



April 27, 2020

Valerie Muller
San Pablo Bay Pipeline Company LLC
3760 Kilroy Airport Way, Ste 3000
Long Beach, CA 90806

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: N-2224
Project Number: N-1193930

Dear Ms. Muller:

Enclosed for your review and comment is the District's analysis of San Pablo Bay Pipeline Company LLC's application for an Authority to Construct for the modification of an existing 20.0 MMBtu/hr pipeline oil heater to replace the existing burner with a new low NOx burner and to remove the 82 billion Btu/year heat input limit, located at 6801 Pete Miller Road, Gustine, CA.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period, 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. Dustin Brown of Permit Services at (559) 230-5932.

Sincerely,



Arnaud Marjollet
Director of Permit Services

AM:ddb

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

Samir Sheikh
Executive Director/Air Pollution Control Officer

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San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Modification of Pipeline Oil Heater

Facility Name: San Pablo Bay Pipeline Company LLC Date: April 17, 2020
Mailing Address: 3760 Kilroy Airport Way, Ste 3000 Engineer: Dustin Brown
Long Beach, CA 90806 Lead Engineer: Derek Fukuda
Contact Person: Valerie Muller
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Application #(s): N-2224-2-7
Project #: N-1193930
Deemed Complete: January 15, 2020

I. Proposal

San Pablo Bay Pipeline Company has submitted an Authority to Construct (ATC) application to modify an existing 20 MMBtu/hr fuel oil-fired pipeline heater (current Permit N-2224-2-6 included in Appendix B). The proposed modifications to this unit are summarized below:

- Replace the existing 20 MMBtu/hr fuel oil-fired burner with a new 20 MMBtu/hr North American, model 4213, natural gas-fired low NO_x burner. The new burner will be capable of achieving NO_x emissions of 7 ppmvd @ 3% O₂ and will bring this unit in to compliance with District Rules 4306 and 4320.
- Remove the non-compliant dormant operating status of this unit and bring it back up to full operational status.
- Remove the replacement status of this pipeline heater such that it can operate concurrently with the pipeline heater operating under permit N-2224-1 (reference conditions 12 and 13 from the current permit).
- Remove the annual heat input limit of 82 billion Btu's per year and allow the unit to operate full-time (8,760 hours per year).

The ATC application requesting the proposed modifications to this pipeline heater was originally submitted by Shell Pipeline Company LP. Shell Pipeline Company is the current owner and operator of the pipeline heater being modified within this project. Pursuant to correspondence received from Shell Pipeline Company, this facility is currently going through a transfer of ownership and they have requested that the ATC issued as a result of this project to be issued under the new owners name, San Pablo Bay Pipeline Company (reference transfer of ownership project N-1200808). Therefore, in accordance with their request, this evaluation and ATC will be processed and issued under the new owners name. The final ATC will not be issued until the transfer of ownership application has been processed and finalized by the District.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (8/15/19)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4305	Boilers, Steam Generators, and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators, and Process Heaters – Phase 3 (10/16/08)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4351	Boilers, Steam Generators and Process Heaters – Phase 1
Rule 4801	Sulfur Compounds (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)	
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines	

III. Project Location

The facility is located at 6801 Pete Miller Road in Gustine, CA. 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

San Pablo Bay Pipeline Company operates an oil pumping station at this location (Gustine Pump Station). This station receives petroleum products with API gravity varying from 11 degrees (heavier product) to 28 degrees (lighter product) from the Panoche Pump Stations and pumps the products north to the Tracy Pump Station via pipeline.

In order to keep the oil in the pipeline viscous enough to keep it easily flowing through the pipeline, it must be maintained at a certain temperature. If the temperature of the oil in the pipeline is too low, the pipeline heater being modified in this project will turn on and bring the temperature of the oil back up.

The applicant is proposing to replace the burner in the existing pipeline oil heater to lower the NO_x emissions down to 7 ppmv @ 3% O₂ such that the unit will be in compliance with District Rule 4320. No other physical equipment modifications are proposed.

V. Equipment Listing

Pre-Project Equipment Description:

N-2224-2-6: 20 MMBTU/HR NORTH AMERICAN MODEL #5131-250-H CRFA OIL HEATER; NON-COMPLIANT DORMANT EMISSIONS UNIT

Proposed Modification:

Replace the existing burner with a North American, model 4213, low NO_x burner, remove the non-compliant dormant status from this unit as it will now be operating in compliance with District Rules 4306 and 4320, remove the requirement that this unit can only operate when unit N-2224-1 is down for maintenance or repair, and increase the annual heat input limit from 82,000 MMBtu/year to 175,200 MMBtu/year (full time operation at 20 MMBtu/hr x 8,760 hours/year).

N-2224-2-7: MODIFICATION OF 20 MMBTU/HR NORTH AMERICAN MODEL #5131-250-H CRFA OIL HEATER; NON-COMPLIANT DORMANT EMISSIONS UNIT: REPLACE THE EXISTING BURNER WITH A NEW NORTH AMERICAN MODEL 4213 LOW NO_x BURNER, REMOVE DORMANT OPERATING STATUS, REMOVE REPLACEMENT UNIT FOR N-2224-1 OPERATING STATUS, AND REMOVE ANNUAL HEAT INPUT LIMIT

Post-Project Equipment Description:

N-2224-2-7: 20 MMBTU/HR NORTH AMERICAN MODEL #5131-250-H CRFA NATURAL GAS-FIRED PIPELINE OIL HEATER EQUIPPED WITH A NORTH AMERICAN MODEL 4213 LOW NO_x BURNER AND AN INDUCED FLUE GAS RECIRCULATION (FGR) SYSTEM

VI. Emission Control Technology Evaluation

Emissions from natural gas-fired boilers include NO_x, CO, VOC, PM₁₀, and SO_x.

NO_x is the major pollutant of concern when burning natural gas. NO_x formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_x). Due to the low fuel nitrogen content of natural gas, nearly all NO_x emissions are thermal NO_x. Formation of thermal NO_x is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

Low-NO_x burners reduce NO_x 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-NO_x burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NO_x. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

Flue gas recirculation (FGR) reduces NO_x emissions by recirculating a percentage of the exhaust gas back into the wind box. This reduces the oxygen concentration in the air-fuel mixture and regulates the combustion process, lowering the combustion temperature. The lowered availability of oxygen in conjunction with lowered combustion temperature reduces the formation of NO_x.

VII. General Calculations

A. Assumptions

- To streamline emission calculations, PM_{2.5} emissions are assumed to be equal to PM₁₀ emissions
- Prior to this modification, the unit was only fired on fuel oil (current permit limit)
- Prior to this modification, maximum operating schedule for this pipeline heater was 24 hours per day and up 82 billion Btu's per year, equivalent to 4,100 hours of operation per year (current permit limit)
- After this modification, this unit will only be fired on PUC-quality natural gas (proposed by the applicant)
- After this modification, the maximum operating schedule for this pipeline heater will be 24 hours/day and 8,760 hours/year (proposed by the applicant)
- Post-project natural gas heating value: 1,000 Btu/scf (District Practice)
- Post-project F-Factor for natural gas: 8,578 dscf/MMBtu corrected to 60°F (40 CFR 60, Appendix B)

B. Emission Factors

Pre-Project Emission Factors:

The current permit for this pipeline heater does not contain emission factors for any pollutant. Therefore, the following NO_x, CO, VOC, SO_x, and PM₁₀ emission factors for fuel oil combustion were taken from the last engineering evaluation performed for the modification to this oil fired pipeline heater under project N-1011026 and AP-42, Tables 1.3-1 through 1.3-3, May 2010 revision. The SO_x emission factor is based on a fuel sulfur content of 2.5%.

