

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 - 361 lb, 2nd quarter - 361 lb, 3rd quarter - 362 lb, and fourth quarter - 362 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]

- ERC Certificate Number S-4821-2 (or a certificate split from this certificate) 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]

- {GC# 4447 - edited} Prior to operating equipment under this Authority to Construct, permittee shall surrender SOx emission reduction credits for the following quantity of emissions: 1st quarter - 93 lb, 2nd quarter - 94 lb, 3rd quarter - 94 lb, and fourth quarter - 94 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]

- ERC Certificate Number S-4824-5 (or a certificate split from this certificate) 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]

- {GC# 4447 - edited} Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 230 lb, 2nd quarter - 230 lb, 3rd quarter - 230 lb, and fourth quarter - 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]

- ERC Certificate Number S-1409-4 (or a certificate split from this certificate) 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]

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,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
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 an SB 288 or Federal Major Modification. Therefore, public noticing for SB 288 or Federal Major Modification purposes is required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not 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	108,856	109,820	20,000 lb/year	No
SO_X	387,332	387,582	54,750 lb/year	No
PM_{10}	134,136	134,749	29,200 lb/year	No
CO	154,808	158,049	200,000 lb/year	No
VOC	178,701	178,876	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not 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	109,820	108,856	964	20,000 lb/year	No
SO_x	387,582	387,332	250	20,000 lb/year	No
PM_{10}	134,749	134,136	613	20,000 lb/year	No
CO	158,049	154,808	3,241	20,000 lb/year	No
VOC	178,876	178,701	175	20,000 lb/year	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not 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 Permit Modification is required for this project.

2. Public Notice Action

As discussed above, public noticing is required for this project which is a Title V Significant Modification. 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.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions:

S-4159-10 (Heater Treater)

Emissions from the natural gas-fired unit shall not exceed any of the following limits: 9 ppmvd NOx @ 3% O2 or 0.011 lb-NOx/MMBtu, 0.00285 lb SOX/MMBtu, 0.007 lb-PM10/MMBtu, 50 ppmvd CO @ 3% O2 or 0.037 lb-CO/MMBtu, or 0.002 lb-VOC/MMBtu. [District Rules 2201, 4201, 4301, 4305, 4306, 4320, and 4801]

The unit shall only be fired on gas with a maximum sulfur content of 1.0 gr S/100scf. [District Rules 2201 and 4320] Y

E. Compliance Assurance

1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

2. Monitoring

<u>S-1114-140 & 141</u>

The VOC content of the gas shall not exceed 10% by weight. [District Rule 2201] Y

Operator shall conduct quarterly gas sampling for gas exiting the separator pressure vessel to qualify for exemption from fugitive component counts for components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201] Y

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:

The permittee shall keep accurate records of the date VOC sampling occurred, who performed the sampling and testing, and the results. [District Rule 2520] Y

All monitoring data, support information and records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rules 1070, 4305, 4306, and 4320] Y

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to **Attachment IV** of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

G. Compliance Certification

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 Section VIII above, this facility is a new major source and this project does constitute a Federal Major Modification, therefore this requirement is applicable. Seneca's compliance certification is included in **Attachment V**.

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to install a heater treater and Wemco. Since the project will provide new equipment 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 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Pursuant to their current operating permit, this facility is an existing major source; however, the facility has not received their Title V permit. An application to comply with Rule 2520 - *Federally Mandated Operating Permits* has already been submitted to the District. Therefore, no action is required at this time.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60. 40 CFR Part 60, Subpart Dc applies to Small Industrial-Commercial-Industrial Process heaters between 10 MMBtu/hr and 100 MMBtu/hr.

This heater treater has a rating of 10 MMBtu/hr and is fired on natural gas. Subpart Dc has no standards for gas-fired steam generators. Therefore, testing and monitoring requirements of subpart Dc do not apply.

Subpart Dc, subpart 60.48c requires the owner or operator of each affected facility to submit notification of the date of construction or reconstruction, anticipated startup, actual startup, as provided by Subpart A §60.7 of this part. Notification shall include

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

The designed heat input capacity and the identified fuels will be listed on the equipment description. No other permit conditions are required.

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

The above requirement is not applicable since the unit is not subject to §60.42c or §60.43c.

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

The facility has not proposed an annual capacity factor and one will not be imposed on the facility.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c (a) or (b)1, unless the unit determination is made by the Administrator.

Section 60.48c(g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

Since the unit has been evaluated assuming that it will consume the maximum amount of fuel allowed by the unit each day, the facility will not be required to record the daily fuel consumption.

Section 60.48c(i) states that all records required under this section shall be maintained by the owner operator of the affected facility for a period of two years following the date of such record. The ATCs require that records be kept for 5 years.

The following condition is included on the S-4159-10 ATC:

Permittee shall comply with all applicable testing, recordkeeping, and reporting requirements specified in Rule 4001 - New Source Performance Standards, including but not limited to Subparts A and Ja. [District Rule 4001] Y

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). As the steam generator is fired solely on natural gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. The following condition will be listed on the steam generator permit to ensure compliance:

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]

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. This facility wide permit for BPC contains the following condition:

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

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District 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 IV**), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The exhaust stacks 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
PM10 Emission Factor:	0.0076 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust:	100%
Exhaust Oxygen (O_2) Concentration:	3%
Excess Air Correction to F Factor =	20.9/(20.9 - 3) = 1.17

$$GL = \left(\frac{0.007\ lb-PM}{MMBtu}\right) * \left(\frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} * 1.17\right)$$

$$GL = 0.005\ grain/dscf < 0.1 grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected. Additionally, particulate matter emissions from the steam generator is already limited by Rule 2201 to a value less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions. Therefore the following condition, previously discussed, will ensure compliance with this rule:

Emission rates shall not exceed: NOx (as NOx): 9 ppmvd @ 3% O2 or 0.011 lb-NOx/MMBtu PM10: 0.007 lb/MMBtu; CO: 50 ppmvd @ 3% O2 or 0.037 lb-CO/MMBtu; or VOC: 0.002 lb/MMBtu. [District Rule 2201, 4305, 4306, and 4320] Y

Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter.

District Rule 4301 Limits (lb/hr)			
Pollutant	NO_2	Total PM	SO_2
S-4159-10	0.011 x 10 = 0.11	0.007x 10 0.07	0.00285 x 10 = 0.03
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule;

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

This rule provides equipment tuning procedures for boilers, steam generators and process heaters to control visible emissions and emissions of both nitrogen oxides (NOx) and carbon monoxide (CO).

This unit will follow District approved Alternate Monitoring scheme A, where the applicable emission limits are periodically monitored for compliance with Rule 4320 and is not required to perform tuning in accordance with the procedures of this Rule.

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

This unit is natural gas-fired with a maximum heat input of 10 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 the emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy the requirements of District Rule 4305.

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

This unit is natural gas-fired with a maximum heat input of 10 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

In addition, the unit is also subject to *District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5 MMBtu/hr.*

Since the 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 the requirements of District Rule 4306.

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

Section 5.2 NOx and CO Emission Limits

The 10 MMBtu/hr process heater is subject to the following NOx limits in Table 2, as shown below.

The applicant has proposed to meet the standard schedule NOx emission limit.

Rule 4320 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_x Limit	CO Limit	NO_x Limit	CO Limit
A. Units with a total rated heat input > 5.0 MMBtu/hr to < 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu			

The proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.074 lb/MMBtu).

Therefore, compliance with 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 of the rule requires one of four options for control of particulate matter: 1) combustion of 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 (5) grains of total sulfur per one hundred (100) standard cubic, 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% O2 or 4) refinery units, which require modification of refinery equipment to reduce sulfur emissions, shall be in compliance with the applicable requirement in Section 5.4.1 no later than July 1, 2013.

The heater treater will only combust natural gas containing no more than 1 gr S/100 scf.

Section 5.6, Startup and Shutdown Provisions

Applicable emissions limits are not required during startup and shutdown provided The duration of each start-up or each shutdown shall not exceed two hours, the emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown or operator has submitted an application for a Permit to Operate condition to allow more than two hours for each start-up or each shutdown provided the operator meets all of the conditions specified in Sections 5.6.3.1 through 5.6.3.3.

Startup and shutdown conditions have not been proposed.

Section 5.7, Monitoring Provisions

Section 5.7 requires either use of a APCO approved Continuous Emissions Monitoring System (CEMS) for NOx, CO, and oxygen, or implementation of an APCO-approved Alternate Monitoring System.

In order to satisfy the requirements of District Rule 4320, the applicant has proposed to use pre-approved alternate monitoring scheme A (pursuant to District Policy SSP-1105), which requires that monitoring of NOx, CO, and O_2 exhaust concentrations shall be conducted at least once per month (in which a source test is not performed) using a portable analyzer. The following conditions will be incorporated into the permit in order to ensure compliance with the requirements of the proposed alternate monitoring plan:

{4063} 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 analyzer 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, 4306, and 4320]

{4064} 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 the performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

{4065} 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, 4306, and 4320]

{4066} The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent by volume 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, 4306, and 4320]

5.7.6 Monitoring SOx Emissions

Section 5.7.6.1 Operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit To Operate. Sulfur analysis shall be performed in accordance with the test methods in Section 6.2.

Section 5.7.6.2 Operators complying with Section 5.4.1.3 by installing and operating a control device with 95% SOx reduction shall propose the key system operating parameters and frequency of the monitoring and recording. The monitoring option proposed shall be submitted for approval by the APCO.

Section 5.7.6.3 Operators complying with Section 5.4.1.3 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit To Operate. Source tests shall be performed in accordance with the test methods in Section 6.2.

Heater treater shall only be fired on PUC-regulated natural gas with a sulfur content not exceeding 1.0 gr S/100 scf. [District Rule 2201] Y

Valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts may be used to satisfy the fuel sulfur content analysis, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 4320] N

Section 5.8 Compliance Determination

Section 5.8.1 requires that the operator of any unit have the option of complying with either the applicable heat input (lb/MMBtu), emission limits or the concentration (ppmv) emission 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). Therefore, the following condition will be retained or listed on the permits as follows:

{2976} The source 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 requires 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. Therefore, the following permit condition will be listed on the permits as follows:

{2972} 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. For the purposes of permittee-performed alternate monitoring, emissions

measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

Section 5.8.4 requires that for emissions monitoring pursuant to Sections 5.7.1 and 6.3.1 using a portable NOx analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following previously listed permit condition will be on the permits as follows:

{2937} 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, 4306 and 4320]

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

{2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

Section 6.1 Recordkeeping

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 and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. Therefore, the following permit condition will be listed on the permit as follows:

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, 4306, 4320 and 40 CFR 60.48c(i)]

Section 6.2, Test Methods

Section 6.2 identifies test methods to be used when determining compliance with the rule. The following conditions will be listed on the permits:

{109} 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]

The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; Stack gas oxygen (O2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities – EPA Method 2; Stack gas moisture content – EPA Method 4; SOx – EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H2S content – EPA Method 11 or 15; and fuel hhv (MMBtu) – ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rules 4305, 4306 and 4320]

Section 6.3, Compliance Testing

Section 6.3.1 requires that each unit subject to the requirements in Section 5.2 shall be source tested at least once every 12 months, except if two consecutive annual source tests demonstrate compliance, source testing may be performed every 36 months. If such a source test demonstrates non-compliance, source testing shall revert to every 12 months. The following conditions will be included in the permits:

A source test to demonstrate compliance with NOx and CO emission limits shall be performed within 60 days of startup of this unit. [District Rules 2201 and 4320]

Source testing to measure natural gas-combustion NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). 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 2201, 4305, 4306 and 4320]

{110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Sections 6.3.2.1 through 6.3.2.7 address the requirements of group testing which is not proposed in this project. Therefore these sections are not applicable.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permits. Therefore, compliance with District Rule 4320 requirements is expected.

District 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 10 MMBtu/hr heater treater will be fired on natural gas containing no more than 1 gr S/100 scf and therefore compliance is expected.

Therefore, compliance with District Rule 4801 requirements is expected.

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.

Greenhouse Gas (GHG) Significance Determination

<u>District is a Responsible Agency</u>

Oil and gas operations in Kern County must comply with the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting.* In 2015, Kern County revised the Kern County Zoning Ordinance Focused on Oil and Gas Activities (Kern Oil and Gas Zoning Ordinance) in regards to future oil and gas exploration, and drilling and production of hydrocarbon resource projects occurring within Kern County.

Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The EIR evaluated and disclosed to the public the environmental impacts associated with the growth of oil and gas exploration in Kern County, and determined that such growth will result in significant GHG impacts in the San Joaquin Valley. As such, the EIR included mitigation measures for GHG.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating GHGs. The District has determined that the applicant is responsible for implementing GHG mitigation measures imposed in the EIR by the Kern County for the Kern County Zoning Ordinance.

District CEQA Findings

The proposed project is located in Kern County and is thus subject to the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting.* The *Kern County Zoning Ordinance* was developed by the Kern County Planning Agency as a comprehensive set of goals, objectives, policies, and standards to guide development, expansion, and operation of oil and gas exploration within Kern County.

In 2015, Kern County revised their *Kern County Zoning Ordinance* in regards to exploration, drilling and production of hydrocarbon resources projects. Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The revised Kern County Zoning Ordinance establishes a written process (Conformity Review permit process or Minor Activity permit) by which oil and gas exploration projects involving site-specific operations can be evaluated to determine whether the environmental effects of the operation were covered in the *Kern County Zoning Ordinance* EIR.

For stationary source emissions that are below the offset threshold, i.e. not required to surrender ERCs, and for non-stationary source emissions, Kern County entered into an Oil and Gas Emission Reduction Agreement (Oil and Gas ERA) with the District pursuant to the EIR. Per the Oil and Gas ERA, the applicant shall fully mitigate project emissions that are not required to be offset by District permit rules and regulations. Such mitigation can be achieved through any of the three options: (1) the applicants pay an air quality mitigation fee with each Oil and Gas Conformity Review permit issued by the Kern County, (2) the applicants may develop and propose to implement their own emission reduction projects instead of paying all or part of the mitigation fee, or (3) the applicants will be allowed to enter into an agreement directly with the District (if approved by Kern County) to develop an alternative fee schedule.

Kern County, as the lead agency, is the agency that will enforce the mitigation measures identified the EIR, including the mitigation requirements of the Oil and Gas ERA. As a responsible agency the District complies with CEQA by considering the EIR prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project involved (CCR §15096). The District has reviewed the EIR prepared by Kern County, the Lead Agency for the project, and finds it to be adequate. To reduce project related impacts on air quality, the District evaluates emission controls for the project such as Best Available Control Technology (BACT) under District Rule 2201 (New and Modified Stationary Source Review). In addition, the District is requiring the applicant to surrender emission reduction credits (ERC) for stationary source emissions above the offset threshold.

Thus, the District concludes that through a combination of project design elements, permit conditions, and the Oil and Gas ERA, the project will be fully mitigated to result in no net increase in emissions. Pursuant to CCR §15096, prior to project approval and issuance of ATCs the District prepared findings.

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The revision to the *Kern County Zoning Ordinance* went through an extensive public process that included a Notice of Preparation, a preparation of an EIR, scoping meetings, and public hearings. The process led to the certification of the final EIR and approval of the revised *Kern County Zoning Ordinance* in November 2015 by the Kern County Board of Supervisors. As mentioned above, the proposed project will be fully mitigated and will result in no net increase in emissions. In addition, the proposed project is not located at a facility of concern; therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. RECOMMENDATION

Compliance with all applicable rules and regulations is expected. Pending a successful EPA/COC review period, issue Authority to Construct S-4159-10-0 subject to the permit conditions on the attached draft Authorities to Construct in **Attachment VI**.

X. BILLING INFORMATION

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
S-4159-10	3020-02-G	10 MMBtu/hr	$ 893.00

Attachments

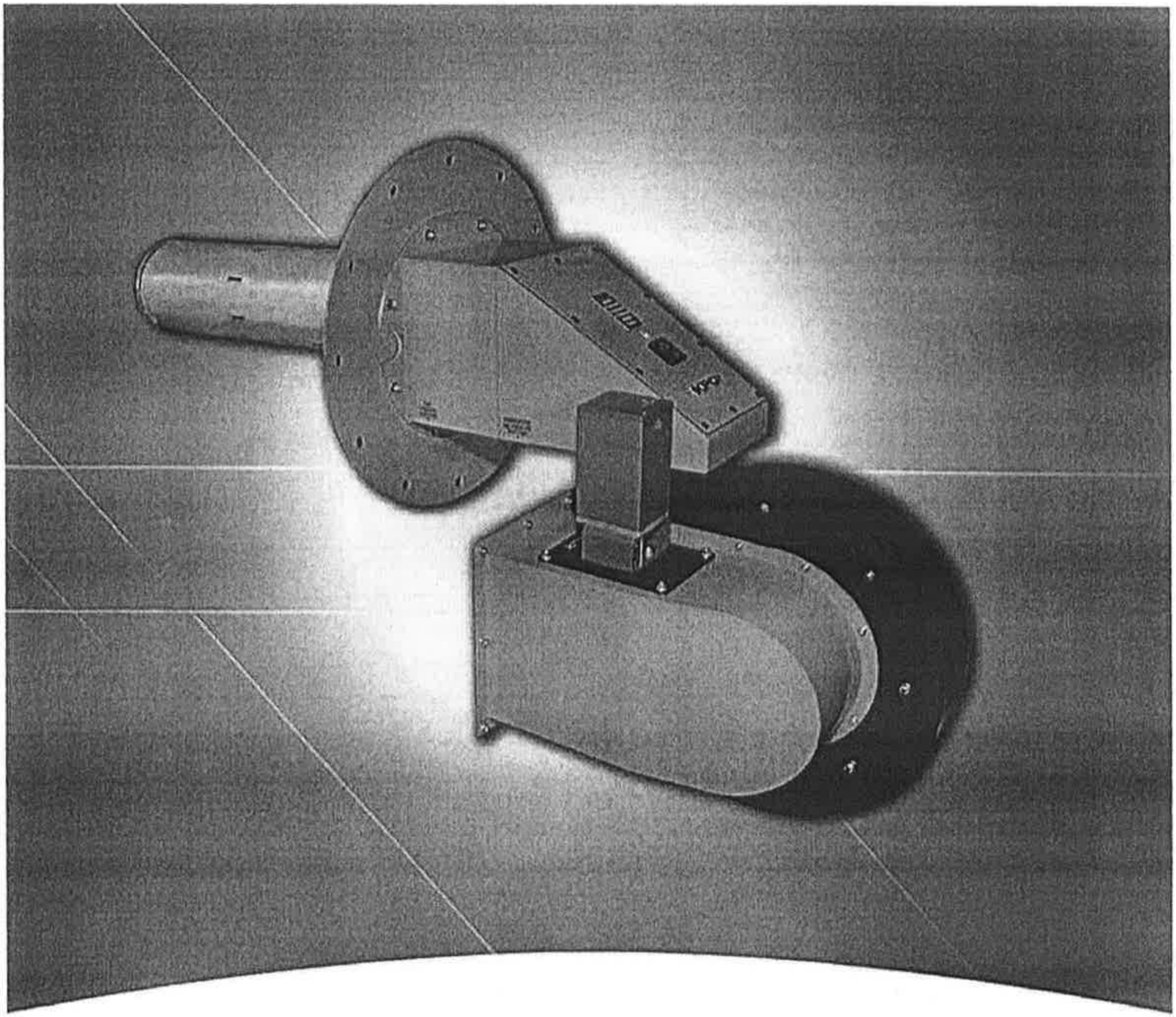
I: Manufacturer Information
II: Emission Profiles
III: BACT Analysis
IV: HRA/AAQA
V: Statewide Compliance Statement
VI: Draft ATC

ATTACHMENT I
Manufacturer Information

MAXON XPO™

Ultra low NOx indirect burner

Honeywell



Technical Catalog

TABLE OF CONTENTS

FEATURES & BENEFITS

- Low temperature burner for use with clean fuel gases
- Single digit NOx emissions at 30% excess air
- High efficiency with low excess air requirements
- Capacities up to 2340 kW with a least 3:1 turndown ratio
- For use in indirect fired solution backed heaters

PRODUCT DESCRIPTION

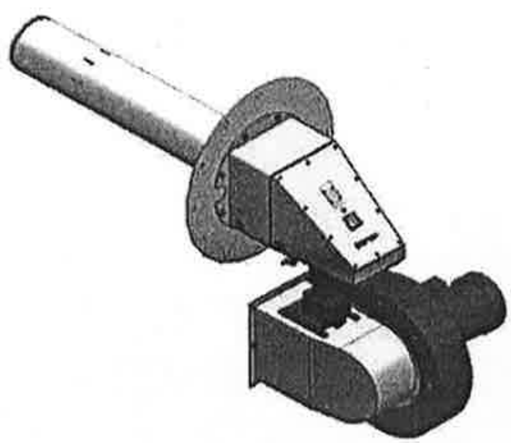
Maxon XPO™ burners are low temperature burners for use in liquid backed applications. They provide high efficiency operation with low excess air requirements and are designed for ease of retrofitting into existing liquid backed applications.

XPO™ burners are available in two basic versions:

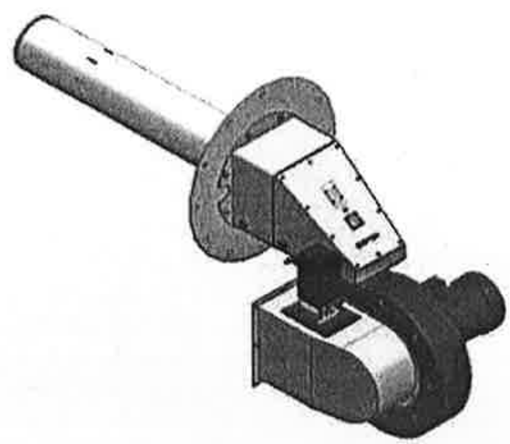
- Packaged (PB) with integral combustion air blower
- External blower (EB) for use with an external combustion air source for extended capacities

Both packaged (PB) and external blower (EB) versions include two different choices for blast tube lengths. A 610 mm or 1220 mm long blast tube is available. Blast tube length should be selected based on the wall penetration depth or non-liquid cooled portion of fire tube.

The packaged (PB) version also includes a choice of blower voltage and a choice of air/fuel ratio control actuators. MAXON requires the use of parallel positioning control systems. For indoor, general purpose installations, use Honeywell ControLink™ or equivalent system. For outdoor or hazardous duty service installations, use MAXON SMARTLINK® MRV control systems.



XPO™ burner with
Honeywell ControLink™



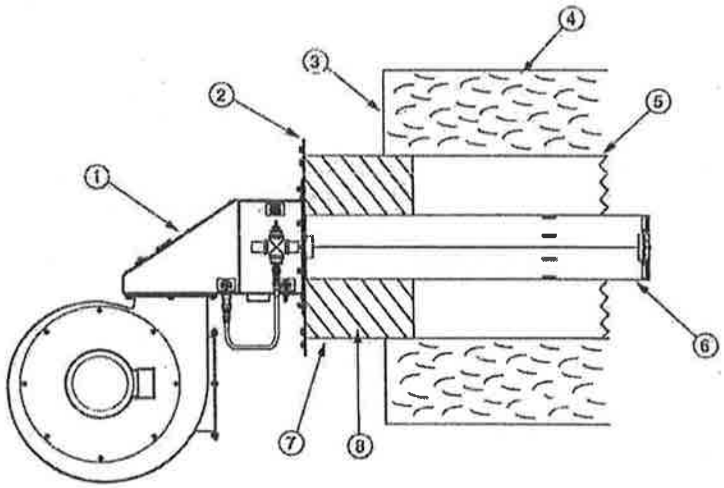
XPO™ burner with
MAXON SMARTLINK®

TYPICAL APPLICATIONS

MAXON XPO™ burners are low temperature burners for use in liquid backed applications, including:

- Water back heater
- Fire tube boiler
- Thermal oil heater
- Direct contact water heater
- Solution heating/tanks
- Snow melters

1) XPO™ burner
2) Mounting flange
3) Unit wall
4) Liquid solution
5) Fire tube
6) Burner blast tube
7) Non-cooled fire tube wall
8) Customer-supplied insulation*



*All non-liquid cooled surfaces **must be insulated** as shown above.

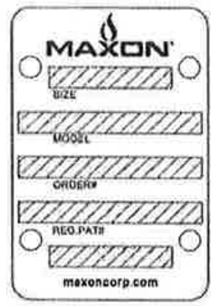
TYPICAL EMISSIONS

XPO™ burner will achieve ultra low NOx emissions while operating at 30% excess air level.

Exact emissions performance may vary in your application. Contact MAXON for information on installation specific estimates or guarantees. No guarantee of emissions is intended or implied without specific written guarantee from MAXON.

