CH2M HILL
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833
Tel 916-920-0300
Fax 916-920-8463

CH2MHILL

| DOCKET 09-AFC-2 | |
|---|---|
| DATE | FEB 22 2010 |
| RECD. | FEB 22 2010 |

February 22, 2010

383194.AP.PM

Ms. Felicia Miller
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: Almond 2 Power Plant (09-AFC-02)
Final Determination of Compliance

Dear Ms. Miller:

Attached please find 13 hard copies and 1 electronic copy on CD-ROM of the Almond 2 Power Plant's Final Determination of Compliance.

If you have any questions about this matter, please contact me at (916) 286-0249 or contact Susan Strachan at (530) 757-7038.

Sincerely,

CH2M HILL

Sarah Madams
AFC Project Manager

Attachment
cc: S. Strachan, Strachan Consulting
R. Baysinger, TID

# San Joaquin Valley
## AIR POLLUTION CONTROL DISTRICT

FEB 16 2010

Randy Baysinger
Turlock Irrigation District
P. O. Box 949
Turlock, CA 95381-0949

**RE: Notice of Final Determination of Compliance (FDOC)**
**Facility: Turlock Irrigation District (09-AFC-02)**
**Project Number: N-1091384**

Dear Mr. Baysinger:

Enclosed is the District's final determination of compliance (FDOC) for the installation of three identical 54.2 MW (each), nominal ISO rating, natural gas-fired, simple-cycle, peaking electric generation facility that will consist of General Electric's (GE) natural gas-fired aero-derivative LM6000 PG SPRINT combustion turbines equipped with GE's state-of-the-art single annular combustors rated at 523.2 MMBtu/hr (at ISO MW rating), all located at 4500 Crows Landing Road, Modesto, California. This letter serves as our notification of final action and enclosed is your copy of the FDOC.

Notice of the District's preliminary determination of compliance (PDOC) for this project was published on December 7, 2009. The changes made to the PDOC were in direct response to comments received from the applicant. Responses to the comments received for the PDOC are included in Attachment J of the attached FDOC evaluation. It is District practice to require an additional 30-day comment period for a project if changes result in a significant emissions increase that affects or modifies the original basis for approval. The changes made to the PDOC were minor and did not result significant emissions increase, or trigger additional public notification requirement. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Rupi Gill at (209) 557-6400.

Sincerely,

David Warner
Director of Permit Services

DW: JK/cm

Enclosures
cc: Nancy Matthews, Sierra Research
1801 J Street, Sacramento, CA 95811

Modesto Bee

## NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Turlock Irrigation District for the installation of three identical 54.2 MW (each), nominal ISO rating, natural gas-fired, simple-cycle, peaking electric generation facility that will consist of General Electric's (GE) natural gas-fired aero-derivative LM6000 PG SPRINT combustion turbines equipped with GE's state-of-the-art single annular combustors rated at 523.2 MMBtu/hr (at ISO MW rating), located at 4500 Crows Landing Road, Modesto, California..

All comments received following the District's preliminary decision on this project were considered. Changes were made to the determination of compliance evaluation in direct response to comments received from the applicant. The changes made were minor and did not significantly increase permitted emission levels or trigger additional public notification requirements.

The application review for Project #N-1091384 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 4800 ENTERPRISE WAY, MODESTO, CA 95356-8718.**

# FINAL DETERMINATION OF COMPLIANCE EVALUATION

## Turlock Irrigation District (Almond 2 Power Plant)
## California Energy Commission
## Application for Certification Docket #: 09-AFC-02

| | |
|---|---|
| **Facility Name:** | Turlock Irrigation District |
| **Mailing Address:** | P.O. Box 949<br>Turlock, CA 95381-0949 |
| **Contact Name:** | Randy Baysinger |
| **Telephone:** | (209) 883-8232 |
| **Fax:** | (209) 656-2142 |
| **E-Mail:** | rcbaysinger@tid.org |
| **Alternate Contact:** | Jeff Adkins, Consultant |
| **Telephone:** | (916) 444-6666 |
| **Fax:** | (916) 444-8373 |
| **E-Mail:** | jadkins@sierraresearch.com |
| **Alternate Contact:** | Nancy Matthews, Consultant |
| **Telephone:** | (916) 444-6666 |
| **Cell:** | (916) 444-8373 |
| **E-Mail:** | nmatthews@sierraresearch.com |
| **Engineer:** | Jagmeet Kahlon, Air Quality Engineer |
| **Lead Engineer:** | Rupi Gill, Permit Services Manager |
| **Date:** | February 10, 2010 |
| **District Project #:** | N-1091384 |
| **Permit #:** | N-3299-4-0, N-3299-5-0, N-3299-6-0 |
| **Submitted:** | March 25, 2009 |
| **Deemed Complete:** | May 21, 2009 |

# TABLE OF CONTENTS

## I. PROPOSAL

Turlock Irrigation District (TID) is requesting Authority to Construct permits (ATCs) for the installation of three identical 54.2 MW (each), nominal ISO rating, natural gas-fired, simple-cycle, peaking electric generation facility that will consist of General Electric's (GE) natural gas-fired aero derivative LM6000 PG SPRINT (SPRay INTercoling water injection for increased power output) Combustion Turbine Generators (CTG). Each CTG is equipped with GE's state-of-the-art single annular combustors rated at a combined heat input rate of 523.2 MMBtu/hr (at ISO rating). The exhaust from each CTG will be vented through its own Selective Catalytic Reduction (SCR) system for nitrogen oxide (NOx) emissions control, and through an oxidation catalyst to convert carbon monoxide (CO) into carbon dioxide ($CO_2$) gas.

TID has submitted an Application for Certification (AFC) to the California Energy Commission (CEC). Currently, this project is going through the licensing process led by the CEC. Pursuant to SJVAPCD Rule 2201, Section 5.8, the District is required to submit a Determination of Compliance (DOC) to the CEC within 240 days after acceptance of complete application. DOC is functionally equivalent to ATCs provided that the CEC approves the AFC and certificate granted by the CEC includes all conditions of the DOC. This document constitutes the DOC. CEC is the lead agency for determining California Environmental Quality Act (CEQA) requirements for this project.

Per TID, the project is not required to obtain Prevention of Significant Deterioration (PSD) permit from the EPA.

The District had received comments from the applicant on the Preliminary Determination of Compliance (PDOC). These comments are addressed as part of this project (Refer to Attachment J). No comments were made by the public, the CEC, the CARB, or the EPA Region 9 on this project.