Pre-Project Fuel Oil Combustion Emission Factors		
Pollutant	lb/MMBtu	Source
NO _x	0.37	Project N-1011026
SO _x	2.62	
PM ₁₀	0.077	
CO	0.033	
VOC	0.0019	

Post-Project Emission Factors

The new replacement burner will only have the ability to combust natural gas. For the new burner, the emission factors for NO_x and CO were proposed by the applicant and burner manufacturer. The VOC emission factor is taken from AP-42. The PM₁₀ emission factor is taken from current District practice for natural gas fuel combustion. The SO_x emission factor is based on District Policy APR-1720. The emission factors and sources are summarized in the following table:

Post-Project Natural Gas Combustion Emission Factors			
Pollutant	lb/MMBtu	ppmv (@ 3% O ₂)	Source
NO _x	0.008	7	Proposed by Applicant
SO _x	0.00285		District Policy APR-1720
PM ₁₀	0.003	--	District Practice
CO	0.296	400	Proposed by Applicant
VOC	0.0055	--	AP-42 (07/98) Table 1.4-2

According to boiler manufacturers, low NO_x burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the emissions factors for this unit during startup and shutdown will be assumed to be the same as the steady state emission factors shown in the table above.

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Daily PE (PE1):

The pipeline oil heater has the potential to combust fuel oil for an entire day. Therefore, the NO_x, CO, VOC, PM₁₀ and SO_x daily PE values will be calculated using the pre-project emission factors listed above, the heat input rating of the burner, and the maximum hours of operation during any given day.

$$\text{PE (lb/day)} = \text{EF (lb/MMBtu)} \times \text{Burner Rating (MMBtu/hr)} \times 24 \text{ (hr/day)}$$

Pollutant	Emission Factor (lb/MMBtu)	Burner Rating (MMBtu/hr)	Operating Hours (hr/day)	Daily PE1 (lb/day)
NO _x	0.37	20.0	24	177.6
SO _x	2.62	20.0	24	1,257.6
PM ₁₀	0.077	20.0	24	37.0
CO	0.033	20.0	24	15.8
VOC	0.0019	20.0	24	0.9

Annual PE1:

The current permit for this pipeline oil heater contains an annual operating limit of 82 billion Btu's per year. Therefore, the annual PE values for NO_x, CO, VOC, PM₁₀ and SO_x will be calculated using the emission factors listed above and the annual heat input limit.

$$\text{PE (lb/year)} = \text{EF (lb/MMBtu)} \times \text{Annual Heat Input Limit (MMBtu/yr)}$$

Pollutant	Emission Factor (lb/MMBtu)	Heat Input Limit (MMBtu/yr)	Annual PE1 (lb/year)
NO _x	0.37	82,000	30,340
SO _x	2.62	82,000	214,840
PM ₁₀	0.077	82,000	6,314
CO	0.033	82,000	2,706
VOC	0.0019	82,000	156

2. Post-Project Potential to Emit (PE2)

Daily PE (PE2):

After this modification, the pipeline oil heater will have the potential to burn natural gas for an entire day. Therefore, the NO_x, CO, VOC, PM₁₀ and SO_x daily PE values will be calculated using the post-project emission factors listed above, the maximum heat input rating of the burner, and the maximum hours of operation during any given day.

$$\text{PE (lb/day)} = \text{EF (lb/MMBtu)} \times \text{Burner Rating (MMBtu/hr)} \times 24 \text{ (hr/day)}$$

Pollutant	Emission Factor (lb/MMBtu)	Burner Rating (MMBtu/hr)	Operating Hours (hr/day)	Daily PE2 (lb/day)
NO _x	0.008	20.0	24	3.8
SO _x	0.00285	20.0	24	1.4
PM ₁₀	0.003	20.0	24	1.4
CO	0.296	20.0	24	142.1
VOC	0.0055	20.0	24	2.6

Annual PE2:

After this modification, the applicant is not proposing to include an annual operating limits for this pipeline oil heater. Therefore, the NO_x, CO, VOC, PM₁₀ and SO_x annual PE values will be calculated using the post-project emission factors listed above, the maximum heat input rating of the burner, and the maximum hours of operation during any given year.

$$\text{PE (lb/year)} = \text{EF (lb/MMBtu)} \times \text{Burner Rating (MMBtu/hr)} \times 8,760 \text{ (hr/year)}$$

Pollutant	Emission Factor (lb/MMBtu)	Burner Rating (MMBtu/hr)	Operating Hours (hr/year)	Annual PE2 (lb/year)
NO _x	0.008	20.0	8,760	1,402
SO _x	0.00285	20.0	8,760	499
PM ₁₀	0.003	20.0	8,760	526
CO	0.296	20.0	8,760	51,859
VOC	0.0055	20.0	8,760	964

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.

The SSPE1 values listed in the table below for permits N-2224-1-6, '-3-0, and '-4-0 were calculated in Appendix E and the values for permit N-2224-2-6 were calculated in section VII.C of this document above.

SSPE1 (lb/year)					
Permit Unit	NO_x	SO_x	PM₁₀	CO	VOC
N-2224-1-6	1,927	499	1,332	41,698	964
N-2224-2-6	30,340	214,840	6,314	2,706	156
N-2224-3-0	0	0	0	0	5,410
N-2224-4-0	0	0	0	0	5,410
SSPE1	32,267	215,339	7,646	44,404	11,940

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	PM₁₀	CO	VOC
N-2224-1-6	1,927	499	1,332	41,698	964
N-2224-2-7	1,402	499	526	51,859	964
N-2224-3-0	0	0	0	0	5,410
N-2224-4-0	0	0	0	0	5,410
SSPE2	3,329	998	1,858	93,557	12,748

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	PM₁₀	PM_{2.5}	CO	VOC
SSPE1	32,267	215,339	7,646	7,646	44,404	11,940
SSPE2	3,329	998	1,858	1,858	93,557	12,748
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Post-Project Major Source?	No	No	No	No	No	No

Note: PM_{2.5} assumed to be equal to PM₁₀

As seen in the table above, the facility is an existing Major Source for NO_x and SO_x emissions. However, after this modification, the facility will no longer be a Major Source for any pollutant.

Rule 2410 Major Source Determination:

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)						
	NO₂	VOC	SO₂	CO	PM	PM₁₀
Estimated Facility PE before Project Increase	16	6	108	22	4	4
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

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

Pursuant to District Rule 2201, BE = PE1 for:

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

otherwise,

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

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE = PE1.

As calculated in Section VII.C.1 above, PE1 is summarized in the following table:

BE (lb/year)						
	NO _x	SO _x	PM ₁₀	PM _{2.5}	CO	VOC
N-2224-2-6	30,340	214,840	6,314	6,314	2,706	156

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 any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

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

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification.

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
- VOC

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	0.7	0.5	0.2	25.9	0.3	0.3
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

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. Detailed QNEC calculations are included in Appendix F.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, 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 Adjusted Increase in Permitted Emissions (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 discussed above, the applicant is proposing to modify an existing oil pipeline heater in this project. However, since the modification will remove the replacement unit operating status such that it will be able to operate at the same time as unit N-2224-1 and is also removing the 82 billion Btu per year heat input limit, the District will consider this unit to be operating under a new class and category of source (e.g. full time versus limited replacement unit). Therefore, it will be treated as a new emission unit for BACT purposes within this project.