INTELLIGENT MODEL NUMBERS

A coded model number is provided on the nameplate of all XPO™ burners to provide a simple method to identify the configuration of the product. This model number ensures accuracy in identifying your product, ordering replacement parts or communicating capabilities.



Burner series	Size	Blower options	Blast tube length	Voltage	Control method	Flame detection	Air pressure switch	Actuator	Mounting flange gasket	Air valve position	Air actuator position
XPO	1	PB	2	1	B	3	N	Y	Y	L	T

Burner series
XPO

Size
1 = Blast tube #1
2 = Blast tube #2
3 = Blast tube #3
4 = Blast tube #4
5 = Blast tube #5

Blower options
PB = packaged burner (blower included)
EB = external blower (blower not included)

Blast tube length
2 = 610 mm
4 = 1220 mm [3]

Voltage
1 = 230/460/3/60
2 = 575/3/60 [2]
3 = 115/230/1/60 [1]
* = for external blowers (N/A)

Control method
B = SMARTLINK MRV
C = Honeywell ControLink
* = for external blowers

Flame detection
3 = Standard UV scanner provision
4 = Hazardous location UV scanner provision

Air pressure switch
A = Antunes
H = Honeywell
N = None

Actuator
Y = Included with burner
N = Not included
* = external blowers

Mounting flange gasket
Y = included with burner
N = not included

Air valve position
L = Left hand
R = Right hand

Air actuator position
B = Bottom of air valve
T = Top of air valve

[1] Only choice available for size #1, #2 and #3 blast tubes
[2] Only available in size #1
[3] Only choice available for size #4 and #5 blast tubes

SPECIFICATIONS OF XPO™ ULTRA LOW NOX BURNERS

Packaged versions (PB)

Typical burner data Fuel: natural gas at 15°C with 10.9 kWh/Nm³ HHV - sg = 0.6 [1] Combustion air: 15°C - 21% O_2 - 50% humidity - sg = 1.0 [1] Stated pressures are indicative. Actual pressures are a function of air humidity, altitude, type of fuel and gas quality.											
		XPO 1 PB 2 XPO 1 PB 4		XPO 2 PB 2 XPO 2 PB 4		XPO 3 PB 2 XPO 3 PB 4		XPO 4 PB 4		XPO 5 PB 4	
		15% excess air	30% excess air	15% excess air	30% excess air	15% excess air	30% excess air	15% excess air	30% excess air	15% excess air	30% excess air
Maximum burner capacity [4]	kW	351	293	688	615	966	878	1464	1318	1932	1757
Minimum burner capacity [2]	kW	88	88	173	173	193	193	293	293	293	293
Turndown ratio [3]		4:1	3.3:1	4:1	3.6:1	5:1	4.5:1	5:1	4.5:1	6.6:1	6:1
Maximum air flow	m³/h	374	352	732	739	1028	1055	1558	1582	2042	2098
Advised pilot capacity	kW	17	17	23	23	29	29	29	29	29	29
Advised pilot pressure [6]	mbar	5	5	10	10	15	15	22	22	22	22
Fan horsepower		1	1	3	3	5	5	7.5	7.5	7.5	7.5
Blast tube OD	mm	152	152	152	152	152	152	203	203	203	203
Air pressure [5] [6]	mbar	22	16	35	35	37	30	40	40	39	39
Air pressure minimum [3] [5]	mbar	1.25 - 2.5	1.25 - 2.5	1.25 - 2.5	1.25 - 2.5	1.25 - 2.5	1.25 - 2.5	1.7	1.7	1.25	1.25
Gas pressure [5] [6]	mbar	22	16	35	34	37	30	40	40	37	36
Fire tube size (inside diameter)	mm	355 to 457		406 to 560		457 to 610		560 to 812		560 to 864	

[1] sg (specific gravity) = relative density to air (density air = 1.293 kg/Nm³)
[2] Minimum burner capacity will be affected by fuel and applications parameters (heat flux).
[3] Will vary depending on the application heat flux. Lower heat flux (<3631 kW/m²) will result with lower turndown ratios and increase in minimum air pressure.
[4] Capacity displayed assumes blower operation on 60Hz electrical supply. Gross output will be reduced by 17% if operated on 50Hz. Fuel and air pressure should be reduced by 30% while motor power will reduce 40% with 50Hz operation. Turndown ratio will be reduced in kind with minimum capacity remaining fixed.
[5] Measured as differential to chamber port.
[6] Measured with scanner cooling air valve closed.

Note: For proper burner adjustment, MAXON advises the use of an oxygen content meter. Optimal oxygen level in the exhaust stack should read between 3 and 6 vol. % dry when measured with burner operating at maximum capacity firing rate.

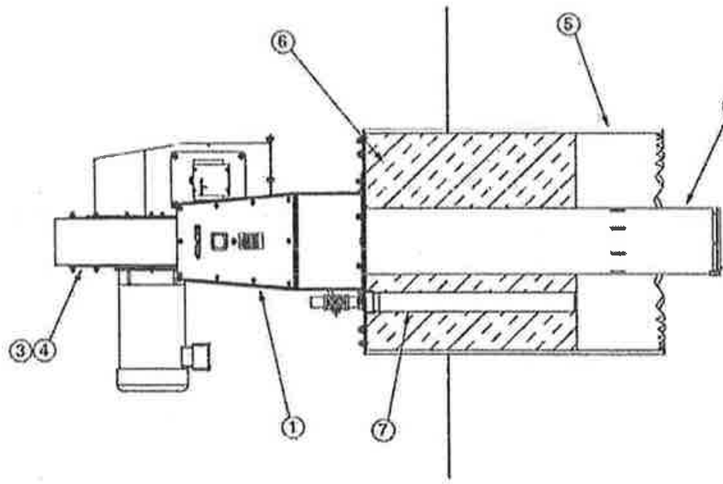
External blower versions (EB)

Typical burner data Fuel: natural gas at 15°C with 10.9 kWh/Nm³ HHV - sg = 0.6 [1] Combustion air: 15°C - 21% O_2 - 50% humidity - sg = 1.0 [1] Stated pressures are indicative. Actual pressures are a function of air humidity, altitude, type of fuel and gas quality.					
		XPO 3 EB 2 XPO 3 EB 4		XPO 5 EB 4	
		15% excess air	30% excess air	15% excess air	30% excess air
Maximum burner capacity [4]	kW	1318	1230	2577	2342
Minimum burner capacity [2]	kW	220	220	439	439
Turndown ratio [3]		6:1	5.6:1	5.9:1	5.3:1
Maximum air flow	m^3/h	1402	1478	2718	2798
Advised pilot capacity	kW	29	29	29	29
Advised pilot pressure [6]	mbar	15	15	20	20
Blast tube OD	mm	152	152	203	203
Air pressure [5] [6]	mbar	80	80	67	67
Air pressure minimum [3] [5]	mbar	1.25 - 2.5	1.25 - 2.5	1.7	1.7
Gas pressure [5] [6]	mbar	90	85	69	68
Fire tube size (inside diameter)	mm	406 to 711		559 to 914	

[1] sg (specific gravity) = relative density to air (density air = 1.293 kg/Nm³)
[2] Minimum burner capacity will be affected by fuel and applications parameters (heat flux).
[3] Will vary depending on the application heat flux. Lower heat flux (<3631 kW/m²) will result with lower turndown ratios and increase in minimum air pressure.
[4] Capacity displayed assumes blower operation on 60Hz electrical supply. Gross output will be reduced by 17% if operated on 50Hz. Fuel and air pressure should be reduced by 30% while motor power will reduce 40% with 50Hz operation. Turndown ratio will be reduced in kind with minimum capacity remaining fixed.
[5] Measured as differential to chamber port.
[6] Measured with scanner cooling air valve closed.

Note: For proper burner adjustment, MAXON advises the use of an oxygen content meter. Optimal oxygen level in the exhaust stack should read between 3 and 6 vol. % dry when measured with burner operating at maximum capacity firing rate.

MATERIALS OF CONSTRUCTION



Item number	Burner part	Material
1	Burner housing	1010 steel (1.1121)
2	Blast tube	304 stainless steel (1.4301)
3	Fan case	1010 steel (1.1121)
4	Fan impeller (inside fan case)	Aluminum
5	Fire tube (customer supplied)	Stainless steel (recommended)
6	Insulation (customer supplied)	Soft insulation material 1090°C temperature rating
7	Guide tube (customer supplied)	Stainless steel (recommended)

SELECTION CRITERIA

Application details

XPO™ burners can be used in all indirect fire tube liquid backed solution heater applications. They combine flexibility and stability with low NOx emissions.

PROCESS TEMPERATURE
The XPO™ burner is engineered for installation in moderate temperature (less than 870°C), liquid backed fire tubes. Protect the burner from high temperatures during a burner stop (purge to avoid back flow of hot process air).

PILOTING AND IGNITION
All XPO™ burners are equipped with an independent pilot design. Pilots shall be used only for ignition of the main flame (interrupted). Use of a standing (continuous) pilot is not recommended. Use minimally 5000 V/200 VA ignition transformers for sparking of the spark ignitor.

Start the burner at low fire setting only. Direct spark ignition of standard XPO™ burners is possible. Locate one pilot gas valve as close as possible to the pilot burner gas inlet to have fast ignition of the pilot burner.

TYPICAL IGNITION SEQUENCE

- Pre-purge of burner and installation, according to the applicable codes and the installation's requirements.
- Combustion air control valve shall be in the minimum position to allow minimum combustion air flow to the burner.
- Pre-ignition (typically 2 seconds sparking in air).
- Open pilot gas and continue to spark the ignitor (typically 5 seconds).
- Stop sparking, continue to power the pilot gas valves and start flame check. Trip burner if no flame from here on.
- Check pilot flame stability (typically 5 seconds to prove stable pilot).
- Open main gas valves and allow enough time to have main gas in the burner (typically 5 seconds + time required to have main gas in the burner).
- Close the pilot gas valves.
- Release to modulation (allow modulation of the burner).

Above sequence shall be completed to include all required safety checks during the start-up of the burner (process and burner safeties).

RATIO CONTROL
Accurate air/fuel ratio control can be accomplished with MAXON SMARTLINK® or Honeywell ControLink™ actuators. Precise ratio control will yield optimal emissions and efficiency performance.

FLAME SUPERVISION
XPO™ burner flames shall be supervised by the use of a UV or IR scanner.

PIPING
Follow all applicable codes including regional codes, local directives, standards and recommendations of your insurance carrier when designing and installing XPO™ burners. Installation should only be undertaken by qualified gas contractors licensed for any regional or local requirements.

Piping weight should be independently supported. Do not use the burner as a piping support or hang weight from the burner's flange connections.

FUELS
XPO™ burners are designed for firing of clean fuel gases such as natural gas or LPG.

EXPECTED EMISSIONS
The XPO™ burner will achieve ultra low NOx emissions while operating at 30% excess air level. The burner provides higher combustion efficiency and lower emissions without the use of expensive FGR or exotic/fragile materials.

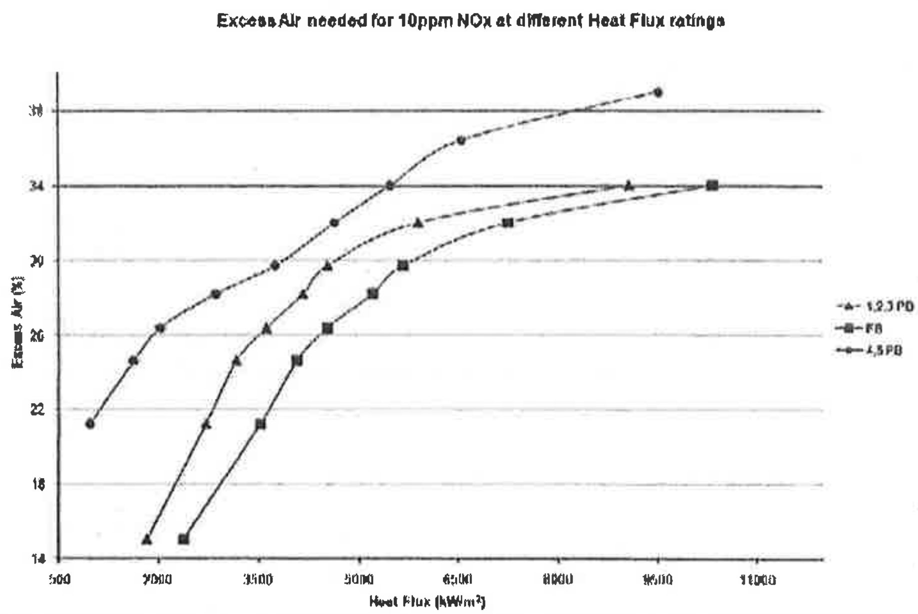
Exact emissions performance may vary in your application. Contact MAXON for information on installation-specific estimates and guaranteed values. No guarantee of emissions is intended or implied without specific, written guarantee from MAXON.