## II. APPLICABLE RULES

| | |
|---|---|
| Rule 1080 | Stack Monitoring (12/17/92) |
| Rule 1081 | Source Sampling (12/16/93) |
| Rule 1100 | Equipment Breakdown (12/17/92) |
| Rule 2010 | Permits Required (12/17/92) |
| Rule 2201 | New and Modified Stationary Source Review Rule (9/21/06) |
| Rule 2520 | Federally Mandated Operating Permits (6/21/01) |
| Rule 2540 | Acid Rain Program (11/13/97) |
| Rule 2550 | Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/1998) |
| Rule 4001 | New Source Performance Standards (4/14/99)<br>40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines<br>40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines |
| Rule 4002 | National Emissions Standards for Hazardous Air Pollutants (5/18/00) |

| | |
|---|---|
| Rule 4101 | Visible Emissions (02/17/05) |
| Rule 4102 | Nuisance (12/17/92) |
| Rule 4201 | Particulate Matter Concentration (12/17/92) |
| Rule 4202 | Particulate Matter Emission Rate (12/17/92) |
| Rule 4301 | Fuel Burning Equipment (12/17/92) |
| Rule 4703 | Stationary Gas Turbines (9/20/07) |
| Rule 4801 | Sulfur Compounds (12/17/92) |
| Rule 8011 | General Requirements (8/19/04) |
| Rule 8021 | Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04) |
| Rule 8031 | Bulk Materials (8/19/04) |
| Rule 8041 | Carryout and Trackout (8/19/04) |
| Rule 8051 | Open Areas (8/19/04) |
| Rule 8061 | Paved and Unpaved Roads (8/19/04) |
| Rule 8071 | Unpaved Vehicle/Equipment Traffic Areas (9/16/04) |

California Health & Safety Code Section 41700 (Public Nuisance)
California Health & Safety Code Section 42301.6 (School Notice)
California Health & Safety Code Section 44300 (Air Toxic "Hot Spots")
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
40 CFR Part 51 Appendix S Requirements for $PM_{2.5}$

## III. PROJECT LOCATION

The proposed equipment will be located at 4500 Crows Landing Road, Modesto, California. There is no K-12 school within 1,000 feet of this location. Therefore, school notice, under California Health & Safety Code 42301.6 is not required.

## IV. PROCESS DESCRIPTION

CTG combustion air will flow through the inlet air filters, evaporative cooler and associated air inlet ductwork, be compressed in the CTG compressor section, and then enter the CTG combustion section. Natural gas fuel will be injected into the compressed air in the combustion section and the mixture is ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing the shaft to rotate that drives both the electrical generator and CTG compressor.

Flue gases due to combustion of natural gas fuel in the CTG burners will be vented through SCR system for NOx emissions control, and an oxidation catalyst for CO control.

CTGs can be operated 24 hr/day, 7 days/week and 52 weeks/year. CTG will be operated exclusively on natural gas fuel.

## V. EQUIPMENT LISTING

N-3299-4-0, '-5-0, '-6-0
54.2 MW NOMINAL (ISO) RATING SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM CONSISTING OF A 523.2 MMBTU/HR (AT NOMINAL ISO MW RATING) GENERAL ELECTRIC, AERO DERIVATIVE, MODEL LM6000 PG SPRINT, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH A WATER SPRAY PREMIXED COMBUSTION SYSTEM, AN OXIDATION CATALYST AND A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION

N-3299-4-0, '-5-0, '-6-0
TID has proposed to install GE's LM 6000PG CTGs with a state-of-the-art single annular combustors and SPRINT to control NOx formation. Each CTG will also be equipped with an SCR system with ammonia injection to further reduce the NOx emissions. SCR system selectively reduces $NO_X$ emissions by injecting ammonia ($NH_3$) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, $NH_3$, and $O_2$ react on the surface of the catalyst to form molecular nitrogen ($N_2$) and $H_2O$. SCR is capable of reducing over 90 percent $NO_X$ reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750°F. Exhaust gas temperatures greater than the upper limit (750°F) will cause $NO_X$ and $NH_3$ to pass through the catalyst un-reacted. $NH_3$ slip is proposed to be less than or equal to 10.0 ppmvd @ 15% $O_2$ over 24-hour rolling average basis.

CO is formed during the combustion process due to incomplete oxidation of the carbon in the fuel. CO formation can be limited by ensuring complete and efficient combustion of the fuel. CO emissions will be controlled using an oxidation catalyst. Oxidation catalyst uses a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide ($CO_2$). No reagents are used upstream of the catalyst. The catalyst is also somewhat effective for controlling VOC emissions by a similar chemical reaction to that of carbon monoxide.

TID has proposed to demonstrate compliance with the following emission rates after using water-injection, SCR and oxidation catalyst devices:

2.5 ppmvd NOx @ 15% $O_2$ on 1-hour rolling average basis
4.0 ppmvd CO @ 15% $O_2$ on 3-hour rolling average basis
2.0 ppmvd VOC @ 15% $O_2$ on 3-hour rolling average basis

The inlet air filters will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted into the atmosphere.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

Inlet air temperature and density directly affects turbine performance. Hotter and drier the inlet air temperature results in lower the efficiency of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air evaporative cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

## VII. GENERAL CALCULATIONS

### A. Assumptions

N-3299-4-0, '-5-0, '-6-0

1. The proposed hourly emission rates and the operating schedule are used in determining the potential emissions from each CTG.

2. Other assumptions will be stated as they are made.

### B. Emission Factors (EFs)

1. Pre-Project Emission Factors (EF1):

N-3299-4-0, '-5-0, '-6-0
The proposed emission units are new to the facility. Therefore, EF1 does not exist.

2. Post-Project Emission Factors (EF2):

N-3299-4-0, '-5-0, '-6-0
TID has proposed the following emission factors and hourly emission rates for the CTGs.

The expected heat input rate to each CTG would be 523.2 MMBtu/hr at average ambient temperature (60°F). The potential emissions at this heat input rate are referred as "base" emissions in the following table.

At low ambient temperature (30°F), the heat input rate to each CTG could be 554.9 MMBtu/hr. The potential emissions at this heat input rate are referred as "peak" emissions.

| NOx Emission Limits | | |
|---|---|---|
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 25.00 |
| Turbine, base/peak | 2.5 ppmvd @ 15% $O_2$, 1-hour rolling average period | 4.74 (base) |
| | | 5.02 (peak) |
| **CO Emission Limits** | | |
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 40.00 |
| Turbine, base/peak | 4.0 ppmvd @ 15% $O_2$ based on 3-hour rolling average period | 4.61 (base) |
| | | 4.89 (peak) |
| **VOC Emission Limits** | | |
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 2.00 |
| Turbine, base/peak | 2.0 ppmvd @ 15% $O_2$ based on 3-hour rolling average period | 1.32 (base) |
| | | 1.40 (peak) |
| **$NH_3$ Emission Limits** | | |
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 7.44 |
| Turbine, base/peak | 10.0 ppmvd @ 15% $O_2$ 24-hour rolling average period | 7.01 (base) |
| | | 7.44 (peak) |
| **$PM_{10}$ Emission Limits** | | |
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 2.50 |
| Turbine, base/peak | -- | 2.50 (base) |
| | | 2.50 (peak) |
| **$SO_x$ Emission Limits** | | |
| Category | Concentrations | PE (lb/hr) |
| Turbine, startups/shutdowns | -- | 1.56 |
| Turbine, base/peak | -- | 1.47 (base) |
| | | 1.56 (peak) |

## C. Potential to Emit

1. Pre-Project Potential to Emit (PE1)

<u>N-3299-4-0, '-5-0, '-6-0</u>
The proposed emission units are new to the Stationary Source. Therefore, no pre-project emissions exist at this point for these units.