As seen in Section VII.C.2 above, the PE2 for this natural gas-fired pipeline heater is greater than 2 lb/day for NO_x, CO, and VOC emissions. BACT is triggered for NO_x and VOC only since the PEs are 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 above, the applicant is proposing to modify an existing pipeline oil heater within this project. However, due to the changes that are being proposed for this pipeline oil heater, the unit is being considered as a new emission unit for BACT purposes. Therefore, there are no modified emissions units associated with this project and 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 not constitute an SB 288 and/or Federal Major Modification for any pollutant. Therefore BACT is not triggered for any pollutant.

2. BACT Guideline

Per District Policy APR 1305, Section IX, “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.” For source categories or classes covered in the BACT Clearinghouse, relevant information under each of the steps may be simply cited from the Clearinghouse without further analysis.

The District’s current BACT Clearinghouse Guideline 1.8.5, covers process heaters rated at less than or equal to 20.0 MMBtu/hr. However, BACT Guideline 1.8.5 has been rescinded and is no longer an active guideline. Therefore, a project specific top-down BACT analysis will be performed for the purposes of this project.

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 Appendix C), BACT has been satisfied with the following:

NO_x: 7 ppmv @ 3% O₂
VOC: Natural Gas-Firing

The following conditions will be included on the ATC as a mechanism to assure continued compliance with the BACT requirements:

- The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]
- Emissions rates from the natural gas-fired unit shall not exceed any of the following limits: 7 ppmv NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu, 0.00285 lb-SO_x/MMBtu, 0.003 lb-PM₁₀/MMBtu, 400 ppmv CO @ 3% O₂ or 0.296 lb-CO/MMBtu, or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, 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	3,329	998	1,858	93,557	12,748
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

- New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
- Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
- Any project which results in the offset thresholds being surpassed,
- Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
- 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 does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not 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. There are no new emissions units associated with this project. Therefore public noticing is not required for this project for PE > 100 lb/day.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO _x	32,267	3,329	20,000 lb/year	No
SO _x	215,339	998	54,750 lb/year	No
PM ₁₀	7,646	1,858	29,200 lb/year	No
CO	44,404	93,557	200,000 lb/year	No
VOC	11,940	12,748	20,000 lb/year	No

As demonstrated above, there were no offset 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	3,329	32,267	-28,938	20,000 lb/year	No
SO _x	998	215,339	-214,341	20,000 lb/year	No
PM ₁₀	1,858	7,646	-5,788	20,000 lb/year	No
CO	93,557	44,404	49,153	20,000 lb/year	Yes
VOC	12,748	11,940	808	20,000 lb/year	No

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

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for an SSIPE of CO emissions in excess of 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website 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:

- The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]
- Emissions shall not exceed any of the following limits: 7 ppmvd NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu, 400 ppmvd CO @ 3% O₂ or 0.296 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

E. Compliance Assurance

1. Source Testing

This pipeline oil heater is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, and District Rule 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5 MMBtu/hr*. Source testing requirements, in accordance with these rules will be discussed in more detail in the Rule 4320 compliance section of this evaluation below.

2. Monitoring

This pipeline oil heater is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, and District Rule 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5 MMBtu/hr*. Monitoring requirements, in accordance with these rules will be discussed in more detail in the Rule 4320 compliance section of this evaluation below.

3. Recordkeeping

This pipeline oil heater is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, and District Rule 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5 MMBtu/hr*. Recordkeeping, in accordance with these rules will be discussed in more detail in the Rule 4320 compliance section of this evaluation below.

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

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

Since this facility's post-project potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 2530 Federally Enforceable Potential to Emit

The purpose of this rule is to restrict the emissions of a stationary source so that the source may elect to be exempt from the requirements of Rule 2520. Prior to this project, this facility was a major source for NO_x and SO_x emissions and is currently utilizing the exemption offered by Rule 2530 to not need to obtain a Title V operating permit. Pursuant to Rule 2530, since this facility has elected exemption from the requirements of Rule 2520 by ensuring actual emissions from the stationary source in every 12-month periods to not exceed the following: ½ the major source thresholds for NO_x, VOCs, CO, and PM₁₀; 50 tons per year SO₂; 5 tons per year of a single HAP; 12.5 tons per year of any combination of HAPs; 50 percent of any lesser threshold for a single HAP as the EPA may establish by rule; and 50 percent of the major source threshold for any other regulated air pollutant not listed in Rule 2530.

However, after this modification, this facility will no longer have a potential to emit that is greater than the major source threshold for any pollutant. Therefore, they will no longer need to utilize the exemption that Rule 2530 provides and all Rule 2530 referenced recordkeeping conditions can be administratively removed from all of their permits. The following condition will be included on the ATC to assure that the facility is no longer required to maintain records in accordance with Rule 2530:

- *Upon implementation of the modification and startup of the equipment authorized by this Authority to Construct (ATC), this facility will no longer be a major source for any pollutant and all District Rule 2530 recordkeeping requirements shall be removed from all permits to operate. [District Rules 2201 and 2530]*

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 Steam Generators between 10 MMBtu/hr and 100 MMBtu/hr (post-6/9/89 construction, modification or, reconstruction).

The unit being modified in this project is a pipeline oil heater. Oil is heated directly by the low NO_x burner without the use of water or steam. Therefore, this unit is not a steam generating unit and Subpart Dc does not apply to this pipeline oil heater.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63. However, no subparts of 40 CFR Part 61 or 40 CFR Part 63 apply to natural gas-fired pipeline heaters.

Rule 4101 Visible Emissions

Rule 4101 states that 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 pipeline heater will be fired solely on natural gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. The following condition will be included on the ATC as a mechanism to assure ongoing 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

Rule 4102 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. The following condition will be added to the permit to further assure compliance with this rule.

- 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 or equal to one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was less than or equal to one. Therefore, no further analysis is required to determine the impact from this project and compliance with the District's Risk Management Policy is expected.

Rule 4201 Particulate Matter Concentration

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

The maximum particulate matter concentration for this natural gas-fired pipeline heater at dry standard conditions can be calculated as follows:

F-Factor: 8,578 dscf/MMBtu at 60 °F

PM₁₀ Emission Factor: 0.003 lb-PM₁₀/MMBtu (From Section VII.B)

Percentage of PM as PM₁₀ in Exhaust: 100%

$$\text{Grain Loading (GL)} = \left(\frac{0.003 \text{ lb} - \text{PM}}{\text{MMBtu}} \times \frac{7,000 \text{ grain}}{\text{lb} - \text{PM}} \right) \div \left(\frac{8,578 \text{ ft}^3}{\text{MMBtu}} \right)$$

$$\text{GL} = 0.002 \text{ grain/dscf} < 0.1 \text{ grain/dscf}$$

Therefore, the following condition will be listed on the permit as a mechanism to ensure compliance:

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

District Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO₂, NO₂, 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 LPG/natural gas combustion are less than 1 μm in diameter.

District Rule 4301 Limits			
Pollutant	NO ₂	Total PM	SO ₂
N-2224-2-7 (lb/hr)	0.17	0.06	0.057
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

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

This unit is natural gas-fired with a maximum heat input of 20.0 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* and District Rule 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr*.

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

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

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

This unit is natural gas-fired with a maximum heat input of 20.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3*.

In addition, the unit is also subject to District Rule 4320, *Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 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 requirements of District Rule 4306.

Therefore, compliance with District Rule 4306 requirements is expected and no further discussion is required.

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

This unit is natural gas-fired with a maximum heat input of 20.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4320, the unit is subject to District Rule 4320.

Section 5.2, NO_x and CO Emissions Limits

Section 5.2 requires that except for units subject to Sections 5.3, NO_x and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen.