Fire tube sizing

See the table below for ideal fire tube size. The burner should be sized within the range of the suggested heat flux. For best emission performance, the burner should be fired into a fire tube with the lowest suggested heat flux.

HEAT FLUX = BURNER INPUT / FIRE TUBE AREA

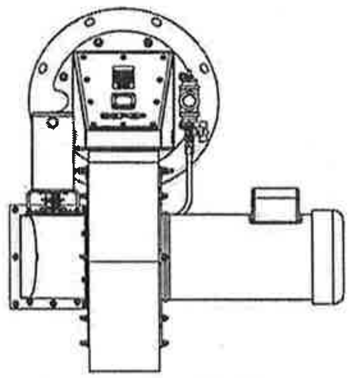
Burner input kW	Burner size	Heat flux	Fire tube size (ID)											
			14 inch	16 inch	18 inch	20 inch	22 inch	24 inch	26 inch	28 inch	30 inch	32 inch	34 inch	36 inch
293	XPO 1 PB	kW/m²	2950	2270	1770									
586	XPO 2 PB			4500	3590	2900	2400							
878	XPO 3 PB				5360	4300	3590	2990						
1244	XPO 3 EB			9580	7580	6130	5080	4270	3630	3130				
1318	XPO 4 PB						5360	4500	3860	3300	2900	2540		
1757	XPO 5 PB						7170	6040	5130	4400	3860	3400	2990	
2342	XPO 5 EB						9530	8040	6860	5900	5130	4490	4000	3590



Below 3631 kW/m² burner turndown will be limited to <3 to 1.

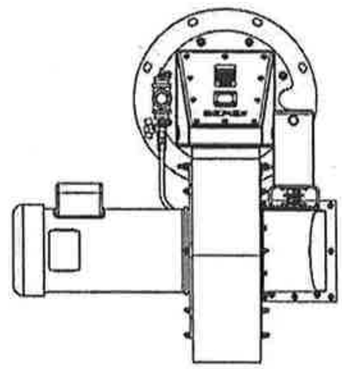
Air valve and air actuator positions

XPO™ burners may be ordered with your choice of air valve position and air actuator position as shown in the drawings below. These drawings below depict XPO™ burners with MAXON SMARTLINK® actuators.



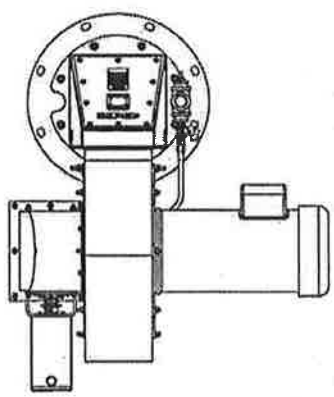
Air valve position: (L) left hand
Actuator position: (T) top of air valve

Actuator rotation for configuration shown above	
SMARTLINK® actuator	Counter-clockwise
General purpose actuator	Clockwise



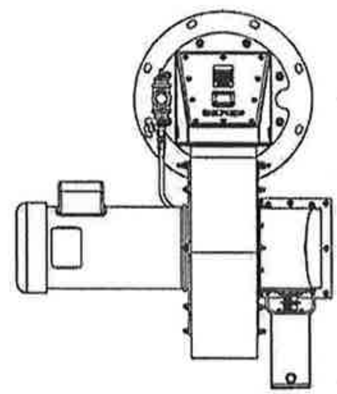
Air valve position: (R) right hand
Actuator position: (T) top of air valve

Actuator rotation for configuration shown above	
SMARTLINK® actuator	Clockwise
General purpose actuator	Counter-clockwise



Air valve position: (L) left hand
Actuator position: (B) bottom of air valve

Actuator rotation for configuration shown above	
SMARTLINK® actuator	Clockwise
General purpose actuator	Counter-clockwise



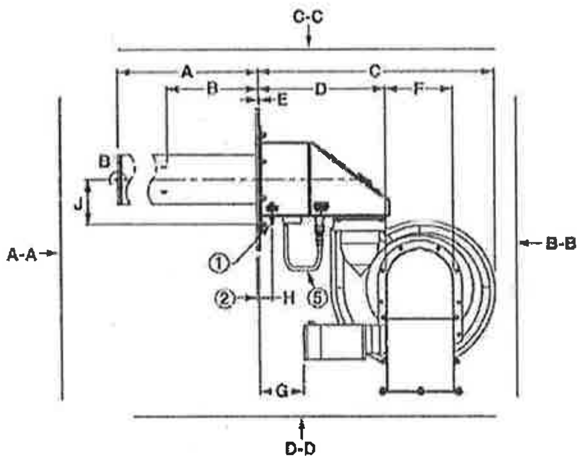
Air valve position: (R) right hand
Actuator position: (B) bottom of air valve

Actuator rotation for configuration shown above	
SMARTLINK® actuator	Counter-clockwise
General purpose actuator	Clockwise

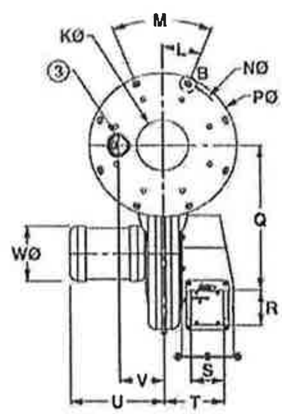
DIMENSIONS

XPO™ 1 PB (packaged) burner

1) Gas pressure test port
2) 6 mm optional oven wall gasket
3) 2" NPT scanner port coupling
4) .15" ± .050" ceramic
5) Scanner cooling air flex line

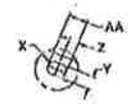


View A-A



Detail A

Detail B



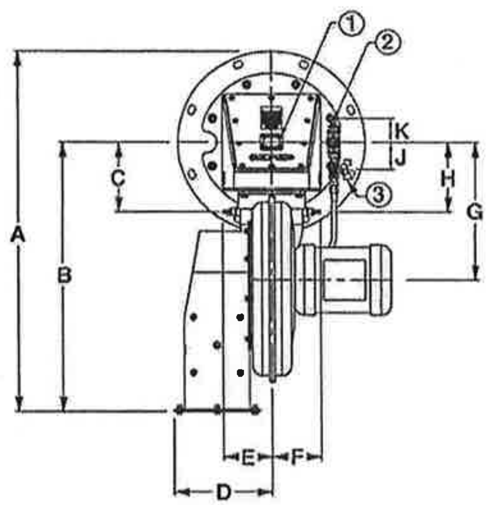
Dimensions in mm unless stated otherwise												
Burner size	A	B	C	D	E	F	G	H	J	K Ø	L	M
XPO 1 PB 2	592	282	734	398	5	208	138	42	146	160	22.5°	45°
XPO 1 PB 4	1145	848										

Burner size	N Ø	P Ø	Q	R	S	T	U	V	W Ø	X	Y	Z	AA
XPO 1 PB 2 XPO 1 PB 4	420	457	465	111	102	185	292	138	178	8	16	11	23

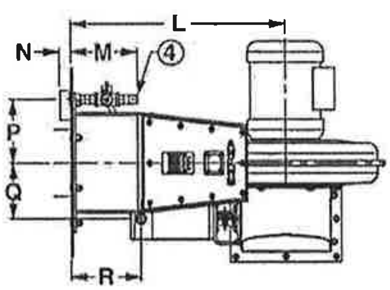
XPO™ 1 PB (packaged) burner

1) Observation window
2) Chamber pressure test port
3) Scanner cooling air valve
4) 1" NPT scanner port
5) Combustion air pressure test port
6) 1/2" NPT S-O ignition wire connection
7) Main gas inlet 1-1/2" NPT
8) 3/8" NPT pilot gas connection
9) Pilot gas pressure test port

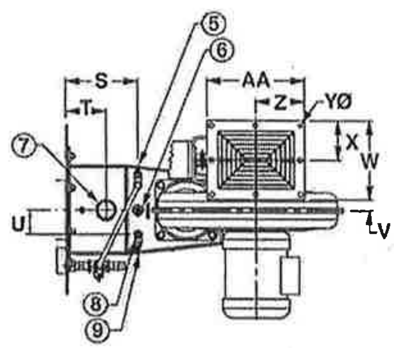
View B-B



View C-C



View D-D

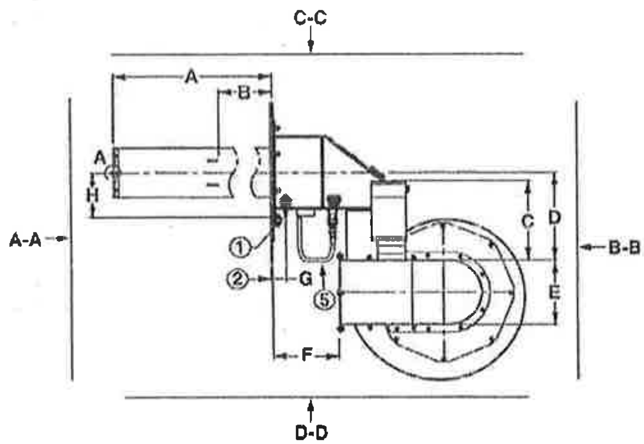


Dimensions in mm unless stated otherwise													
Burner size	A	B	C	D	E	F	G	H	J	K	L	M	N
XPO 1 PB	909	680	175	240	120	120	348	175	68	60	502	156	25

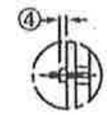
Burner size	P	Q	R	S	T	U	V	W	X	Y Ø	Z	AA
XPO 1 PB	152	135	164	190	105	66	30	210	105	10	130	260

XPO™ 2 & 3 PB (packaged) burner

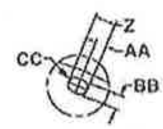
1) Gas pressure test port
2) 6 mm optional oven wall gasket
3) 2" NPT scanner port coupling
4) .15" ± .050 ceramic
5) Scanner cooling air flex line



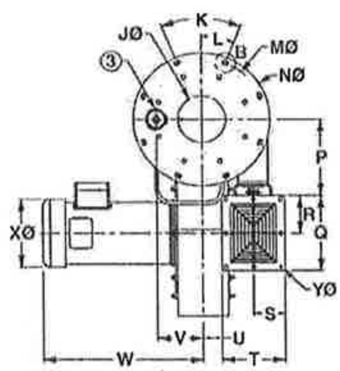
Detail A



Detail B



View A-A



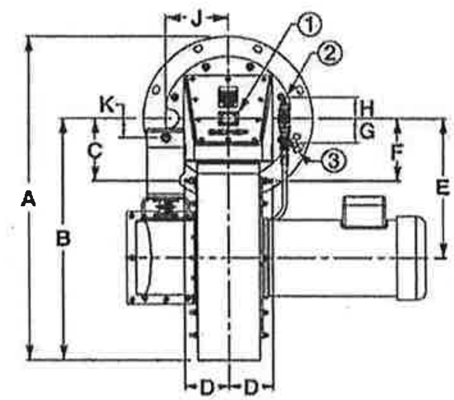
Dimensions in mm unless stated otherwise														
Burner size	A	B	C	D	E	F	G	H	J Ø	K	L	M Ø	N Ø	P
XPO 2 PB 2	592	269	262	288	208	210	42	146	160	45°	22.5°	420	457	262
XPO 2 PB 4	1146	838												
XPO 3 PB 2	592	259												
XPO 3 PB 4	1146	810												

Burner size	Q	R	S	T	U	V	W	X Ø	Y	Z	AA	BB	CC
XPO 2 PB	259	130	105	210	64	152	444	218	10	23	11	16	8
XPO 3 PB							530	234					

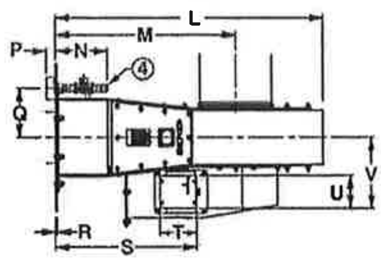
XPO™ 2 & 3 PB (packaged) burner

1) Observation window
2) Chamber pressure test port
3) Scanner cooling air valve
4) 1" NPT scanner port
5) Combustion air pressure test port
6) 1/2" NPT S-O ignition wire connection
7) Main gas inlet 1-1/2" NPT
8) 3/8" NPT pilot gas connection
9) Pilot gas pressure test port