2. Post Project Potential to Emit (PE2)

<u>N-3299-4-0, '-5-0, '-6-0</u>
TID is expected to complete the commissioning activities for each CTG within 96 hours of its initial startup. The proposed maximum emissions during the commissioning period are summarized in the following table for each pollutant. The hourly emission limits are

taken from Table 5.1B-7a of the application package. Hourly CO limit, in the following table, is revised in direct response to address one of the comments from the applicant.

| Pollutant | PE (lb/hr) | PE (lb/day) | Commissioning Activity |
|---|---|---|---|
| $NO_X$ | 40.40 | 969.6 | No load test |
| CO | 40.00 | 704.6 | No load test |
| VOC | 8.41 | 201.8 | No load test |
| $PM_{10}$ | 2.50 | 60.0 | No load test, Min. load no SCR or no Oxidation catalyst, full SCR/oxidation catalyst |
| $SO_X$ | 1.56 | 37.4 | FSNL, Min. load no SCR or no Oxidation catalyst, full SCR/oxidation catalyst |

Potential NOx, CO and VOC emissions from each CTG are proposed to be determined using the operating schedule given in the following table for each quarter (Q).

| Operating Schedule (hours) for $NO_x$, CO, VOC Emissions Calculations | | | | | |
|---|---|---|---|---|---|
| Category | Daily | Q1 | Q2 | Q3 | Q4 |
| Gas Turbine, startups/shutdowns | 2 | 90 | 91 | 92 | 92 |
| Gas Turbine, base | -- | 1,980 | 2,002 | 2,024 | 2,024 |
| Gas Turbine, peak | 22 | -- | -- | -- | -- |

Potential emissions are calculated by multiplying the operating schedule with the proposed hourly emission limit for each category.

| Potential $NO_X$ Emissions | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 25.00 | 50.0 | 2,250 | 2,275 | 2,300 | 2,300 | 9,125 |
| Turbine, base | 4.74 | -- | 9,385 | 9,489 | 9,594 | 9,594 | 38,062 |
| Turbine, peak | 5.02 | 110.4 | -- | -- | -- | -- | -- |
| Total: | | **160.4** | 11,635 | 11,764 | 11,894 | 11,894 | **47,187** |
| Daily (without startup/shutdown)[1]: | | **120.5** | -- | -- | -- | -- | -- |
| **Potential CO Emissions** | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 40.00 | 80.0 | 3,600 | 3,640 | 3,680 | 3,680 | 14,600 |
| Turbine, base | 4.61 | -- | 9,128 | 9,229 | 9,331 | 9,331 | 37,019 |
| Turbine, peak | 4.89 | 107.6 | -- | -- | -- | -- | -- |
| Total: | | **187.6** | 12,728 | 12,869 | 13,011 | 13,011 | **51,619** |
| Daily (without startup/shutdown)[1]: | | **117.4** | -- | -- | -- | -- | -- |
| **Potential VOC Emissions** | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.00 | 4.0 | 180 | 182 | 184 | 184 | 730 |
| Turbine, base | 1.32 | -- | 2,614 | 2,643 | 2,672 | 2,672 | 10,601 |
| Turbine, peak | 1.40 | 30.8 | | | | | |
| Total: | | **34.8** | 2,794 | 2,825 | 2,856 | 2,856 | **11,331** |
| Daily (without startup/shutdown)[1]: | | **33.6** | -- | -- | -- | -- | -- |

[1] PE (lb/day) = $PE_{peak}$ lb/hr × 24 hr/day

Potential $NH_3$, $PM_{10}$ and $SO_x$ emissions from each gas turbine are proposed to be calculated by using the operating schedule given in the following table.

| **Operating Schedule (hours) for $SO_x$, $PM_{10}$, $NH_3$ Emissions Calculations** | | | | | |
|---|---|---|---|---|---|
| Category | Daily | Q1 | Q2 | Q3 | Q4 |
| Turbine, startups/shutdowns | 2 | 90 | 91 | 92 | 92 |
| Turbine, base | -- | 2,070 | 2,093 | 2,116 | 2,116 |
| Turbine, peak | 22 | -- | -- | -- | -- |

Potential emissions are calculated by multiplying the operating schedule with the proposed hourly emission limit for each category.

| **Potential $NH_3$ Emissions** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 7.44 | 14.9 | 670 | 677 | 684 | 684 | 2,715 |
| Turbine, base | 7.01 | -- | 14,511 | 14,672 | 14,833 | 14,833 | 58,849 |
| Turbine, peak | 7.44 | 163.7 | -- | -- | -- | -- | -- |
| Total: | | **178.6** | 15,181 | 15,349 | 15,517 | 15,517 | **61,564** |
| Daily (without startup/shutdown)[1]: | | **178.6** | -- | -- | -- | -- | -- |
| **Potential $PM_{10}$ Emissions** | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.50 | 5.0 | 225 | 228 | 230 | 230 | 913 |
| Turbine, base | 2.50 | -- | 5,175 | 5,233 | 5,290 | 5,290 | 20,988 |
| Turbine, peak | 2.50 | 55.0 | -- | -- | -- | -- | -- |
| Total: | | **60.0** | 5,400 | 5,461 | 5,520 | 5,520 | **21,901** |
| Daily (without startup/shutdown)[1]: | | **60.0** | -- | -- | -- | -- | -- |
| **Potential $SO_x$ Emissions** | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 1.56 | 3.1 | 140 | 142 | 144 | 144 | 570 |
| Turbine, base | 1.47 | -- | 3,043 | 3,077 | 3,111 | 3,111 | 12,342 |
| Turbine, peak | 1.56 | 34.3 | -- | -- | -- | -- | -- |
| Total: | | **37.4** | 3,183 | 3,219 | 3,255 | 3,255 | **12,912** |
| Daily (without startup/shutdown)[1]: | | **37.4** | -- | -- | -- | -- | -- |

[1] PE (lb/day) = $PE_{peak}$ lb/hr × 24 hr/day

3. Adjusted increase in Permitted Emissions (AIPE) Calculations

AIPE is used to determine if BACT is required for emission units that are being modified. The proposed units are new emission units. Therefore, AIPE calculations are not necessary.