With a maximum heat input of 20.0 MMBtu/hr, the applicable NO_x emission limit category is listed in Section 5.2, Table 1, Category A, from District Rule 4320. On and after October 1, 2008, units shall not be operated in a manner to which exceeds a carbon monoxide (CO) emissions limit of 400 ppmv.

Rule 4320 Emissions Limits		
Category	NO _x Limits	CO Limits
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 @ 3% O ₂
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	400 ppmv @ 3% O ₂

The proposed unit is subject to Category A of the emission limits specified in Table 1 of Section 5.2 as this unit is not operated as a low use unit and is not located at an oilfield, refinery or wastewater treatment plant. The applicant has proposed the following emission limits:

the proposed NO_x emission factor is 7 ppmvd @ 3% O₂ (0.008 lb/MMBtu), and
the proposed CO emission factor is 400 ppmvd @ 3% O₂ (0.296 lb/MMBtu)

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

The following condition will be included on the permit to assure continued compliance with the NO_x and CO requirements of this rule:

- Emissions shall not exceed any of the following limits: 7 ppmvd NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu; 0.00285 lb-SO_x/MMBtu; 0.003 lb-PM₁₀/MMBtu, 400 ppmvd CO @ 3% O₂ or 0.296 lb-CO/MMBtu; or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

Section 5.3, Annual Fee Calculation

Annual Fees are required if the unit will not be meeting the emission limits in Section 5.2 of this rule. Since the proposed pipeline heater will meet the emissions limits of Section 5.2, the annual fee requirements are not applicable.

Section 5.4, Particulate Matter Control Requirements

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

1. Fire the boiler exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;
2. Limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet;
3. Install and properly operate an emission control system that reduces SO₂ emissions by at least 95% by weight; or limit exhaust SO₂ to less than or equal to 9 ppmv corrected to 3.0% O₂;

The facility has proposed that the pipeline heater will be fired exclusively on PUC-quality natural gas. Therefore, the requirements of this section will be satisfied. The following condition will assure continued compliance:

- The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]

Section 5.5, Low Use

Section 5.5 specifies requirements for units with maximum annual heat input limits of less than 1.8 billion Btu's per calendar year. San Pablo Bay Pipeline Company is proposing to operate this pipeline heater as a full time unit with a heat input of greater than 1.8 billion Btu's per calendar year. Therefore, the proposed unit is not subject to the requirements of this section.

Section 5.6, Startup and Shutdown Provisions

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

According to the burner manufacturer, low NO_x burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated steady state emission factor following startup, this unit will be subject to the applicable emission limits of Section 5.2 at all times and the boiler will not utilize the startup and shutdown provisions specified within this section.

Section 5.7, Monitoring Provisions

Section 5.7.1 requires that permit units subject to District Rule 4320, Section 5.2 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_x, CO and O₂, or install and maintain APCO-approved alternate monitoring.

The applicant has proposed to use the pre-approved alternate monitoring scheme A (pursuant to District Policy SSP-1105), which requires that monitoring of NO_x, CO, and O₂ 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 listed on the permit in order to assure compliance with the requirements of the proposed alternate monitoring plan:

- The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306 and 4320]
- If either the NO_x or CO concentrations corrected to 3% O₂, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]

- 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]
- The permittee shall maintain records of: (1) the date and time of NO_x, CO, and O₂ measurements, (2) the O₂ concentration in percent and the measured NO_x 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]

Sections 5.7.2 and 5.7.3 specify monitoring requirements for units that are subject to the low use requirements specified in Section 5.5. As discussed above, the proposed boiler is not subject to the low use requirements of Section 5.5. Therefore, the requirements of Sections 5.7.2 and 5.7.3 are not applicable to this unit.

Section 5.7.4 allows units operated at seasonal sources and subject to 40 CFR 60 Subpart Db to install a parametric monitoring system in lieu of a CEMS. The process heater being modified in this project is not operated at a seasonal source. Therefore, this unit is not subject to the requirements of this section.

Section 5.7.6 outlines requirements for monitoring SO_x emissions. The following condition will be listed on the permit in order to ensure compliance with the requirements:

- 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]

Section 5.8, Compliance Determination

Section 5.8.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. 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 listed on the permits as follows:

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

Section 5.8.2 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. 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 condition will be listed on the permit as follows:

- All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [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 NO_x analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following previously listed permit condition will be on the permit as follows:

- 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 condition will be listed on the permit as follows:

- 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 upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

The following condition will be listed on the permits as a mechanism to assure continued compliance:

- 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 and 4320]

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

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

Section 6.1.4 requires that the operator of a unit with startup or shutdown provisions keep records of the duration of the startup or shutdowns. The facility has not proposed the use of startup and shutdown provisions, thus, the requirements of this section do not apply to these units.

Section 6.1.5 requires that the operator of a unit fired on liquid fuel during PUC-quality natural gas curtailment periods record the sulfur content of the fuel, amount of fuel used, and duration of the natural gas curtailment period. The facility has not proposed the use of curtailment fuels; therefore, the requirements of this section do not apply to these units.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Test Methods		
Pollutant	Units	Test Method Required
NO _x	ppmv	EPA Method 7E or ARB Method 100
NO _x	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O ₂	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following conditions will be listed on the permits as a mechanism to assure continued compliance:

- 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]
- NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306 and 4320]
- CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306 and 4320]
- Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306 and 4320]

Section 6.3, Compliance Testing

Section 6.3.1 requires that these units be tested to determine compliance with the applicable requirements of section 5.2 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months. Since the applicant is proposing to install a new burner as a part of the proposed project, initial source testing within 60 days of startup will be required.

The following conditions will be listed on the permits to assure continued compliance with this section:

- Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, 4306 and 4320]
- Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306 and 4320]
- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4320.

The proposed units will be in compliance with the emissions limits listed in table 1, Section 5.2 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4320. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator of steam generator must be in compliance with both the ATC deadline and compliance deadlines listed in Table 1 of Section 5.2.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.2 of this rule, and periodic monitoring and source testing as required by District Rule 4320. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4320, are satisfied. No further discussion is required.

Conclusion

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

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

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. The facility in this project is not a NO_x Major Source; therefore, the provisions of this rule do not apply.

Rule 4801 Sulfur Compounds

Section 3.1 states that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding a concentration of two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO₂) at the point of discharge on a dry basis averaged over 15 consecutive minutes.

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

$$\text{Volume SO}_2 = \frac{n RT}{P}$$

With:

N = moles SO₂

T (Standard Temperature) = 60°F = 520°R

P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}}$

EPA F-Factor: 8,578 dscf/MMBtu at 60 °F

$$\frac{0.00285 \text{ lb} - \text{SO}_x}{\text{MMBtu}} \times \frac{\text{MMBtu}}{8,578 \text{ dscf}} \times \frac{1 \text{ lb} - \text{mol}}{64 \text{ lb}} \times \frac{10.73 \text{ psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot ^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7 \text{ psi}} \times \frac{1,000,000 \text{ parts}}{\text{million}} = \frac{2.0 \text{ parts}}{\text{million}}$$

$$\text{Sulfur Concentration} = \frac{2.0 \text{ parts}}{\text{million}} < 2,000 \text{ ppmv (or 0.2\%)}$$

Therefore, compliance with District Rule 4801 requirements is expected.