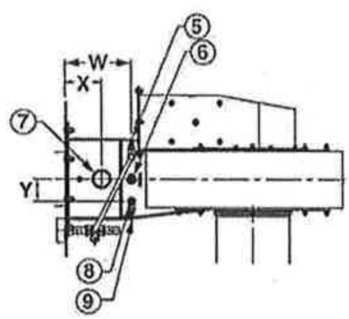
View B-B



View C-C



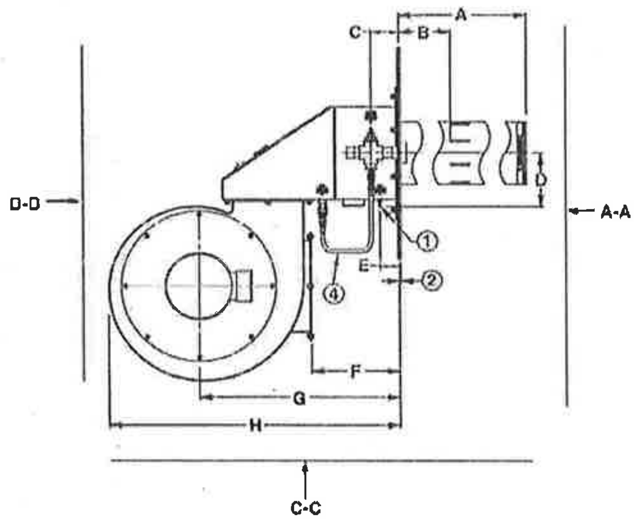
View D-D



Dimensions in mm unless stated otherwise												
Burner size	A	B	C	D	E	F	G	H	J	K	L	M
XPO 2 PB XPO 3 PB	906	678	175	120	392	175	68	60	170	54	805	542

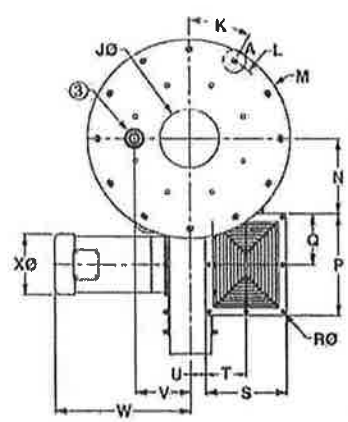
Burner size	N	P	Q	R	S	T	U	V	W	X	Y
XPO 2 PB XPO 3 PB	156	25	152	5	424	111	102	220	190	105	66

XPO™ 4 & 5 PB (packaged) burner



1) Gas pressure test port
2) 6 mm optional oven wall gasket
3) 2-1/2" NPT scanner port coupling
4) Scanner cooling air flex line

View A-A



Detail A

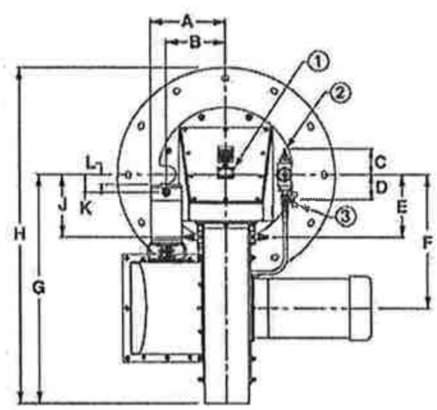
Dimensions in mm unless stated otherwise													
Burner size	A	B	C	D	E	F	G	H	J Ø	K	L Ø	M	N
XPO 4 PB	1096	756	214	180	62	288	657	952	209	30°	641	711	267
XPO 5 PB		736											

Burner size	P	Q	R Ø	S	T	U	V	W	X Ø	Y	Z	AA	BB
XPO 4 PB	363	181	10	286	144	53	216	471	216	8	23	11	16
XPO 5 PB													

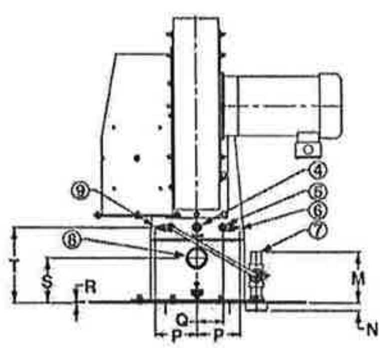
XPO™ 4 & 5 PB (packaged) burner

1) Observation window
2) Chamber pressure test port
3) Scanner cooling air valve
4) 1/2" NPT S-O ignition wire connection
5) 3/8" NPT pilot gas connection
6) Pilot gas pressure test port
7) 1" NPT scanner port
8) 2" NPT main gas inlet
9) Combustion air pressure test port

View B-B



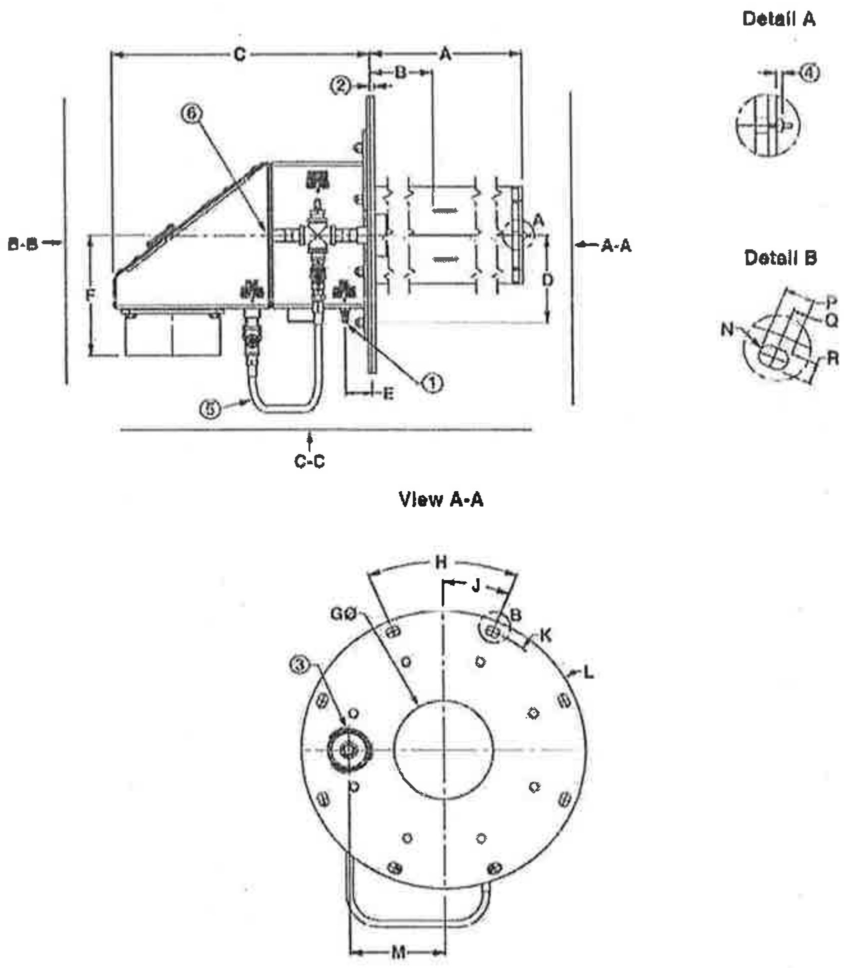
View C-C



Dimensions in mm unless stated otherwise									
Burner size	A	B	C	D	E	F	G	H	J
XPO 4 PB XPO 5 PB	247	196	85	82	209	448	769	1125	209

Burner size	K	L	M	N	P	Q	R	S	T
XPO 4 PB XPO 5 PB	59	33	286	44	139	85	5	149	251

XPO™ 3 EB (external blower) burner



1) Gas pressure test port
2) 6 mm optional oven wall gasket
3) 2" NPT scanner port coupling
4) .15" ± .050 ceramic
5) Scanner cooling air flex line
6) 1" NPT scanner port

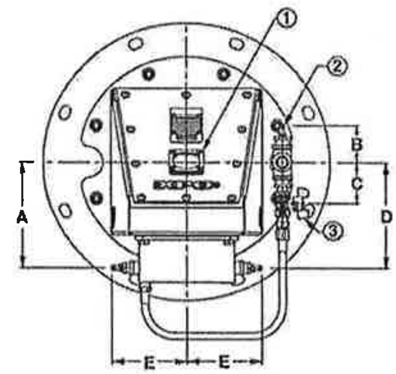
Dimensions in mm unless stated otherwise								
Burner size	A	B	C	D	E	F	G Ø	H
XPO 3 EB 2	591	259	412	145	42	200	160	45°
XPO 3 EB 4	1146	810						

Burner size	J	K	L	M	N	P	Q	R
XPO 3 EB 2	22.5°	420	457	152	8	23	11	16
XPO 3 EB 4								

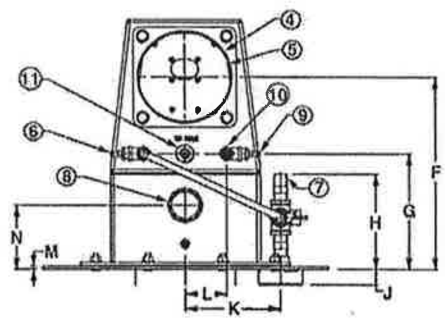
XPO™ 3 EB (external blower) burner

1) Observation window
2) Chamber pressure test port
3) Scanner cooling air valve
4) Ø 152 mm outside combustion air inlet
5) Ø 147 mm inside combustion air inlet
6) Combustion air pressure test port
7) 1" NPT scanner port
8) Main gas inlet 1-1/2" NPT
9) Pilot gas pressure test port
10) 3/8" NPT pilot gas connection
11) 1/2" NPT S-O ignition wire connector

View B-B



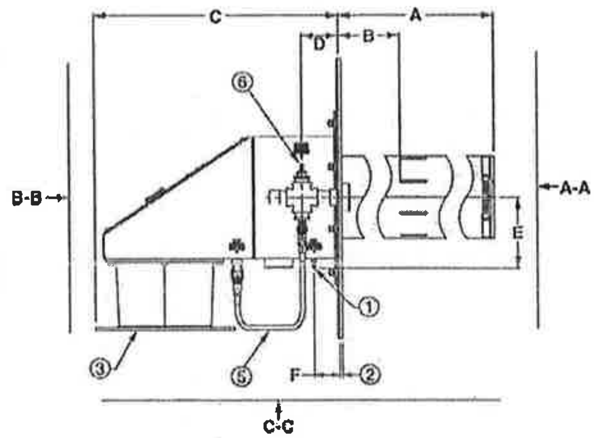
View C-C



Dimensions in mm unless stated otherwise							
Burner size	A	B	C	D	E	F	G
XPO 3 EB 2	175	60	68	175	120	318	190
XPO 3 EB 4							

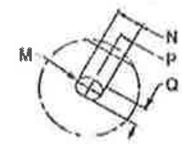
Burner size	H	J	K	L	M	N
XPO 3 EB 2	156	25	152	66	5	105
XPO 3 EB 4						

XPO™ 5 EB (external blower) burner

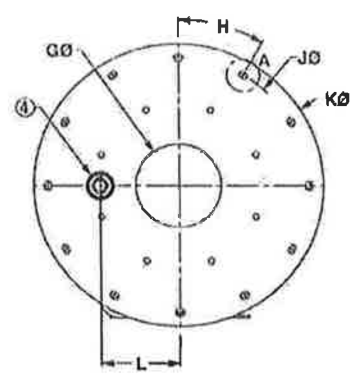


1) Gas pressure test port
2) 6 mm optional oven wall gasket
3) Combustion air inlet
4) 2-1/2" NPT scanner port coupling
5) Scanner cooling air flox line
6) Chamber pressure test port

Detail A



View A-A



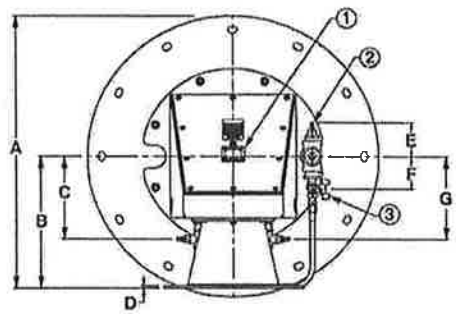
Dimensions in mm unless stated otherwise								
Burner size	A	B	C	D	E	F	G Ø	H
XPO 5 EB	1096	737	600	214	180	62	209	30°