## D. Facility Emissions

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

Pursuant to Section 4.9 of District Rule 2201, SSPE1 is the Potential to Emit from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERCs) which have been banked since September 19, 1991 for Actual Emissions Reductions (AERs) that have occurred at the source, and which have not been used on-site. Please refer to Attachment H of this document for potential emissions calculations for permit units N-3299-1 and N-3299-3.

| SSPE1 (lb/yr) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit #** | **Type of Unit** | **$NO_x$** | **CO** | **VOC** | **$PM_{10}$** | **$SO_x$** |
| N-3299-1-2 | 240 bhp, diesel- fueled emergency fire pump IC engine | 97 | 23 | 7 | 4 | 0 |
| N-3299-3-2 | GE's LM-6000, 48 MW | 52,049 | 136,413 | 10,454 | 17,520 | 11,459 |
| ERC | | 0 | 0 | 0 | 0 | 0 |
| Total | | 52,146 | 136,436 | 10,461 | 17,524 | 11,459 |
| Major Source Thresholds | | 50,000 | 200,000 | 50,000 | 140,000 | 140,000 |
| Major Source? | | **Yes** | No | No | No | No |

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

Pursuant to Section 4.10 of District Rule 2201, the Post-Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

| SSPE2 (lb/yr) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit #** | **Type of Unit** | **$NO_x$** | **CO** | **VOC** | **$PM_{10}$** | **SOx** |
| N-3299-1-2 | 240 bhp, diesel- fueled emergency fire pump IC engine | 97 | 23 | 7 | 4 | 0 |
| N-3299-3-2 | GE's LM-6000, 48 MW | 52,049 | 136,413 | 10,454 | 17,520 | 11,459 |
| N-3299-4-0 | GE's LM-6000 PG SPRINT, 54.2 MW | 47,187 | 51,619 | 11,331 | 21,901 | 12,912 |
| N-3299-5-0 | GE's LM-6000 PG SPRINT, 54.2 MW | 47,187 | 51,619 | 11,331 | 21,901 | 12,912 |
| N-3299-6-0 | GE's LM-6000 PG SPRINT, 54.2 MW | 47,187 | 51,619 | 11,331 | 21,901 | 12,912 |
| ERC | | 0 | 0 | 0 | 0 | 0 |
| Total | | 193,707 | 291,293 | 44,454 | 83,227 | 50,195 |
| Major Source Thresholds | | 50,000 | 200,000 | 50,000 | 140,000 | 140,000 |
| Major Source? | | **Yes** | **Yes** | No | No | No |

3. Stationary Source Increase in Permitted Emissions (SSIPE)

It is a District Practice to define the SSIPE as the difference of SSPE2 and SSPE1. Negative SSIPE is equated to zero. SSIPE is summarized in the following table:

| Pollutant | SSPE2 (lb/year) | SSPE1 (lb/year) | SSIPE (lb/year) |
|---|---|---|---|
| $NO_x$ | 193,707 | 52,146 | 141,561 |
| CO | 291,293 | 136,436 | 154,857 |
| VOC | 44,454 | 10,461 | 33,993 |
| $PM_{10}$ | 83,227 | 17,524 | 65,703 |
| $SO_x$ | 50,195 | 11,459 | 38,736 |

4. District Major Modification

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

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

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

Per section VII.D.2 of this document, this facility is a Major Source for NOx and CO emissions. Since the San Joaquin Valley is in attainment for CO, NEI calculations for CO are not necessary.

To determine if a project triggers a Major Modification, Net Emissions Increase (NEI) is calculated for NOx, and is compared with the Major Modification threshold limit for this pollutant, which 50,000 lb/yr.

NEI can be calculated as the sum of the difference of post-project potential emissions (PE2) and historical emissions (HE) for the emissions unit involved in this project. HE for the emission units involved in this project is zero. Thus,

<u>$NO_x$</u>

| Permit | PE2 (lb/yr) | HE (lb/yr) | NEI = PE2- HE (lb/yr) | Major Modification Thresholds (lb/yr) | Major Modification? |
|---|---|---|---|---|---|
| N-3299-4-0 | 47,187 | 0 | 47,187 | 50,000 | Yes |
| N-3299-5-0 | 47,187 | 0 | 47,187 | | |
| N-3299-6-0 | 47,187 | 0 | 47,187 | | |
| | | Total: | 141,561 | | |

5. Federal Major Modification

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

A. If a Rule-compliance project qualifies for District Rule 2201's Best Available Control Technology (BACT) and offset exemptions (District Rule 2201, §4.2.3.5); and

B. If an Alternate Siting analysis must be performed (District Rule 2201, §4.15.1);

C. If the applicant must provide certification that all California stationary sources owned, operated, or controlled by the applicant that are subject to emission limits are in compliance with those limits or are on a schedule for compliance with all applicable emission limits and standards; and

D. If a public notification is triggered. (District Rule 2201, §5.4.1) Although the language in §5.4.1 states "Major Modifications", the District is taking a conservative approach by assuming this applies to both District Rule 2201 Major Modifications and Federal Major Modifications.

Per section VII.D.4 of this document, this project is a Major Modification for NOx only. To determine if it would be a Federal Major Modification, Net Emissions Increase (NEI) is calculated for NOx, and is compared with the Significance Threshold level of 50,000 lb/year for NOx.

NEI can be calculated as the sum of the difference of project actual emissions (PAE) and Baseline Actual Emissions (BAE). BAE for the emission units involved in this project is zero. Thus,

<u>NOx</u>

<table>
<tr><th>Permit</th><th>PAE (lb/yr)</th><th>BAE (lb/yr)</th><th>NEI = PAE2- BAE (lb/yr)</th><th>Significance Thresholds (lb/yr)</th><th>Federal Major Modification?</th></tr>
<tr><td>N-3299-4-0</td><td>47,187</td><td>0</td><td>47,187</td><td rowspan="4">50,000</td><td rowspan="4">Yes</td></tr>
<tr><td>N-3299-5-0</td><td>47,187</td><td>0</td><td>47,187</td></tr>
<tr><td>N-3299-6-0</td><td>47,187</td><td>0</td><td>47,187</td></tr>
<tr><td colspan="3">Total:</td><td>141,561</td></tr>
</table>

## VIII. COMPLIANCE

### Rule 1080 Stack Monitoring

This rule grants the APCO the authority to request the installation, use, maintenance, and inspection of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

TID has proposed to monitor NOx, CO and $O_2$ concentrations from each gas turbine system using CEMs to meet the requirements of applicable District rules and Federal regulations. Therefore, the following conditions will be placed on each permit to ensure compliance with the requirements of this rule.

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NOx and $O_2$ CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- The NOx and $O_2$ CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h) and in accordance with 40 CFR 60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

- Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.7(b)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

**Rule 1081 Source Sampling**

This Rule requires adequate and safe sampling facilities such as sampling ports, sampling platforms, access to the sampling platforms for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The following conditions will be placed on each permit to ensure compliance with the requirements of this rule.

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- 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]

- Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]

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

Compliance is expected with this Rule.

**Rule 1100 Equipment Breakdown**

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified. The following conditions will be placed on each permit to ensure compliance with the requirements of this rule.

- The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Compliance is expected with this Rule.