California Health & Safety Code 42301.6 (School Notice)

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

California Environmental Quality Act (CEQA)

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

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

Greenhouse Gas (GHG) Significance Determination

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

On December 17, 2009, the District's Governing Board adopted a policy, APR 2005, *Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency*, for addressing GHG emission impacts when the District is Lead Agency under CEQA and approved the District's guidance document for use by other agencies when addressing GHG impacts as lead agencies under CEQA. Under this policy, the District's determination of significance of project-specific GHG emissions is founded on the principal that projects with GHG emission reductions consistent with AB 32 emission reduction targets are considered to have a less than significant impact on global climate change. Consistent with District Policy 2005, projects complying with an approved GHG emission reduction plan or GHG mitigation program, which avoids or substantially reduces GHG emissions within the geographic area in which the project is located, would be determined to have a less than significant individual and cumulative impact for GHG emission.

The California Air Resources Board (ARB) adopted a Cap-and-Trade regulation as part one of the strategies identified for AB 32. This Cap-and-Trade regulation is a statewide plan, supported by a CEQA compliant environmental review document, aimed at reducing or mitigating GHG emissions from targeted industries. Facilities subject to the Cap-and-Trade regulation are subject to an industry-wide cap on overall GHG emissions. Any growth in emissions must be accounted for under that cap such that a corresponding and equivalent reduction in emissions must occur to allow any increase. Further, the cap decreases over time, resulting in an overall decrease in GHG emissions.

Under District policy APR 2025, *CEQA Determinations of Significance for Projects Subject to ARB's GHG Cap-and-Trade Regulation*, the District finds that the Cap-and-Trade is a regulation plan approved by ARB, consistent with AB32 emission reduction targets, and supported by a CEQA compliant environmental review document. As such, consistent with District Policy 2005, projects complying with Cap-and-Trade requirements are determined to have a less than significant individual and cumulative impact for GHG emissions.

The GHG emissions increases associated with this project result from the combustion of fossil fuel(s), other than jet fuel, delivered from suppliers subject to the Cap-and-Trade regulation. Therefore, as discussed above, consistent with District Policies APR 2005 and APR 2025, the District concludes that the GHG emissions increases associated with this project would have a less than significant individual and cumulative impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing or former use. Furthermore, the District determined that the activity will not have a significant effect on the environment. Therefore, the District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

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 criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. 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 NSR Public Noticing period, issue ATC N-2224-2-7 subject to the permit conditions on the attached draft ATC in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
N-2224-2-7	3020-02-H	20 MMBtu/hr Heater	\$1,238

Appendixes

- A: Draft ATC N-2224-2-7
- B: Current Permit to Operate N-2224-2-6
- C: Top-Down BACT Analysis for NO_x and VOC Emissions
- D: Risk Management Review Summary
- E: Potential to Emit Calculations for Units N-2224-1-6, '-3-0, and '-4-0
- F: QNEC Calculations

APPENDIX A

Draft ATC N-2224-2-7

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: N-2224-2-7

LEGAL OWNER OR OPERATOR: SAN PABLO BAY PIPELINE COMPANY LLC

MAILING ADDRESS: 3760 KILROY AIRPORT WAY, SUITE 300
LONG BEACH, CA 90806

LOCATION: GUSTINE PUMP STATION
6801 PETE MILLER RD
GUSTINE, CA 95322

EQUIPMENT DESCRIPTION:

MODIFICATION OF 20 MMBTU/HR NORTH AMERICAN MODEL #5131-250-H CRFA OIL HEATER; NON-COMPLIANT DORMANT EMISSIONS UNIT: REPLACE THE EXISTING BURNER WITH A NEW NORTH AMERICAN MODEL 4213 LOW NOX BURNER, REMOVE DORMANT OPERATING STATUS, REMOVE REPLACEMENT UNIT FOR N-2224-1 OPERATING STATUS, AND REMOVE ANNUAL HEAT INPUT LIMIT

CONDITIONS

1. Upon implementation of the modification and startup of the equipment authorized by this Authority to Construct (ATC), this facility will no longer be a major source for any pollutant and the District Rule 2530 recordkeeping requirements shall be removed from all permits to operate. [District Rules 2201 and 2530]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
6. {4355} The unit shall only be fired on PUC-quality natural gas. [District Rules 2201 and 4320]
7. Emissions rates from the natural gas-fired unit shall not exceed any of the following limits: 7 ppmv NOx @ 3% O2 or 0.008 lb-NOx/MMBtu, 0.00285 lb-SOx/MMBtu, 0.003 lb-PM10/MMBtu, 400 ppmv CO @ 3% O2 or 0.296 lb-CO/MMBtu, or 0.0055 lb-VOC/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

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

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

N-2224-2-7 : Apr 27 2020 9:53AM -- BROWND : Joint Inspection NOT Required

Northern Regional Office • 4800 Enterprise Way • Modesto, CA 95356-8718 • (209) 557-6400 • Fax (209) 557-6475

8. {4315} The permittee shall monitor and record the stack concentration of NO_x, CO, and O₂ at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]
9. {4316} If either the NO_x or CO concentrations corrected to 3% O₂, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]
10. {4317} 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]
11. {4318} The permittee shall maintain records of: (1) the date and time of NO_x, CO, and O₂ measurements, (2) the O₂ concentration in percent and the measured NO_x 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]
12. {4344} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, 4306, and 4320]
13. {4345} Source testing to measure NO_x and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]
14. {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]
15. {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]
16. {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]
17. {4346} NO_x emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
18. {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
19. {4348} Stack gas oxygen (O₂) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

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CONDITIONS CONTINUE ON NEXT PAGE

20. {4352} 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]
21. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
22. {4356} 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]
23. All records shall be maintained and retained on-site for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

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APPENDIX B

Current Permit to Operate N-2224-2-6

San Joaquin Valley Air Pollution Control District

PERMIT UNIT: N-2224-2-6

EXPIRATION DATE: 08/31/2022

EQUIPMENT DESCRIPTION:

20 MMBTU/HR NORTH AMERICAN MODEL #5131-250-H CRFA OIL HEATER; NON-COMPLIANT DORMANT EMISSIONS UNIT

PERMIT UNIT REQUIREMENTS

1. The permittee shall not emit more than one half of the major source threshold based on a rolling 12-month summary of actual NOx emissions. [District Rule 2530, 6.1]
2. The permittee shall maintain a record of the rolling 12-month summary of actual emissions from permitted operations. This record shall be kept on site and made available to the District upon request. [District Rule 2530, 6.1]
3. Operation of the unit is not authorized until modifications are made to comply with District Rules as authorized by an Authority to Construct. [District Rule 2010]
4. The fuel line shall be physically disconnected from the unit. (Adjust as necessary) [District Rule 2080]
5. While dormant, normal source testing shall not be required. [District Rule 2080]
6. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
7. 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]
8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
9. The fuel oil usage for this oil heater shall be less than 82 billion BTUs per calendar year. [District Rule 4305]
10. The unit shall be tuned in accordance with District Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters) at least once each calendar year in which the boiler operates. [District Rule 4305]
11. This unit shall be equipped with a non-resettable totalizing mass or volumetric fuel flow meter which measures the quantity of fuel oil consumed by this unit, or the cumulative annual fuel oil usage of this unit shall be verified by other District approved methods in accordance with Rule 4305. [District Rule 4305]
12. This unit shall only be operated when the primary unit permitted under N-2224-1 is not operating because of breakdown or maintenance. [District Rule 4305]
13. Simultaneous operation of this replacement standby unit and the primary unit permitted under N-2224-1 shall not occur except during start-up or shutdown of the primary unit. [District Rule 4305]
14. Records of the amount and type of fuel consumed and cumulative heat input into the unit on a monthly basis shall be maintained on the premises at all times. Records shall be kept in accordance with District Rule 4305 (Boilers, Steam Generators, & Process Heaters). [District Rule 4305]
15. All records shall be retained for a minimum of 5 years, and shall be made available for District inspection upon request. [District Rule 1070]
16. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

These terms and conditions are part of the Facility-wide Permit to Operate.