Burner size	J Ø	K Ø	L	M	N	P	Q
XPO 5 EB	641	711	216	8	23	11	16

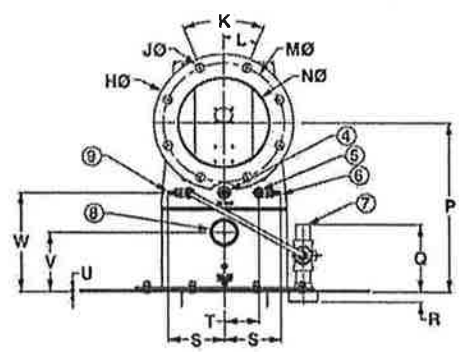
XPO™ 5 EB (external blower) burner

1) Observation window
2) Chamber pressure test port
3) Scanner cooling air valve
4) 1/2" NPT S-O ignition wire connector
5) 3/8" NPT pilot gas connection
6) Pilot gas pressure test port
7) 1" NPT scanner port
8) Main gas inlet 2" NPT
9) Combustion air pressure test port

View B-B



View C-C

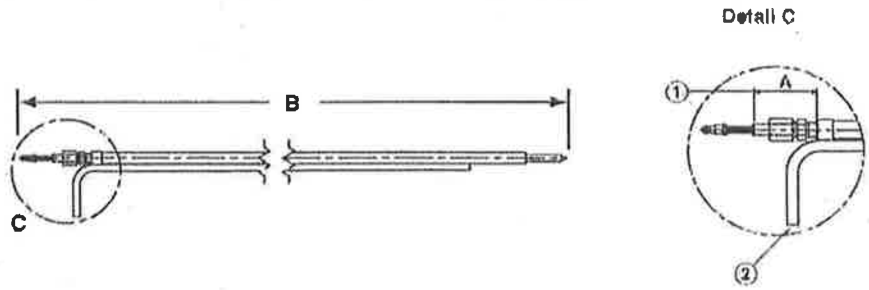


Dimensions in mm unless stated otherwise											
Burner size	A	B	C	D	E	F	G	H Ø	J Ø	K	L
XPO 5 EB	690	334	209	6	85	82	209	343	22	45°	22.5°

Burner size	M Ø	N Ø	P	Q	R	S	T	U	V	W
XPO 5 EB	298	221	429	286	43	139	85	5	149	251

Spark ignitor pilot tube assembly for sizes XPO 1, 2 and 3

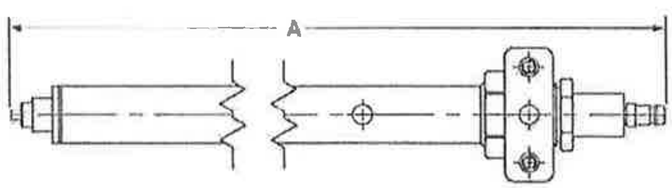
1) Spark ignitor set-up dimension
2) 3/8" pilot gas tubing



Dimensions in mm unless stated otherwise		
Burner size	A	B
XPO 1 PB 2 XPO 2 PB 2 XPO 3 PB 2 XPO 3 EB 2	52	866
XPO 1 PB 4 XPO 2 PB 4 XPO 3 PB 4 XPO 3 EB 4	52	1422

Note: Valid for burners shipped prior to 8/12/2012.

Spark ignitor for sizes XPO 1, 2, 3, 4 & 5



Dimensions in mm unless stated otherwise	
Burner size	A
XPO 1 PB 2	818
XPO 2 PB 2	
XPO 3 PB 2	
XPO 3 EB 2	
XPO 1 PB 4	1375
XPO 2 PB 4	
XPO 3 PB 4	
XPO 3 EB 4	
XPO 4 PB 4	
XPO 5 PB 4	
XPO 5 EB 4	

INSTALLATION AND OPERATING INSTRUCTIONS FOR XPO™ BURNERS

Please read the operating and mounting instructions before using the equipment. Install the equipment in compliance with the prevailing regulations.

Bedrijfs- en montagehandleiding voor gebruik goed lezen! Apparaat moet volgens de geldende voorschriften worden geïnstalleerd.

Lire les instructions de montage et de service avant utilisation! L'appareil doit imperativement être installé selon les règlementations en vigueur.

Betriebs- und Montageanleitung vor Gebrauch lesen! Gerät muß nach den geltenden Vorschriften installiert werden.

Application requirements

VIEW PORT
A view port to observe burner flame is helpful to inspect flame aspect. Locate the view port downstream of the flame, looking back to the burner. Make sure the complete flame can be evaluated.

SUPPORT BURNER AIR AND GAS PIPING
The XPO™ burner shall not be used as support for the piping to the burner. Gas and air piping shall be supported in such a way that no additional loads will be created on the burner.

BURNER MOUNTING FLANGE LOADS
Check burner weight and reinforce burner mounting flange or combustion chamber/furnace back wall if necessary to take complete burner weight.

INSTALLATION INSTRUCTIONS

STORAGE OF XPO™ BURNERS
XPO™ burners shall be stored dry (inside).

HANDLING OF XPO™ BURNERS
Handle burners with care during unpacking, transport, lifting and installation. Use proper equipment. Any impact on the burner could result in damage.

Burner assembly instructions

Packaged burners will be shipped with blowers, blast tubes and fuel valves removed. Burner requires assembly prior to installation.

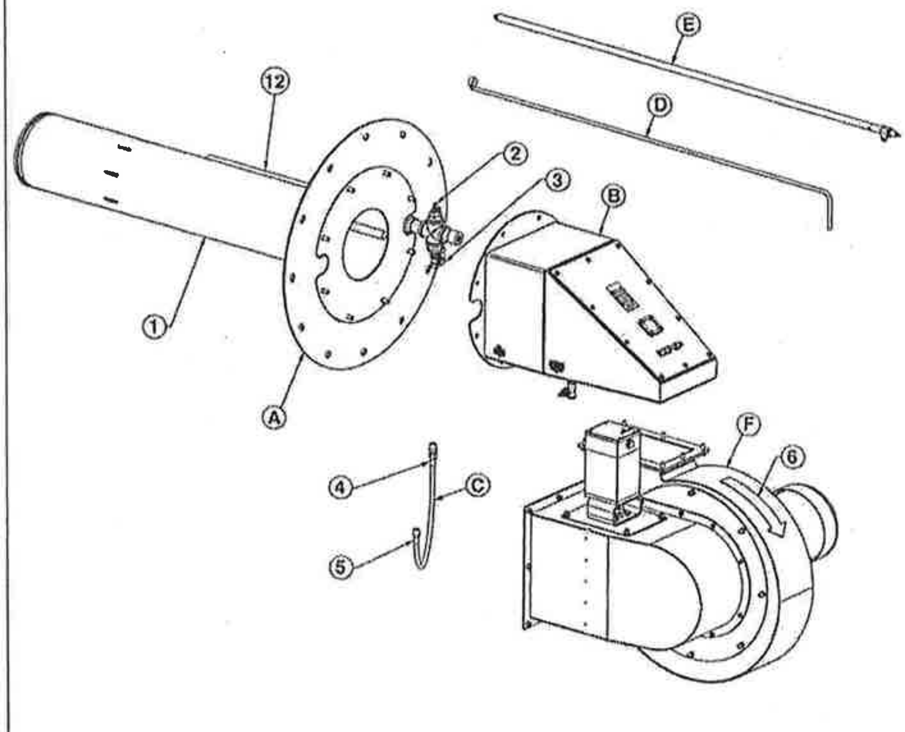
The following components will be included in the shipping carton:

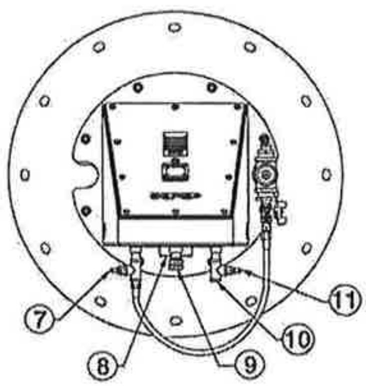
- Housing and manifold assembly (B)
- Blower and air valve assembly (packaged versions only) (F)
- Fuel valve assembly
- Blast tube assembly (A)
- Scanner cooling air flex hose (C)

Assemble burner components using the instructions and diagrams below and on the following pages as a guide.

- Insulate and install blast tube assembly (A) according to catalog instructions.
- Pipe fuel line and control valve to burner assembly.
- Pipe pilot gas line and connect ignition wire to manifold assembly (B).
- Attach blower and air valve assembly (F) for packaged burners or EB adapter for external blower.

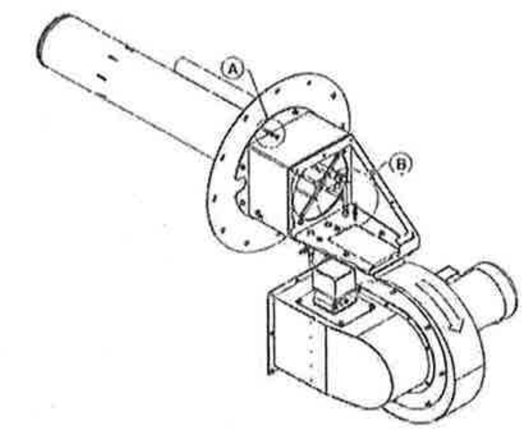
1) Blast tube (insulation not shown)
2) Chamber pressure test connection
3) Scanner cooling air valve
4) Attach swivel end of flex hose to scanner cooling air valve
5) Attach fixed end of flex hose to combustion air pressure connection
6) Impeller rotation
7) Combustion air test connection
8) Main fuel inlet
9) Ignition wire S-O cord connector
10) Pilot gas inlet
11) Pilot gas test connection
12) Customer-supplied scanner tube



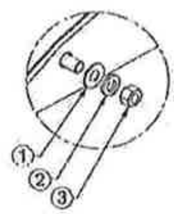


INSTALLATION OF IGNITOR AND PILOT GAS LINE

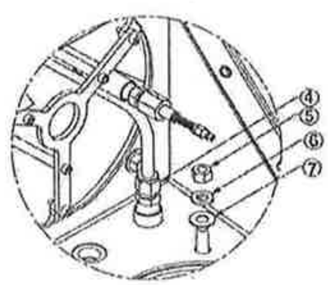
1) 3/8" flat washer
2) 3/8" split lock washer
3) 3/8" -16 nut
4) Pilot gas tube nut
5) 3/8" -16 nut
6) 3/8" split lock washer
7) 3/8' flat washer
8) Pilot gas tubing
9) Ignitor
10) Two 10-24 ignitor screws
11) Spark ignitor bracket
12) 10-24 socket head cap screw



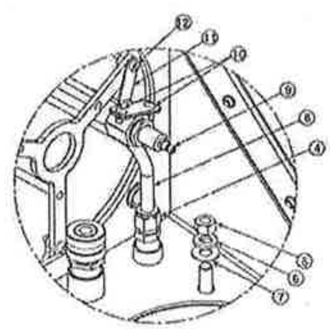
Detail A



Detail B1



Detail B2



DETAIL B1 - FOR SIZES XPO 1-3 (SHIPPED PRIOR TO 8/12/2012):

- Insert spark ignitor into blast tube's ignitor tube. (Mixing disc and tripod assembly inside manifold may need to be rotated for clearance.)
- Connect pilot tube to manifold.
- Confirm spark ignitor set-up dimension as shown in catalog literature.
- Tighten all hardware, noting that O-ring must be present between nut and ceramic and the spark ignitor nut needs only be hand tight plus 1/4 turn to prevent cracking ceramic.
- Connect ignition wire to spark ignitor.

DETAIL B2 - FOR SIZES XPO 1-3 (SHIPPED AFTER 8/12/2012) AND XPO 4 & 5:

- Remove acorn nut from mixing disc portion of manifold assembly.
- Slide pilot gas tube ring over blast tube's ignitor tube.
- Connect pilot tubing to manifold.
- Insert spark ignitor into blast tube ignitor tube and shoulder spark ignitor into blast tube disc.
- Attach spark ignitor bracket using acorn nut previously removed.
- Tighten the two ignitor bracket screws.
- Tighten all hardware.
- Connect ignition wire to spark ignitor.

Burner mounting instructions

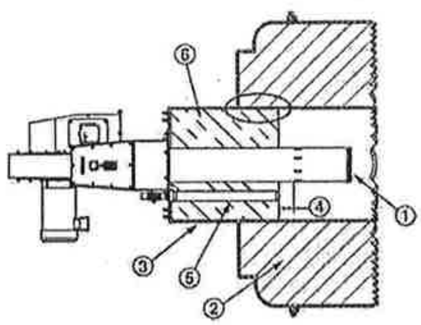
FLANGE THE BURNER TO THE INSTALLATION
Bolt the burner to the installation's burner mounting flange. Use proper gasketing. Tighten the flange bolting with correct torque. Retighten all bolts after first firing and regularly after commissioning.