**Rule 2010 Permits Required**

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, TID is complying with the requirements of this Rule.

**Rule 2201 New and Modified Stationary Source Review Rule**

**1. Best Available Control Technology (BACT)**

BACT requirements shall be triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless exempted pursuant to Section 4.2, BACT shall be required for the following actions:

- Any new emissions unit or relocation from one Stationary Source to another of an existing emissions unit with a Potential to Emit (PE2) exceeding 2.0 pounds in any one day;

- Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds in any one day;

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

<u>N-3299-4-0, '-5-0, '-6-0</u>

Per section VII.C.2 of this document, PE2 is greater than 2.0 lb/day for NOx, SOx, $PM_{10}$, CO and VOC emissions. CO emissions from the entire facility are greater than 200,000 lb/year. Therefore, BACT is triggered for each pollutant.

BACT Guideline 3.4.7 is referenced to determine the BACT for each pollutant. The detailed "Top-Down BACT Analysis" for each pollutant is presented in Attachment E of this document. Summary of BACT requirements is explained briefly in the following section.

BACT applies during all modes of operation, including startup and shutdown periods. The BACT limits discussed below applies during the steady-state operation, when the turbines reach stable operations and the emission control systems are fully operational.

BACT during Steady-State Emissions

*NOx*
The above referenced guideline lists 5.0 ppmvd @ 15% $O_2$ (3-hour average) as achieved-in-practice, and 3.0 ppmvd @ 15% $O_2$ (3-hour average) and 2.5 ppmvd @ 15% $O_2$ (1-hour average) as technologically feasible options.

TID has proposed to meet 2.5 ppmvd @ 15% $O_2$ on 1-hour rolling average. Therefore, this unit satisfies the District BACT requirements for NOx emissions.

*CO*
The above referenced guideline lists 6.0 ppmvd @ 15% $O_2$ (3-hour average) as achieved-in-practice. There is no technologically feasible option listed in the guideline for CO.

TID has proposed to meet 4.0 ppmvd @ 15% $O_2$ on 3-hour rolling average. Therefore, this unit satisfies the District BACT requirements for CO emissions.

*VOC*
The above referenced guideline lists 2.0 ppmvd @ 15% $O_2$ (3-hour average) as achieved-in-practice, and 1.3 ppmvd @ 15% $O_2$ (3-hour average) and 0.6 ppmvd @ 15% $O_2$ (3-hour average) as technologically feasible options.

It is not cost-effective to customize oxidation catalyst to meet either 1.3 ppmvd @ 15% $O_2$ (3-hour average) or 0.6 ppmvd @ 15% $O_2$ (3-hour average). Therefore, these options are removed from consideration.

TID has proposed to meet 2.0 ppmvd @ 15% $O_2$ on 3-hour rolling average. Therefore, this unit satisfies the District BACT requirements for VOC emissions.

*$PM_{10}$*
The above referenced guideline lists the use of air inlet filter cooler, lube oil vent coalescer using either PUC regulated natural gas, LPG or non-PUC regulated gas with less than 0.75 gr-S/100 dscf to minimize the $PM_{10}$ emissions.

Each CTG will be exclusively fired on PUC-regulated natural gas. Furthermore, each CTG will have air inlet filter cooler and lube oil vent coalescer. Therefore, each CTG satisfies the District BACT requirements for $PM_{10}$ emissions.

*SOx*
The above referenced guideline lists PUC-regulated natural gas, LPG, or non-PUC regulated gas with no more than 0.75 gr-S/100 dscf.

TID has proposed to use PUC-regulated natural gas in each CTG. Therefore, each unit satisfies the District BACT requirements for SOx emissions.

BACT during Startup and/or Shutdown

Startup and shutdown activities are normal part of operation of a simple-cycle power plant. During startup of a gas turbine, firing rate (or load) is gradually increased over successive time intervals to protect the gas turbine and the emission control system from thermal stress. When a gas turbine operates at low loads, the operation is inefficient and emissions are relatively high compared to a gas turbine operating under high loads and steady-state condition. The post combustion controls (SCR system and oxidation catalyst) that are used to achieve additional emission reductions must be maintained at a specific temperature to effectively control NOx, CO and VOC. When an SCR catalyst surface temperature is low, ammonia will not react completely with NOx, and results in excess NOx emissions or excess ammonia slip. Similarly, the oxidation catalyst is not effective in controlling CO emissions when exhaust temperature is outside the optimal operating range. Given that simple-cycle power plant configurations have to rely on gas turbine's exhaust to heat-up the SCR and oxidation catalyst modules, the startup emissions seems to be unavoidable. There is no known practically efficient demonstrated method to elevate temperature of the catalyst modules for optimum functioning or earlier ammonia injection in the SCR system to reduce $NO_X$ emissions from simple-cycle power plants.

TID's consultant states that the proposed NOx, CO and VOC emissions (lb/hr) during startup (or shutdown) represent achievable emissions limits based on experience with other similar turbine projects. TID is proposing to be in compliance with the steady-state emission limits within one-hour of the startup of the CTG. Therefore, the proposed emission limits along with the startup time to achieve these limits can be considered as BACT for startup (or shutdown).

TID's proposal to achieve the steady-state emissions within one-hour of the startup of the gas turbine appears to be more stringent than the startup time allowed for similar permitted gas turbines. The following conditions will be placed on each permit:

- Startup of this gas turbine system shall not exceed one-hour per event. [District Rules 2201 and 4703]

- Shutdown of this gas turbine system shall not exceed one-hour per event. [District Rule 2201 and 4703]

- Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 160.4 lb/day; CO – 187.6 lb/day; VOC – 34.8 lb/day; PM10 – 60.0 lb/day; SOx (as SO2) – 37.4 lb/day, or $NH_3$ – 178.6 lb/day. [District Rule 2201]

- During start-up or shutdown period, the emissions shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 25.00 lb/hr; CO – 40.00 lb/hr; VOC (as methane) – 2.00 lb/hr; $PM_{10}$ – 2.50 lb/hr; $SO_X$ (as $SO_2$) – 1.56 lb/hr; or $NH_3$ – 7.44 lb/hr. [District Rules 2201 and 4703]

Please note that the combined startups and shutdowns are not limited to 2.0 hours per day. The reason being is that this is a peaker plant and they may have multiple startups and shutdowns in a given day, and there is a chance that they may exhaust 2.0 hours per day earlier while still maintaining compliance with the daily emissions limit listed above. Therefore, combined startups and shutdowns are not limited to 2.0 hours per day.