APPENDIX C

Top-Down BACT Analysis for NO_x and VOC Emissions

Top-Down BACT Analysis for 20 MMBtu/hr Natural Gas-Fired Process Heater (Oil Heater)

The District does not currently have an approved BACT Guideline for this source category. The District's BACT Clearinghouse previously included guideline 1.8.5, which applied to non-refinery process heaters that were rated at equal to or less than 20 MMBtu/hr. However, guideline 1.8.5 has been rescinded and is currently not an active guideline. Therefore, a project-specific BACT analysis is required for the proposed modification of the 20 MMBtu/hr pipeline oil process heater.

1. BACT Analysis for NO_x Emissions:

a. Step 1 - List all control technologies

- i. The District adopted District Rule 4320 on October 16, 2008. District Rule 4320 includes a NO_x emission limit of 9 ppm @ 3% O₂ for boilers, steam generators and process heaters with heat input ratings equal to or less than 20 MMBtu/hr (reference Section 5.2, Table 1, Category A). This NO_x emission limit is being achieved by numerous units within the San Joaquin Valley. Therefore, this emission limit will be Achieved in Practice control technology for the purposes of this BACT analysis.
- ii. The District has also reviewed source test information for the actual NO_x emission rates that currently permitted process heaters with a rated heat input of equal to or less than 20.0 MMBtu/hr have been able to achieve. Based on the District's review of the available source test information that was found, the District has determined that at the time the processing of the application for this project began (when the application was deemed complete) the Achieved in Practice BACT limit for NO_x from oilfield process heaters with a rated heat input of 20.0 MMBtu/hr or less was 7 ppmvd NO_x @ 3% O₂ (0.008 lb-NO_x/MMBtu). A summary of the source tests reviewed by the District for this determination is shown in the table below (note: the table does not include source test results reviewed that exceeded 7 ppmvd NO_x @ 3% O₂).

Summary of Source Test Results for Oilfield Process Heaters Rated ≤ 20 MMBtu/hr						
Facility Name		Facility ID #		Location		
Shell Pipeline Company LP		C-1235		Panoche Pump Station, Fresno County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO _x Emission Limit (ppmvd @ 3% O ₂)	Source Test Date	Source Test Result (ppmvd @ 3% O ₂)	Control Equipment
C-1235-1-9	Oil Heater 1	20	9	4/18/2017	5.3	Ultra-Low NO _x Burner & FGR
C-1235-1-9	Oil Heater 1	20	9	4/4/2014	5.3	
C-1235-1-9	Oil Heater 1	20	9	4/18/2013	4.3	
Facility Name		Facility ID #		Location		
Phillips 66 Pipeline LLC		S-1520		Middlewater Pump Station: Lost Hills, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO _x Emission Limit (ppmvd @ 3% O ₂)	Source Test Date	Source Test Result (ppmvd @ 3% O ₂)	Control Equipment
S-1520-7-0	Heater B1	14.6	9	6/7/2018	7.86	Low NO _x Burner
S-1520-7-0	Heater B1	14.6	9	6/7/2017	7.4	
Facility Name		Facility ID #		Location		
Phillips 66 Pipeline LLC		S-1521		McKittrick Pump Station: McKittrick, Kern County, CA		

Summary of Source Test Results for Oilfield Process Heaters Rated ≤ 20 MMBtu/hr						
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO _x Emission Limit (ppmvd @ 3% O ₂)	Source Test Date	Source Test Result (ppmvd @ 3% O ₂)	Control Equipment
S-1521-2-6	Heater B2	11.72	9	3/11/2018	6.16	Ultra-Low NO _x Burner & FGR
S-1521-2-6	Heater B2	11.72	9	3/10/2015	6.43	
S-1521-13-0	Heater B1	8.165	9	6/14/2018	7.62	Low NO _x Burner & FGR
S-1521-13-0	Heater B1	8.165	9	6/7/2017	8.19	
Facility Name		Facility ID #		Location		
Shell Pipeline Company LP		S-3373		Griffith Station: Bakersfield, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO _x Emission Limit (ppmvd @ 3% O ₂)	Source Test Date	Source Test Result (ppmvd @ 3% O ₂)	Control Equipment
S-3373-1-6	Griffith Htr	12.5	9	8/30/2017	6.36	Ultra-Low NO _x Burner & FGR
S-3373-1-6	Griffith Htr	12.5	9	8/30/2014	7.22	
S-3373-1-6	Griffith Htr	12.5	9	8/30/2013	6.52	
Facility Name		Facility ID #		Location		
Shell Pipeline Company LP		N-2224		Gustine Station: Bakersfield, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO _x Emission Limit (ppmvd @ 3% O ₂)	Source Test Date	Source Test Result (ppmvd @ 3% O ₂)	Control Equipment
N-2224-1-6	Gustine 1	20.0	9	5/13/2016	6.12	Low NO _x Burner & FGR
N-2224-1-6	Gustine 1	20.0	9	5/22/2013	7.2	
N-2224-1-6	Gustine 1	20.0	9	5/30/2012	7.06	

Based on the District's review of the available source test information that were found, the District has determined that units in this class and category have shown the ability to meet a NO_x limit of 7 ppm @ 3% O₂. Therefore, a NO_x emission limit of 7 ppm @ 3% O₂ will also be considered Achieved in Practice from oilfield process heaters with a rated heat input of 20.0 MMBtu/hr or less.

- iii. District Rule 4320 also contains an enhanced schedule option that allowed applicants additional time to meet the requirements of the rule. The enhanced schedule NO_x emission limit requirement is 6 ppmv @ 3% O₂. In addition, the applicant has provided information that ultra-low NO_x burners could potentially be capable of reaching emission levels as low as 6 ppm @ 3% O₂. Therefore, an ultra-low NO_x burner with NO_x emissions of 6 ppmvd NO_x @ 3% O₂ (0.007 lb-NO_x/MMBtu) has been identified as a Technologically Feasible BACT option for the proposed modification of the 20 MMBtu/hr oilfield process heater.
- iv. Additionally, greater NO_x reductions may be possible by retrofitting the existing 20 MMBtu/hr oilfield process heater with a Selective Catalytic Reduction (SCR) system; therefore, use of an SCR system will also be included as a Technologically Feasible BACT option for NO_x emissions from the oilfield process heater. It will be conservatively assumed that an SCR system can reduce emissions from the existing oilfield process heater to 3.5 ppmvd NO_x @ 3% O₂ (0.0042 lb-NO_x/MMBtu). At this emissions level, steady state (excluding startup and shutdown) NO_x emissions from the unit would be no greater than 2.0 lb/day (20 MMBtu/hr x 24 hr/day x 0.0042 lb-NO_x/MMBtu = 2.0 lb-NO_x/day); 2.0 lb/day is the threshold that typically must be exceeded to trigger BACT requirements for new and modified units.