All non-liquid cooled surfaces must be insulated as shown in burner mounting diagram. **Area(s) between fire tube wall and outside of burner blast tube must be completely filled with insulation as shown below.** Customer-supplied scanner tube must not extend beyond the blast tube insulation.

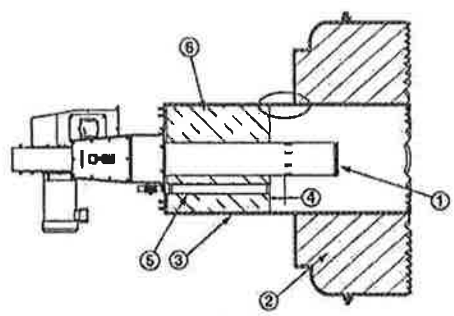
BURNER MOUNTING

1) Blast tube
2) Liquid solution
3) Fire tube
4) 152 mm gap required from insulation to slots
5) Customer-supplied scanner tube
6) Customer-supplied insulation (minimum 152 mm depth from blast tube flange)*

Correct Installation
Blast tube is completely insulated beyond point where fire tube is solution backed. Minimum of 3" insulation into liquid.



Incorrect application/installation
Blast tube cannot be completely insulated due to protrusion length of fire tube out of solution.



*Recommended insulation properties: minimum density of 16 kg/m³ or greater with minimum thermal conductivity of 12 W/m.K at 980°C.

Follow all applicable codes including regional codes, local directives, standards and recommendations of your insurance carrier when designing and installing XPO™ burners. Installation should only be undertaken by qualified gas contractors licensed for any regional or local requirements.

Piping weight should be independently supported. Do not use the burner as a piping support or hang weight from the burner's flange connections.

XPO™ burners should be used in liquid backed applications. All non-liquid cooled surfaces must be insulated as shown above.

Both packaged (PB) and external blower (EB) versions include two different choices for blast tube length. A 610 mm or 1220 mm long blast tube is available. Blast tube length should be selected based on the wall penetration depth or non-liquid cooled portion of fire tube.

START-UP INSTRUCTIONS FOR XPO™ BURNERS

Instructions provided by the company or individual responsible for the manufacture and/or overall installation of a complete system incorporating MAXON burners take precedence over the installation and operating instructions provided by MAXON. If any of the instructions provided by MAXON are in conflict with local codes or regulations, please contact MAXON before initial start-up of equipment.

Read the combustion system manual carefully before initiating the start-up and adjustment procedure. Verify that all of the equipment associated with and necessary to the safe operation of the burner system has been installed correctly, that all pre-commissioning checks have been carried out successfully and that all safety-related aspects of the installation are properly addressed.

Initial adjustment and light-off should be undertaken only by a trained commissioning engineer.

Do not operate the burner without the burner cover and observation window securely attached and sealed to the burner air housing.

CHECKS DURING AND AFTER START-UP

During and after start-up, check the integrity of the system. Check all bolted connections after first firing (first time on temperature) and retighten if necessary.

PILOT IGNITION

Before ignition of the pilot, adjust the combustion air to the minimum burner air flow. Pilot will not ignite if too high an air flow exists. Set pilot gas flow to the correct value before pilot ignition attempt.

MAIN BURNER IGNITION

Set correct gas flow for burner minimum capacity before attempt of main burner ignition. After ignition of main burner, allow some time on minimum capacity to allow the burner parts to heat up slowly.

ADJUST AIR/GAS RATIO, SET MAXIMUM CAPACITY

Once the main flame is ignited, adjust air/gas ratio of the burner to have the required combustion quality and slowly increase capacity. Do not increase capacity too fast to avoid damage to burner parts or furnace due to excessive temperature gradient. Stack O_2 should be used to do final set-up of air/fuel ratio.

MAINTENANCE AND INSPECTION INSTRUCTIONS

SAFETY REQUIREMENTS

Regular inspection, testing and recalibration of combustion equipment according to the installation manual is an integral part of its safety. Inspection activities and frequencies shall be carried out as specified in the installation manual.

VISUAL INSPECTIONS

Regular visual inspection of all connections (air and gas piping to the burner, bolting of the burner to the furnace) and burner flame size and aspect are essential.

SPARE PARTS

Keep local stock of spark ignitor. It is not recommended to keep local stock of other burner parts. Consult installation manual for burner spare parts and system accessories.

ATTACHMENT II
Emission Profiles

Permit #: S-4159-7-3	**Last Updated**
Facility: SENECA RESOURCES CORP	07/26/2017 EDGEHILR

Equipment Pre-Baselined: NO

	NOX	SOX	PM10	CO	VOC
Potential to Emit (lb/Yr):	6205.0	694.0	730.0	33763.0	6443.0
Daily Emis. Limit (lb/Day)	16.3	1.8	1.9	88.8	17.0
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	0.0	0.0	0.0	0.0	0.0
Q2:	0.0	0.0	0.0	0.0	0.0
Q3:	0.0	0.0	0.0	0.0	0.0
Q4:	0.0	0.0	0.0	0.0	0.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio					
Quarterly Offset Amounts (lb/Qtr)					
Q1:					
Q2:					
Q3:					
Q4:					

Application Emissions

Permit #: S-4159-10-0	**Last Updated**
Facility: SENECA RESOURCES CORP	06/12/2017 EDGEHILR

Equipment Pre-Baselined: NO

	NOX	SOX	PM10	CO	VOC
Potential to Emit (lb/Yr):	964.0	250.0	613.0	3241.0	175.0
Daily Emis. Limit (lb/Day)	2.6	0.7	1.7	8.9	0.5
Quarterly Net Emissions Change (lb/Qtr)					
Q1:	241.0	62.0	153.0	810.0	43.0
Q2:	241.0	62.0	153.0	810.0	44.0
Q3:	241.0	63.0	153.0	811.0	44.0
Q4:	241.0	63.0	154.0	811.0	44.0
Check if offsets are triggered but exemption applies	N	N	N	N	N
Offset Ratio	1.5	1.5	1.5		
Quarterly Offset Amounts (lb/Qtr)					
Q1:	361.0	93.0	230.0		
Q2:	362.0	94.0	230.0		
Q3:	362.0	94.0	230.0		
Q4:	362.0	94.0	230.0		

ATTACHMENT III
BACT Analysis

Top Down BACT Analysis for NOx Emissions:

District Rule 4320 includes a compliance option that limits units greater than 5 MMBtu/hr and less than 20 MMBtu/hr to 9 ppm @ 3% O_2. This emission limit is achieved in Practice control technology for the BACT analysis. District Rule 4320 also contains an enhanced schedule option that allows applicants additional time to meet the requirements of the rule. The enhanced schedule NOx emission limit requirement is 6 ppmv @ 3% O_2. Since this is an enhanced option in the rule, it will be considered the Technologically Feasible control technology for the BACT analysis.

The following are possible control technologies:

1. 9 ppmvd @ 3% O2 - Achieved in Practice.
2. 6 ppmvd @ 3% O2 with SCR – Technologically Feasible

Step 2 - Eliminate Technologically Infeasible Options

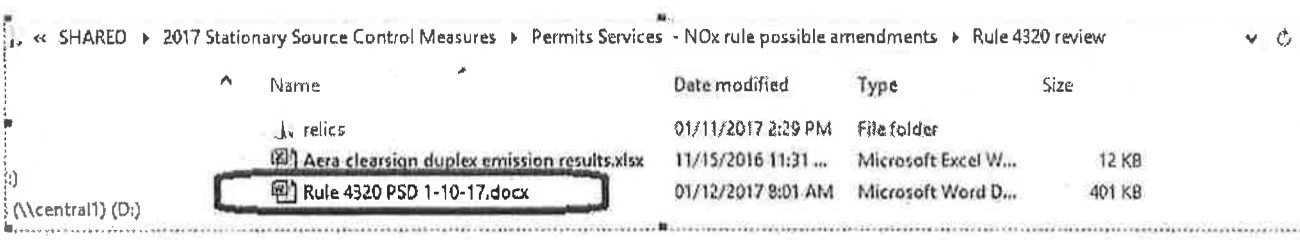
None of the above listed technologies are technologically infeasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 9 ppmvd @ 3% O2 - Achieved in Practice.
2. 6 ppmvd @ 3% O2 with SCR – Technologically Feasible

Step 4 - Cost Effectiveness Analysis

A cost effective analysis is required for Technologically Feasible Control Options that are not proposed. The estimated cost of SCR was obtained from the following:



SCR System Cost

R.F. MacDonald Co (Contact: Rob Schmitz, (209) 595-5523)

Budgetary estimates for an SCR system, which includes ammonia injection grid, air dilution and ammonia flow control skid, reactor housing, transition and catalyst, for various size boilers are summarized in the following table. The estimates **do not** include installation cost, freight expenses and sales tax (no tax on installation labor). The vendor stated that the **installation costs are roughly around 50% of the equipment cost**. The estimates are for anhydrous ammonia bottle skids. The cost would be $100,000 more for installations that needs urea to ammonia conversion system (for example, correctional institutions).

Boiler Size	SCR System Equipment Cost ($)*
≤ 20 MMBtu/hr	$150,000
50 MMBtu/hr – 100 MMBtu/hr	$180,000
>100 MMBtu/hr (Custom)	$200,000-$250,000

*SCR systems using anhydrous ammonia bottle skids

Therefore the estimated SCR installation cost is $225,000. It is assumed that the cost of SCR for a small boiler is comparable to that of a heater treater.

Annualized Capital Cost

Equivalent Annual Capital Cost (Capital Recovery)

$$A = P \frac{i(1+i)^n}{(1+i)^n - 1}$$ where;

A = Equivalent Annual Control Equipment Capital Cost
P = Present value of the control equipment, including installation cost
i = interest rate (use 10%, or demonstrate why alternate is more representative of the specific operation).
n = equipment life (assume 10 years or demonstrate why alternate is more representative of the specific operation)

Where

P = $225,000 (assuming the lower of range values is applicable for a 10 MMBtu/hr unit , conservative)
i = 10%,
n = 10 years

A = 0.1627 x $ 225,000
= $36,616/yr

Industrial Standard NOx Emissions = 10 MMBtu/hr x 0.018 lb/MMBtu x 8760 hrs/year
= 1,577 lb/year

Tech. Feasible NOx Emissions = 10 MMBtu/hr x 0.007 lb/MMBtu x 8760 hrs/year
= 613 lb/year

<u>NOx reduction due to SCR:</u>

Total reduction = Emissions $_{(15\ ppmv)}$ – Emissions $_{(6\ ppmv)}$
Total reduction = (1,577 lb/yr – 613 lb/yr)/2000 lb/ton
Total reduction = 0.5 ton/yr

<u>Cost effectiveness</u>

Cost effectiveness = $ 36,616/yr/ 0.5 ton/yr
Cost effectiveness = $ 73,232/ton NOx

The cost effectiveness is greater than the $24,500/ton NOx cost effectiveness threshold of the District BACT policy. Therefore the use of SCR with ammonia injection is not cost effective and is not required as BACT for NOx.

Step 5 - Select BACT

BACT is satisfied by the applicant's proposal to meet a NOx limit of 9 ppmvd @ 3% O_2 to be achieved with a low NO_x burner.

ATTACHMENT IV
HRA/AAQA

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Richard Edgehill – Permit Services
From:	Jessica Rosas – Technical Services
Date:	July 19, 2017
Facility Name:	Seneca Resources
Location:	T11N, R23W, Section 7
Application #(s):	S-4159-10-0
Project #:	S-1171562

A. RMR SUMMARY

RMR Summary						
Units	**Prioritization Score**	**Acute Hazard Index**	**Chronic Hazard Index**	**Maximum Individual Cancer Risk**	**T-BACT Required?**	**Special Permit Requirements?**
Unit 10-0 (Heater Treater)	0.00	N/A[1]	N/A[1]	N/A[1]	No	Yes
Project Totals	0.00	N/A[1]	N/A[1]	N/A		
Facility Totals	<1	0.00	0.00	0.00		

[1] The project passed on prioritization with a score less than1; therefore, no further analysis was required.

Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 10-0

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.

B. RMR REPORT

I. Project Description

Technical Services received a request on July 3, 2017, to perform a Risk Management Review for a proposed installation of a heater treater connected to a vapor control system.