TID is expected to submit the minimum temperature at the SCR catalyst face once they select SCR vendor for this project. Having minimum temperature limit in the permit will ensure that ammonia injection will continually occurs at the established temperature regardless of startup mode (hot, warm or cold). The following permit conditions will be placed on the permit:

- During all types of operation (with an exception of ammonia injection tuning prior to the initial source test during the commissioning period), including startup and shutdown periods, ammonia injection into the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- The District shall administratively add the minimum temperature limitation established pursuant to the above condition in the final Permit to Operate. The District may administratively modify the temperature as necessary following any replacement of the SCR catalyst material. [District Rule 2201]

$SO_2$ and $PM_{10}$ emissions are result of the characteristics of the fuel being burned and do not rely on any emissions control system. Therefore, the BACT determinations (discussed above) for $SO_2$ and $PM_{10}$ emissions are considered BACT for startup (and/or shutdown).

## 2. Offsets

Offsets are examined on a pollutant-by-pollutant basis, and are triggered for any pollutant with a SSPE2 equal to or greater than the threshold listed in following table.

| Pollutant | SSPE1 (lb/yr) | SSPE2 (lb/yr) | Offset Thresholds (lb/yr) | Offset Triggered? |
|---|---|---|---|---|
| $NO_x$ | 52,146 | 193,707 | 20,000 | Yes |
| CO | 136,436 | 291,293 | 200,000 | Yes |
| VOC | 10,461 | 44,454 | 20,000 | Yes |
| $PM_{10}$ | 17,524 | 83,227 | 29,200 | Yes |
| $SO_x$ | 11,459 | 50,195 | 54,750 | No |

Offset Calculations

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

EOQ = Σ(PE2 – BE) + ICCE, where

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

Section 4.7.2 states that for pollutants with SSPE1 less than or equal to the offset threshold levels, emission offsets shall be provided for all increases in Stationary Source emissions above the offset trigger levels, calculated as the difference of SSPE2 (lb/yr) and the offset trigger level (lb/yr), plus all increases in Cargo Carrier emissions (lb/yr). Thus,

EOQ = (SSPE2 – Offset Threshold Level) + ICCE, where

EOQ = Emissions Offset Quantity (lb/yr)
ICCE = Increase in Cargo Carrier emissions (lb/yr)

*NOx*
SSPE1 for NOx is greater than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. BE is equal to zero for each emission unit. Thus,

EOQ = ΣPE2

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| N-3299-4-0 | 11,635 | 11,764 | 11,894 | 11,894 |
| N-3299-5-0 | 11,635 | 11,764 | 11,894 | 11,894 |
| N-3299-6-0 | 11,635 | 11,764 | 11,894 | 11,894 |
| EOQ (lb) | 34,905 | 35,292 | 35,682 | 35,682 |

TID has proposed to use ERC certificate S-3113-2 to offset NOx emissions increase from this project.

| ERC # | Original Reduction Site | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|---|
| S-3113-2 | Tupman, Ca | 55,800 | 55,800 | 55,800 | 55,800 |
| | Total ERCs Available: | 55,800 | 55,800 | 55,800 | 55,800 |

Using the offset ratio of 1.5, this facility must offset the amount listed in following table for each quarter.

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| Offset (EOQ x 1.5) (lb) | 52,358 | 52,938 | 53,523 | 53,523 |
| ERCs Available (lb) | 55,800 | 55,800 | 55,800 | 55,800 |

For each quarter, the amount of offsets required is less than the total amount of credits available in the proposed use of ERC S-3113-2. Therefore, it is concluded that the proposed certificate is sufficient to offset the NOx emissions increase from this project. The following conditions will be listed on each permit:

- Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 34,905 lb, 2nd quarter: 35,292 lb, 3rd quarter: 35,682 lb, and 4th quarter: 35,682 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- NOx ERC S-3113-2 (or a certificate split from this certificate) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

*CO*
Section 4.6.1 of Rule 2201 states that emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

San Joaquin Valley is in attainment for CO emissions. Based on the results of Ambient Air Quality Analysis (AAQA), Ambient Air Quality Standard (AAQS) for CO is not violated in the affected area. Therefore, offsets are not required for CO emissions increase. Please refer to Attachment F of this document for AAQA.

*VOC*
SSPE1 for VOC emissions is less than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. Thus,

$$
\begin{aligned}
EOQ_{VOC} &= \text{SSPE2 lb/yr} - \text{20,000 lb/yr}\\
&= \text{44,454 lb/yr} - \text{20,000 lb/yr}\\
&= \text{24,454 lb/yr}
\end{aligned}
$$

EOQ on quarterly basis is determined by multiplying the emission percent contribution [i.e. Total (lb/quarter)/Total (lb/year)] with EOQvoc of 24,454 lb/yr. For example,

$EOQ_{Q1}$ = (0.25)(24,454 lb/yr)
= 6,114 lb

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| N-3299-4-0 | 2,794 | 2,825 | 2,856 | 2,856 |
| N-3299-5-0 | 2,794 | 2,825 | 2,856 | 2,856 |
| N-3299-6-0 | 2,794 | 2,825 | 2,856 | 2,856 |
| PE2 (Total): | 8,382 | 8,475 | 8,568 | 8,568 |
| % | 25% | 25% | 25% | 25% |
| EOQ (lb) | 6,113 | 6,113 | 6,114 | 6,114 |

TID has proposed to use ERC certificate C-1008-1 to offset VOC emissions increase from this project.

| ERC # | Original Reduction Site | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|---|
| C-1008-1 | Fresno, Ca | 10,250 | 10,250 | 10,250 | 10,250 |
| | ERCs Available: | 10,250 | 10,250 | 10,250 | 10,250 |

Using offset ratio of 1.5, this facility must offset the amount listed in following table for each quarter.

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| Offset (EOQ x 1.5) (lb) | 9,170 | 9,170 | 9,171 | 9,171 |
| ERCs Available (lb) | 10,250 | 10,250 | 10,250 | 10,250 |

For each quarter, the amount of offsets required is less than the total amount of credits available in the proposed use of ERC C-1008-1. Therefore, it is concluded that the proposed certificate is sufficient to offset the VOC emissions increase from this project. The following conditions will be listed on each permit:

- Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 6,113 lb, 2nd quarter: 6,113 lb, 3rd quarter: 6,114 lb, and 4th quarter: 6,114 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- VOC ERC C-1008-1 (or a certificate split from this certificate) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

_$PM_{10}$_
SSPE1 for $PM_{10}$ emissions is less than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. Thus,

$EOQ_{PM10}$ = SSPE2 lb/yr – 29,200 lb/yr
= 83,227 lb/yr – 29,200 lb/yr
= 54,027 lb/yr

EOQ on quarterly basis is determined by multiplying the emission percent contribution [i.e. Total (lb/quarter)/Total (lb/year)] with $EOQ_{PM10}$ of 54,027 lb/yr. For example,

$EOQ_{Q1}$ = (0.25)(54,027 lb/yr) = 13,506 lb

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| N-3299-4-0 | 5,400 | 5,461 | 5,520 | 5,520 |
| N-3299-5-0 | 5,400 | 5,461 | 5,520 | 5,520 |
| N-3299-6-0 | 5,400 | 5,461 | 5,520 | 5,520 |
| PE2 (Total): | 16,200 | 16,383 | 16,560 | 16,560 |
| % | 25% | 25% | 25% | 25% |
| EOQ (lb) | 13,506 | 13,507 | 13,507 | 13,507 |

TID has proposed to use SOx ERC certificate S-3129-5 to offset $PM_{10}$ emissions increase from this project.