Summary of Control Options to be Evaluated:

The following control technologies have been identified as BACT options for oilfield process heaters with a maximum heat input rating ≤ 20.0 MMBtu/hr:

- 1) 3.5 ppmvd NO_x @ 3% O₂ or 0.0042 lb-NO_x/MMBtu (Selective Catalytic Reduction (SCR) – Technologically Feasible)
- 2) 6 ppmvd NO_x @ 3% O₂ or 0.007 lb-NO_x/MMBtu (Ultra-Low NO_x Burner/Enhanced Rule 4320 Limit – Technologically Feasible)
- 3) 7 ppmvd NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu (Achieved in Practice)
- 4) 9 ppmvd NO_x @ 3% O₂ or 0.011 lb-NO_x/MMBtu (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1. However, two of the control options referenced in Step 1 above have been identified as achieved in practice. Therefore, the higher emitting, less stringent option of these two achieved in practice control options will be removed from consideration at this time for the purposes of this BACT analysis (9 ppmvd NO_x @ 3% O₂).

c. Step 3 - Rank Remaining Control Technologies by Control

Rank	Control Efficiency Or Emission Factor	Achieved-in-Practice
1	SCR – 3.5 ppmvd NO _x @3% O ₂	No
2	Ultra Low NO _x Burner – 6 ppmvd NO _x @ 3% O ₂	No
3	Low NO _x Burner – 7 ppmvd NO _x @ 3% O ₂	Yes

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effective analysis must be performed for all control options that have not been determined to be achieved in practice in the list from Step 3 above, in the order of their ranking, to determine the cost effective option with the lowest emissions.

District BACT Policy APR 1305 establishes annual cost thresholds for imposed control based upon the amount of pollutants reduced by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_x emission reductions is \$24,500 per ton of NO_x emissions reduced.

For the purposes of District cost effectiveness analysis, the amount of emissions reduced is defined as the emissions from the technologically feasible control option versus District Standard Emissions (DSE) from this class and category of operation. For new emission units, DSE are equal to the emissions level allowed by an applicable District rule once the final compliance date for the rule has passed. As discussed in this analysis above, District Rule 4320 requires the process heater to meet a NO_x emission limit of less than or equal to 9 ppm @ 3% O₂ (0.011 lb-NO_x/MMBtu).

$$\text{DSE} = 9 \text{ ppm @ 3\% O}_2 \text{ (0.011 lb-NO}_x\text{/MMBtu)}$$

Option 1: 3.5 ppmvd NO_x @ 3% O₂ or 0.0042 lb-NO_x/MMBtu (Selective Catalytic Reduction (SCR) – Technologically Feasible)

Capital Cost

This option will require installation of a new SCR system to control emissions from the existing oilfield process heater. The estimated capital cost for retrofitting the existing process heater with a new SCR system is taken from the May 19, 2017 budgetary price quote that R.F. MacDonald Co. provided for an SCR system for an existing 12.6 MMBtu/hr natural gas-fired boiler (ATC- N-164-26-0) that was recently re-permitted under Project N-1171741. It will be conservatively assumed that the cost of an SCR system for the 20 MMBtu/hr oilfield process heater will be the same as the cost for the 12.6 MMBtu/hr boiler. It will also be conservatively assumed that costs obtained in 2017 would only go up if costs were obtained in 2020 due to inflation.⁽¹⁾

Cost to Retrofit Process Heater with an SCR system (3.5 ppmvd @ 3% O₂): \$250,000

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase and installation of the SCR system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(1+i)^n]/[(1+i)^n - 1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$\begin{aligned} A &= [\$250,000 \times 0.1(1.1)^{10}]/[(1.1)^{10} - 1] \\ &= \mathbf{\$40,686/\text{year}} \end{aligned}$$

⁽¹⁾ http://www.bls.gov/data/inflation_calculator.htm: \$250,000 in May of 2017 would be estimated \$263,523 in 2020, due to inflation, an increase of slightly more than 5%.

NO_x Emission Reductions:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions will be used to calculate the emission reductions from Technologically Feasible BACT options.

The District Standard Emissions for NO_x emissions from the 20 MMBtu/hr process heater is the 9 ppmvd NO_x @ 3% O₂ or 0.011 lb-NO_x/MMBtu limit given in District Rule 4320, Section 5.2, Table 1, Category A – Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units. Therefore, the following NO_x emission factors will be used for this cost analysis:

District Standard Emissions: 0.011 lb-NO_x/MMBtu (9 ppmvd NO_x @ 3% O₂)

Technologically Feasible Option 1 (SCR): 0.0042 lb-NO_x/MMBtu (3.5 ppmvd NO_x @ 3% O₂)

Emission Reductions:

NO_x Emission Reductions (9 ppmvd @ 3% O₂ → 3.5 ppmvd @ 3% O₂)

$(0.011 \text{ lb-NO}_x/\text{MMBtu} - 0.0042 \text{ lb-NO}_x/\text{MMBtu}) \times 20.0 \text{ MMBtu/hr} \times 8,760 \text{ hour/year}$

NO_x Emission Reductions = 1,191 lb-NO_x/year (0.60 ton-NO_x/year)

Cost of NO_x Emission Reductions

Cost of reductions = $(\$40,686/\text{year}) / (0.60 \text{ ton-NO}_x/\text{year})$
= **\$68,322/ton of NO_x reduced**

The analysis above demonstrates that the annualized capital cost for retrofitting the existing 20 MMBtu/hr pipeline oil heater alone, not including any annual operating costs, results in costs for this control option that exceed the District's BACT Cost Effectiveness Threshold for NO_x of \$24,500/ton. Therefore, this option is not cost-effective and will not be required for the proposed project.

Option 2: 6 ppmvd NO_x @ 3% O₂ or 0.007 lb-NO_x/MMBtu (Ultra-Low NO_x Burner – Technologically Feasible)

Capital Cost

This option will require installation of a new ultra-low NO_x burner. The estimated capital cost for retrofitting the existing process heater with a new ultra-low NO_x burner capable of achieving 6 ppmvd @ 3% O₂ is taken from the November 1, 2019 budgetary price quote that Esys provided to the facility for retrofitting the burner.

Cost to Retrofit Process Heater with a new 6 ppmvd @ 3% O₂ Ultra-Low NO_x Burner:
\$267,061

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase and installation of the ultra-low NO_x burner will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(i+1)^n]/[(i+1)^n - 1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$\begin{aligned} A &= [\$267,061 \times 0.1 \times (1.1)^{10}]/[(1.1)^{10} - 1] \\ &= \mathbf{\$43,463/\text{year}} \end{aligned}$$

NO_x Emission Reductions:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions will be used to calculate the emission reductions from Technologically Feasible BACT options.

The District Standard Emissions for NO_x emissions from the 20 MMBtu/hr process heater is the 9 ppmvd NO_x @ 3% O₂ or 0.011 lb-NO_x/MMBtu limit given in District Rule 4320, Section 5.2, Table 1, Category A – Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units. Therefore, the following NO_x emission factors will be used for the cost analysis:

District Standard Emissions: 0.011 lb-NO_x/MMBtu (9 ppmvd NO_x @ 3% O₂)

Technologically Feasible Option 2 (Ultra-Low NO_x Burner): 0.007 lb-NO_x/MMBtu (6 ppmvd NO_x @ 3% O₂)

Emission Reductions:

NO_x Emission Reductions (9 ppmvd @ 3% O₂ → 6 ppmvd @ 3% O₂)

(0.011 lb-NO_x/MMBtu - 0.007 lb-NO_x/MMBtu) x 20.0 MMBtu/hr x 24 hr/day x 365 day/year

NO_x Emission Reductions = 701 lb-NO_x/year (0.35 ton-NO_x/year)

Cost of NO_x Emission Reductions

$$\begin{aligned}\text{Cost of Reductions} &= (\$43,643/\text{year})/(0.35 \text{ ton-NO}_x/\text{year}) \\ &= \mathbf{\$124,694/\text{ton of NO}_x \text{ reduced}}\end{aligned}$$

As shown above, the cost of the NO_x emission reductions for retrofitting the existing process heater with a new ultra-low NO_x burner capable of achieving 6 ppmvd @ 3% O₂ exceeds the \$24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost-effective and will not be required for the proposed project.