II. Analysis

Toxic emissions for this proposed unit were derived from data in the 1992 Radian Corporation report to WSPA, and input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed unit was less than 1.0 (see RMR Summary Table). However, further analysis was necessary in order to verify that unit 10-0 pollutant emissions perform below AAQA standards per District Rule 2201.

The following parameters were used for the review:

Analysis Parameters Unit 10-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	7.62	**Closest Receptor (m)**	701
Stack Diameter. (m)	0.76	**Type of Receptor**	Residential
Stack Exit Velocity (m/s)	0.69	**Max Hours per Year**	8760
Stack Exit Temp. (°K)	430	**Fuel Type**	NG
Fuel Usage (mmscf/hr)	0.01	**Fuel Usage (mmscf/yr)**	3.65

Technical Services performed modeling for criteria pollutants CO, NO_x, SO_x, and PM10 with the emission rates below:

Unit #	NO_x (Lbs.)		SO_x (Lbs.)		CO (Lbs.)		PM_{10} (Lbs.)	
	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.
10-0	0.108	964	0.030	250	0.371	3241	0.071	613

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

	Background Site	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Arvin-Di Giorgio (2016)	Pass	X	Pass	X	X
NO_x	Bakersfield-California (2016)	Pass[1]	X	X	X	Pass
SO_x	Fresno – Garland (2015)	Pass	Pass	X	Pass	Pass
PM_{10}	Bakersfield-California (2016)	X	X	X	Pass[2]	Pass[2]
$PM_{2.5}$	Bakersfield-Southeast (2015)	X	X	X	Pass[3]	Pass[3]

*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).
[3]The court has vacated EPA's $PM_{2.5}$ SILs. Until such time as new SIL values are approved, the District will use the corresponding PM_{10} SILs for both PM_{10} and $PM_{2.5}$ analyses.

III. Conclusion

The prioritization score is less than 1.0. **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 requirements 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.

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

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Prioritization score w/ toxic emissions summary
D. Convert
E. Facility Summary
F. AAQA Summary

ATTACHMENT V
Statewide Compliance Statement

San Joaquin Valley
Unified Air Pollution Control District
DETERMINATION OF COMPLIANCE STATEMENT

Company Name: Seneca Resources	Facility ID(s) S-X: 1114; 3007; 3755; 4159

All major Stationary Source(s) owned or operated by Seneca Resources in California that are subject to emission limitations are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

Oct.13.17

Signature of Responsible Official   Date

Timothy R. Alburger

Name of Responsible Official (please print)

Senior Advisor, EHSQ

Title of Responsible Official (please print)

Deliver to:

San Joaquin Valley Unified
Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

ATTACHMENT VI
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-4159-7-3 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: SENECA RESOURCES CORP
MAILING ADDRESS: 4800 CORPORATE CT
BAKERSFIELD, CA 93311

LOCATION: HEAVY OIL WESTERN

SECTION: NW7 **TOWNSHIP:** 11N **RANGE:** 23W

EQUIPMENT DESCRIPTION:
MODIFICATION OF THERMALLY ENHANCED OIL RECOVERY OPERATION SERVING 40 STEAM ENHANCED WELLS WITH OPEN CASING VENTS SERVED BY VAPOR CONTROL SYSTEM INCLUDING COMPRESSOR(S), GAS/LIQUID SEPARATOR, AND 10.4 MMBTU/HR FLARE: CONNECT HEATER TREATER S-4159-10 TO VAPOR CONTROL SYSTEM

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
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 NSR Rule]
3. TEOR wells shall be authorized to operate with open or closed casing vents. [District Rule 2201 and 4401]
4. Production from TEOR wells operated with closed casing vents shall be sent only to tanks equipped with 99% vapor control. [District Rules 2201 and 4401]
5. Vapors from TEOR wells operated with open casing vents shall be sent to only to vapor control system served by 10.4 MMBtu/hr flare. [District Rule 2201]
6. Leaks exceeding an instrument reading of 10,000 ppmv are a violation of this permit. [District Rules 2201 and 4401]
7. Fugitive VOC emissions from TEOR operation shall not exceed 1.9 lb/day. [District Rule 2201]
8. Components shall be inspected quarterly for leaks, using a portable hydrocarbon detection instrument in accordance with EPA Method 21. [District Rules 1070 and 4401]

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

DRAFT

Arnaud Marjollet, Director of Permit Services

S-4159-7-3 : Jul 26 2017 9:27AM – EDGEHILR : Joint Inspection NOT Required

9. Permittee shall maintain records of the date and well identification where steam injection or well stimulation occurs, current list of all thermally enhanced production wells associated with this operation with identification of wells operated with closed and open casing vents, leak inspection results, and accurate fugitive component counts of components in gas service and resulting emissions calculated using the emission factors in the CAPCOA California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, Table IV-2c, Oil and Gas Production Screening Value Ranges Emission Factors (Feb 1999) . [District Rule 4401]

10. This permit shall not authorize the utilization of any IC engine, or other combustion device requiring a separate permit, for powering the air assist to the flare. [District Rule 2201]

11. The flare shall be operated according to the manufacturer's specifications, a copy of which shall be maintained on site. [District Rule 2201]

12. Flare shall be equipped with air assist which shall be utilized when needed to maintain visible emissions below Ringlemann 1/4 and 5% opacity. [District Rule 2201]

13. A flame shall be present at all times when combustible gases are vented through this flare. [District Rule 2201]

14. Sulfur concentration of gas combusted in flare shall not exceed 2.66 gr S/100 scf (45 ppmv H2S). [District Rule 2201]

15. Flare shall be equipped with total gas volume flow meter. [District Rule 2201]

16. Maximum amount of gas combusted shall not exceed 250 MMBtu/day. [District Rule 2201]

17. Maximum amount of gas combusted shall not exceed 91,250 MMBtu/yr. [District Rule 2201]

18. Emissions from the flare shall not exceed any of the following limits (based on total gas combusted): NOx (as NO2): 0.068lb/MMBtu; PM10: 0.008 lb/MMBtu; CO: 0.37 lb/MMBtu; or VOC: 0.063 lb/MMBtu. [District Rule 2201]

19. Permittee shall measure the sulfur content of the gas combusted by District witnessed, or authorized, sample collection by ARB certified testing laboratory at startup and annually thereafter or upon change of source of flared gas. Such data shall be submitted to the District within 60 days of sample collection. [District Rules 1081, 7.2 and 2201]

20. The sulfur content of the combusted gas shall be determined using ASTM test methods D-1072, D-3246, D-6228, or double GC for H2S and Mercaptans. H2S concentration (ppmv) of the gas shall be determined using ASTM test methods D-1072 or D-4084, using Draeger tube, or by gas supplier test data consistent with the natural gas fuel sulfur content test method listed in this permit. [District Rule 1081]

21. The higher heating value of the flared gas shall be monitored at least quarterly or upon change of source of flared gas. [District Rules 1070 and 2201]

22. Measured heating value and quantity of gas flared shall be used to determine compliance with heat input limits. [District Rule 2201]

23. Permittee shall keep accurate records of daily and annual heat input to the flare in MMBtu/day and MMBtu/yr. [District Rule 2201]

24. All records required by this permit shall be maintained and retained on-site for a minimum of five (5) years and made available for District, ARB, and EPA inspection upon request. [District Rule 1070]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-4159-10-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: SENECA RESOURCES CORP
MAILING ADDRESS: 4800 CORPORATE CT
BAKERSFIELD, CA 93311

LOCATION: HEAVY OIL WESTERN

EQUIPMENT DESCRIPTION:
10 MMBTU/HR NATURAL GAS-FIRED HEATER TREATER WITH TWO SEPARATE 5.0 MMBTU/HR LOW NOX BURNERS

CONDITIONS

1. Prior to operating equipment under this Authority to Construct, permittee shall surrender NOX emission reduction credits for the following quantity of emissions: 1st quarter - 361 lb, 2nd quarter - 361 lb, 3rd quarter - 362 lb, and fourth quarter - 362 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]
2. ERC Certificate Number S-4821-2 (or a certificate split from this certificate) 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]
3. Prior to operating equipment under this Authority to Construct, permittee shall surrender SOX emission reduction credits for the following quantity of emissions: 1st quarter - 93 lb, 2nd quarter - 94 lb, 3rd quarter - 94 lb, and fourth quarter - 94 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]
4. ERC Certificate Number S-4824-5 (or a certificate split from this certificate) 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]

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

DRAFT

Arnaud Marjollet, Director of Permit Services

S-4159-10-0 : Aug 7 2017 11:51AM -- EDGEHILR , Joint Inspection NOT Required

5. Prior to operating equipment under this Authority to Construct, permittee shall surrender PM10 emission reduction credits for the following quantity of emissions: 1st quarter - 230 lb, 2nd quarter - 230 lb, 3rd quarter - 230 lb, and fourth quarter - 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]

6. ERC Certificate Number S-1409-4 (or a certificate split from this certificate) 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]

7. The exhaust stacks 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]

8. Particulate matter emissions shall not exceed 0.1 grain/dscf at operating conditions, nor 0.1 grain/dscf calculated to 12% CO_2, nor 10 lb/hr. [District Rules 4201, 4301, 5.1 and 5.2.3]

9. Heater treater shall only be fired on PUC-regulated natural gas with a sulfur content not exceeding 1.0 gr S/100 scf. [District Rule 2201]

10. Emission rates shall not exceed: NOx (as NOx): 9 ppmvd @ 3% O_2 or 0.011 lb-NOx/MMBtu PM10: 0.007 lb/MMBtu; CO: 50 ppmvd @ 3% O_2 or 0.037 lb-CO/MMBtu; or VOC: 0.002 lb/MMBtu. [District Rule 2201, 4305, 4306, and 4320]

11. The VOC content of the gas shall not exceed 10% by weight. [District Rule 2201]

12. Operator shall conduct quarterly gas sampling for gas exiting the separator pressure vessel to qualify for exemption from fugitive component counts for components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

13. Source testing to measure natural gas-combustion NOx and CO emissions from this unit shall be conducted at least once every twelve (12) months (no more than 30 days before or after the required annual source test date). After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months (no more than 30 days before or after the required 36-month source test date). 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 2201, 4305, 4306 and 4320]

14. 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]

15. 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 2201, 4305, 4306 and 4320]

16. The following test methods shall be used: NOX (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19; CO (ppmv) - EPA Method 10 or ARB Method 100; Stack gas oxygen (O_2) - EPA Method 3 or 3A or ARB Method 100; stack gas velocities - EPA Method 2; Stack gas moisture content - EPA Method 4; SOx - EPA Method 6C or 8 or ARB Method 100; fuel gas sulfur as H_2S content - EPA Method 11 or 15; and fuel hhv (MMBtu) - ASTM D 1826 or D 1945 in conjunction with ASTM D 3588. [District Rule 2201, 4305, 4306, 4320]

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

18. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

19. The permittee shall monitor and record the stack concentration of NOx, CO, and O_2 at least once every month (in which a source test is not performed) using a portable analyzer 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, 4306, and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

20. If the NOx or CO concentrations corrected to 3%, as measured by the portable analyzer, exceed the applicable emission limit, 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 4102, 4305, 4306 and 4320]

21. All NOx, CO, and O2 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 NOx, CO, and O2 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 sample 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 4102, 4305, 4306 and 4320]

22. 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, 4306, and 4320]

23. The permittee shall maintain records of: (1) the date and time of NOx, CO and O2 measurements, (2) the O2 concentration in percent by volume 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, 4306 and 4320]

24. 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 PTO, 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. For the purposes of permittee-performed alternate monitoring, emissions measurements may be performed at any time after the unit reaches conditions representative of normal operation. [District Rules 4305, 4306 and 4320]

25. 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]

26. Fuel sulfur content shall be determined using EPA Method 11 or Method 15. [District Rule 4320]

27. Permittee shall maintain accurate records of valid purchase contracts, supplier certifications, tariff sheets, or transportation contracts used to satisfy the fuel sulfur content analysis of fuel combusted in process heater, provided they establish the fuel sulfur concentration and higher heating value. [District Rule 2201 and 4320]

28. The permittee shall keep accurate records of the date VOC sampling occurred, who performed the sampling and testing, and the results. [District Rule 2520]

29. Permittee shall comply with all applicable testing, recordkeeping, and reporting requirements specified in Rule 4001 - New Source Performance Standards, including but not limited to Subparts A and Ja. [District Rule 4001]

30. All monitoring data, support information and records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rules 1070, 4305, 4306, and 4320]

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