This certificate does not have any credits in the third quarter. Credits from Q4, an amount of 20,261 lbs, can be moved in Q3 to cover this shortfall. This action is consistent with Section 4.13.7 of Rule 2201, which states that AER for PM[1] that occurred from October through March, inclusive, may be used to offset increases in PM during any period of the year.

| ERC # | Original Reduction Site | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|---|
| S-3129-5 | Bakersfield, Ca | 55,614 | 40,150 | 0 | 84,936 |
| | ERCs Available: | 55,614 | 40,150 | 20,261 | 64,675 |

Using the offset ratio of 1.5, this facility must offset the amount listed in following table for each quarter.

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| Offset (EOQ x 1.5) (lb) | 20,259 | 20,261 | 20,261 | 20,261 |
| ERCs Available (lb) | 55,614 | 40,150 | 20,261 | 64,675 |

Based on the atmospheric modeling conducted by the District (Refer to Attachment G of this document), $SOx/PM_{10}$ inter-pollutant offset ratio is 1.0.

[1] SOx is a pre-cursor to the sulfate fraction of $PM_{10}$ per Table 3-5 of Rule 2201. Therefore, it is logical to move Q4 credits into Q3.

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| $PM_{10}$ Offset (lb) | 20,259 | 20,261 | 20,261 | 20,261 |
| SOx ERCs Available (lb) | 55,614 | 40,150 | 20,261 | 64,675 |

Based on the above table, TID has sufficient amount of SOx credits. The following conditions will be placed on each permit:

- Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of $PM_{10}$: 1st quarter: 13,506 lb, 2nd quarter: 13,507 lb, 3rd quarter: 13,507 lb, and 4th quarter: 13,507 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- SOx ERC S-3129-5 (or a certificate split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

- The District has authorized to use SOx reductions to offset emissions increase in PM10 at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201]

## 3. Public Notice

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

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

Public notification is required for this project, as this project exceeded thresholds of many items listed above.

## 4. Daily Emission Limits (DELs)

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

- Emission rates from the gas turbine system during the commissioning period shall not exceed any of the following limits: NOx (as NO2) – 40.40 lb/hr and 969.6 lb/day; VOC (as CH4) – 8.41 lb/hr and 201.8 lb/day; CO – 40.00 lb/hr and 704.6 lb/day; PM10 – 2.50 lb/hr and 60.0 lb/day; or SOx (as SO2) – 1.56 lb/hr and 37.4 lb/day. [District Rule 2201]

- Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) – 5.02 lb/hr and 2.5 ppmvd @ 15% O2; CO – 4.89 lb/hr and 4.0 ppmvd @ 15% O2; VOC (as methane) – 1.40 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 2.50 lb/hr; or SOx (as SO2) – 1.56 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

- During start-up or shutdown period, the emissions shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 25.00 lb/hr; CO – 40.00 lb/hr; VOC (as methane) – 2.00 lb/hr; $PM_{10}$ – 2.50 lb/hr; $SO_X$ (as $SO_2$) – 1.56 lb/hr; or $NH_3$ – 7.44 lb/hr. [District Rules 2201 and 4703]

- Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 160.4 lb/day; CO – 187.6 lb/day; VOC – 34.8 lb/day; PM10 – 60.0 lb/day; SOx (as SO2) – 37.4 lb/day, or $NH_3$ – 178.6 lb/day. [District Rule 2201]

- Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: $NO_X$ (as $NO_2$) – 120.5 lb/day; CO – 117.4 lb/day; VOC – 33.6 lb/day; $PM_{10}$ – 60.0 lb/day; $SO_X$ (as $SO_2$) – 37.4 lb/day, or $NH_3$ – 178.6 lb/day. [District Rule 2201]

- NH3 emissions shall not exceed 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period. [District Rule 2201]

The following emissions limits are placed on each permit to ensure compliance with quarterly emissions (or to validate the emission offsets).

- NOx (as NO2) emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 11,635 lb; 2nd quarter: 11,764 lb; 3rd quarter: 11,894 lb; 4th quarter: 11,894 lb. [District Rule 2201]

- CO emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 12,728 lb; 2nd quarter: 12,869 lb; 3rd quarter: 13,011 lb; 4th quarter: 13,011 lb. [District Rule 2201]

- VOC emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 2,794 lb; 2nd quarter: 2,825 lb; 3rd quarter: 2,856 lb; 4th quarter: 2,856 lb. [District Rule 2201]

- NH3 emissions from the SCR system associated with this gas turbine system shall not exceed any of the following: 1st quarter: 15,181 lb; 2nd quarter: 15,349 lb; 3rd quarter: 15,517 lb; 4th quarter: 15,517 lb. [District Rule 2201]

- PM10 emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 5,400 lb; 2nd quarter: 5,461 lb; 3rd quarter: 5,520 lb; 4th quarter: 5,520 lb. [District Rule 2201]

- SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 3,183 lb; 2nd quarter: 3,219 lb; 3rd quarter: 3,255 lb; 4th quarter: 3,255 lb. [District Rule 2201]

- Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

## 5. Compliance Assurance

Source Testing

TID is required to perform a source test to measure hourly NOx, CO and VOC mass emission rates during the startup period for each CTG. This test is required to be completed before the end of the commissioning period, and must be repeated at least once every seven years thereafter provided that the CEMS relative accuracy is demonstrated on annual basis. $PM_{10}$ emissions rate during the startup is expected to be same when gas turbine system operates in a steady-state mode, and therefore, it is not necessary to measure hourly $PM_{10}$ mass emission rate during the startup period. SOx emissions during the startup period can be determined using sulfur content in the natural gas.

TID is also required to measure $NO_x$, CO, VOC, $NH_3$ and $PM_{10}$ emissions during the steady state period for each CTG. This test is also required to be performed before the end of commissioning period and must be repeated at least once every twelve months. The source test requirements are consistent with District Rule 4703, District Policy APR-1705 (10/9/97) and permitted similar facilities.

TID has proposed to use PUC regulated natural gas, and they are required to keep records of gas purchase receipts and or tariff and the amount of sulfur content in gas to demonstrate compliance with 1.0 grain-S/100 dscf of natural gas. If the sulfur content information is not available from the gas supplier, then the permittee is required to test fuel sulfur content on weekly basis. Upon successful compliance demonstration on 8 week consecutive tests, the test frequency shall be reduced to every six months. If any six-month test shows non-compliance with the sulfur content requirement, weekly testing will resume until eight consecutive weeks show compliance. This source test methodology is consistent with recently permitted similar facilities.