Option 3: 7 ppmvd NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu (Achieved in Practice)

The only remaining control option in step 3 above has been deemed AIP for this class and category of source and per the District BACT policy is required regardless of the cost. Therefore, a cost effectiveness analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NO_x from the 20 MMBtu/hr natural gas-fired pipeline oil heater is satisfied with the following: 7 ppmvd NO_x @ 3% O₂ or 0.008 lb-NO_x/MMBtu

The applicant has agreed to comply with a NO_x emission limit of 7 ppmvd NO_x @ 3% O₂. Therefore, the BACT requirements for NO_x emissions from the modification of the existing 20 MMBtu/hr pipeline oil heater will be satisfied.

2. BACT Analysis for VOC Emissions:

VOC emissions result from the incomplete combustion of various elements in the natural gas fuel.

a. Step 1 - Identify all control technologies

As discussed above, the SJVUAPCD BACT Clearinghouse previously contained guideline 1.8.5, which identified BACT requirements for process heaters rated at less than 20 MMBtu/hr as firing on natural gas fuel or propane as a backup fuel. The BACT guideline was rescinded due to the fact that the NO_x emission requirements of Rule 4320 were more stringent than the NO_x requirements specified in BACT guideline 1.1.1.

However, Rule 4320 does not specify any requirements for VOC emissions. In addition, District Rule 4320 Section 3.7 indicates that PUC-quality natural gas is a high methane gas with at least 80% methane by volume. Because PUC-quality natural gas is mostly composed of methane, an exempt non-VOC compound, combustion of natural gas generally does not result in significant VOC emissions.

Therefore, it will be assumed that the previous requirements specified within BACT guideline 1.8.5 remain valid and will be used as BACT for VOC emissions for the purposes of this project and will be set equal to the following:

- 1) Natural gas with LPG backup or propane fired

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

b. Step 2 - Eliminate technologically infeasible options

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

c. Step 3 - Rank remaining options by control effectiveness

- 1) PUC-Quality Natural Gas (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option is required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the process heater is the use of PUC-quality natural gas as fuel. The applicant has proposed to use only PUC-quality natural gas (regulated by the PUC or FERC) as fuel. Therefore, the BACT requirements for VOC emissions from the modification of the existing 20 MMBtu/hr pipeline oil heater will be satisfied.

APPENDIX D

Risk Management Review Summary

San Joaquin Valley Air Pollution Control District

Risk Management Review

To: Dustin Brown – Permit Services
From: Keanu Morin – Technical Services
Date: January 28, 2020
Facility Name: Shell Pipeline Company Lp
Location: Latitude: 37.252348; Longitude: -121.118109
Application #(s): N-2224-2-7
Project #: N-1193930

1. Summary

1.1 RMR

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
2-7	0.00	N/A ¹	N/A ¹	N/A ¹	No	No
Project Totals	0.00	N/A ¹	N/A ¹	N/A ¹		
Facility Totals	<1	0.00	0.00	0.00		

Notes:

1. Acute and Chronic Hazard Indices were not calculated for Unit 5 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

1.2 Proposed Permit Requirements

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

Unit # 2-7

1. No special requirements.

2. Project Description

Technical Services received a request on January 25, 2020 to perform a Risk Management Review (RMR) for the following:

- Unit -2-7: Shell Pipeline Company is proposing to modify an existing dormant 20.0 MMBtu/hr oil heater (PTO N-2224-2-6) by replacing the existing fuel oil-fired burner with a new natural gas-fired burner, removing the dormant status, and increasing the annual operation from 82 billion Btus per calendar year when fired on dual oil to a full time unit (8,760 hours/year) when fired on natural gas.

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices (Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emission factors for this unit were derived from data in the 1992 Radian Corporation report to WSPA.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed unit was less than 1.0 (see RMR Summary Table). Therefore, no further analysis was necessary.

The following parameters were used for the review:

Source Process Rates						
Unit ID	Process ID	Process Material	Process Units	Hourly Process Rate	Annual Process Rate	Receptor Distance (m)
2-7	1	Natural Gas	MMscf.	0.02	175.2	<1500

4. Conclusion

4.1 RMR

The cumulative prioritization score for the facility, including this project, 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.

5. Attachments

- A. Modeling request from the project engineer
- B. Additional information from the applicant/project engineer
- C. Prioritization score w/ toxic emissions summary
- D. Facility Summary

APPENDIX E

SSPE1 Calculations for Permits N-2224-1-6, '-3-0, and '-4-0

N-2224-1-6 (20 MMBtu/hr natural gas-fired pipeline heater):

This pipeline heater has the potential to generate NO_x, SO_x, PM₁₀, CO and VOC emissions. The current permit contains lb/MMBtu emission limits for all of these pollutants. Therefore, the annual PE for each pollutant can be calculated using the permitted emission limits, the maximum heat input rating of the pipeline heater and a worst-case operating schedule of 8,760 hours per year.

A. Emission Factors

Natural Gas Combustion Emission Factors		
Pollutant	Emission Factor (lb/MMBtu)	Source
NO _x	0.011	Current Permit
SO _x	0.00285	Current Permit
PM ₁₀	0.0076	Current Permit
CO	0.238	Current Permit
VOC	0.0055	Current Permit

B. Calculations

The current permit for this pipeline heater does not contain any annual operating limits. Therefore, the annual PE for each pollutant can be calculated using the permitted emission factors, the maximum heat input rating of the pipeline heater, and a worst-case operating schedule of 8,760 hours per year. A sample calculation for NO_x emissions is shown below

$$\text{Annual PE} = \text{Emission Factor (lb/MMBtu)} * \text{Burner Rating (MMBtu/hr)} \\ * \text{Operation (hours/year)}$$

$$\text{Annual PE} = 0.011 \text{ lb/MMBtu} \times 20 \text{ MMBtu/hr} \times 8,760 \text{ hours/year}$$

$$\text{Annual PE} = 1,927 \text{ lb-NO}_x/\text{year}$$

Annual PE for the Pipeline Heater	
Pollutant	Annual Emissions (lb/year)
NO _x	1,927
SO _x	499
PM ₁₀	1,332
CO	41,698
VOC	964

N-2224-3-0 and -4-0 (identical 126,000 gallon fixed roof emergency standby oil storage tanks):

These emergency standby oil storage tanks only have the potential to generate VOC emissions. The current permits for each of these storage tanks are identical and limit the maximum VOC emissions to 5,410 lb/year. Therefore, the annual emissions for each of these units will be set equal to the current permit limit and no further calculations are required.

Annual VOC PE = 5,410 lb/year

APPENDIX F

QNEC Calculations

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

$QNEC = PE2 - PE1$, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1, quarterly PE2 and quarterly PE1 can be calculated as follows (sample calculation for NO_x shown below):

$$\begin{aligned} PE2_{\text{quarterly}} &= PE2_{\text{annual}} \div 4 \text{ quarters/year} \\ &= 1,402 \text{ lb/year} \div 4 \text{ qtr/year} \\ &= 350.5 \text{ lb-NO}_x/\text{qtr} \end{aligned}$$

$$\begin{aligned} PE1_{\text{quarterly}} &= PE1_{\text{annual}} \div 4 \text{ quarters/year} \\ &= 30,340 \text{ lb/year} \div 4 \text{ qtr/year} \\ &= 7,585 \text{ lb-NO}_x/\text{qtr} \end{aligned}$$

Quarterly NEC [QNEC]			
Pollutant	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO _x	350.5	7,585	-7,234.5
SO _x	124.75	54,710	-54,585.25
PM ₁₀	131.5	1,578.5	-1,447.0
CO	12,964.75	676.5	12,288.25
VOC	241	39	202.0