Monitoring

The permittee has proposed to use a continuous emissions monitoring system (CEMS) to monitor NOx, CO and $O_2$ concentrations from each gas turbine system. NOx diluent monitor is required to be installed, certified and operated in a manner required in 40 CFR Part 75 (Acid Rain), and CO and $O_2$ monitors are required to installed, certified and operated in a manner required in 40 CFR Part 60 Subpart KKKK.

Sulfur content in PUC regulated natural gas is expected to stay at or below 1.0 grain/100 scf. For this reason, it is expected that the gas turbine system will always be in compliance with SOx emissions limit. No separate $SO_2$ monitor is proposed by the TID or is required by the applicable District Rules or Federal regulations.

VOC and $PM_{10}$ emissions will be monitored during each source test. Test results along with the heat input rate on hourly basis will assure on-going compliance with hourly, daily and quarterly emissions limits.

Recordkeeping

The permittee is required to keep records of hourly emissions, daily emissions, quarterly emissions, source tests and monitoring parameters. These records are required to be kept for at least five years.

Reporting

The applicant is required to submit source test results within 60 after each source test.

## 6. Ambient Air Quality Analysis (AAQA)

Section 4.14.1 requires an AAQA to be performed for projects that trigger public notice. The following table shows the summary of AAQA:

**Criteria Pollutant Modeling Results***

| Units N-3299-4-0, '-5-0 and '-6-0 | 1 Hour | 3 Hours | 8 Hours | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_X$ | Pass | X | X | X | Pass |
| $SO_X$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[1] | Pass[1] |

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

The criteria modeling runs indicate that the emissions from the proposed emission units will not cause or significantly contribute to a violation of the State or National Ambient Air Quality Standards. Please refer to Attachment F of this document for AAQA.

## 7. Alternative Siting and Compliance Certification

Section 4.15.1 states that sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the Federal Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. Seq. of the Public Resource Code.

TID has included Alternative Siting analysis in the Application for Certification (AFC) to the CEC. CEC is the lead agency on CEQA, and their approval of the proposed Alternative Siting analysis will ensure compliance with this section. A copy of the proposed analysis will be included in Attachment I of this document.

Section 4.15.2 requires the owner of a new Major Source or a Federal Major Modification to demonstrate to the satisfaction of the District that all other major Stationary Sources owned by such person in California are in compliance with all applicable emission limitations and standards.

TID has supplied a compliance certification that all major Stationary Sources owned or operated (or by any entity controlling, controlled by, or under common control) in California are in compliance with all applicable emission limitations and standards. In other words, none of their facility is under "Variance" from the applicable emission standards. This certification is included in Attachment I of this document.

Compliance is expected with this Rule.

## Rule 2520 Federally Mandated Operating Permits

TID currently possesses a Title V permit. The proposed project is classified as "Significant Modification", as the project results in a Federal major modification, and is subject to NSPS standards listed in 40 CFR Part 60 subpart KKKK. The applicant has proposed to receive the ATCs with Certificates of Conformity in accordance with the requirements of 40 CFR 70.6(c), 70.7 and 70.8. Therefore, 45-day EPA notice will be conducted prior to the issuance of the ATCs. The following federally enforceable conditions will be placed on the ATCs:

- This Authority to Construct serves as a written Certificate of Conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2520]

- Prior to operating with the modifications authorized by this Authority to Construct, the facility shall submit an application for an administrative amendment to its Title V permit, in accordance with District Rule 2520, Section 11.4.2. [District Rule 2520]

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

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

- The source's suggested draft permit (Attachment A of this document) and

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

Section 5.3.4 of this rule requires the permittee shall file an application for administrative permit amendments prior to implementing the requested change except when allowed by the operational flexibility provisions of section 6.4 of this rule. TID is expected to notify the District by filing TV Form -008 upon implementing the ATCs. After successful compliance demonstration, the District Compliance Division is expected to submit a change order to implement these ATCs into Permits to Operate.

Compliance is expected with this Rule.

**Rule 2540 Acid Rain Program**

This rule is applicable to all stationary sources that are subject to Part 72, Title 40, Code of Federal Regulations (CFR). 40 CFR 72.30(b)(2)(iii) require submission of an acid rain permit application at least 24 months before the date the unit expects to generate electricity. This facility is anticipated to begin full-scale commercial operation by the fourth quarter of 2011. Per project consultant, TID is expected to submit an "Acid Rain Permit Application" to the District in the near future. The following permit conditions will be included in each permit:

- The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72]

- The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75]

- The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75]

- The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73]

- Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77]

- Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72]

- An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73]

- An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72]

- An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72]

- The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77]

- The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77]

- The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72]

- The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75]

- The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75]

Compliance is expected with this Rule.

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

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

TID stated that this site is not a Major Source (i.e. PE >10 tons/yr for single HAP, PE > 25 tons/yr for combined HAPs). Therefore, this facility is not subject to the requirements of this Rule. Discussion and calculations related to this determination are given in the following section.

Non-criteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[2]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

TID has identified non-criteria pollutant emission factors for the analysis of hazardous air emissions from the gas turbine. Except for hexane, polycyclic aromatic hydrocarbons (PAHs), and propylene oxide, the emission factors are obtained from AP-42 Table 3.1-3 (4/00). California Air Resources Board's California Air Toxics Emission Factors (CATEF) database for gas turbines (http://www.arb.ca.gov/app/emsinv/catef_form.html) was used to determine emissions for hexane, PAHs and propylene oxide. Mean values listed in the CATEF database was used in the analysis.

[2] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

N-3299-4-0, '-5-0, '-6-0

**GE LM6000 PG SPRINT**

| Hazardous Air Pollutant | Emission Factor (lb/MMBtu)(1) | Maximum Hourly Emissions (lb/hr) (2) from each CTG | Maximum Annual Emissions (lb/yr) (3) from each CTGs | Maximum Annual Emissions (tpy) from three CTGs |
|---|---|---|---|---|
| Acetaldehyde | 4.00E-05 | 2.09E-02 | 183 | 0.3 |
| Acrolein | 6.40E-06 | 3.35E-03 | 29 | 0.0 |
| Benzene | 1.20E-05 | 6.28E-03 | 55 | 0.1 |
| 1,3-Butadiene | 4.30E-07 | 2.25E-04 | 2 | 0.0 |
| Ethyl benzene | 3.20E-05 | 1.67E-02 | 147 | 0.2 |
| Formaldehyde | 7.10E-04 | 3.71E-01 | 3,253 | 4.9 |
| Hexane | 2.58E-04 | 1.35E-01 | 1,182 | 1.8 |
| Naphthalene | 1.30E-06 | 6.80E-04 | 6 | 0.0 |
| PAHs(4) (excluding Naphthalene) | 3.14E-07 | 1.64E-04 | 1 | 0.0 |
| Propylene Oxide | 4.76E-05 | 2.49E-02 | 218 | 0.3 |
| Toluene | 1.30E-04 | 6.80E-02 | 596 | 0.9 |
| Xylene | 6.40E-05 | 3.35E-02 | 293 | 0.4 |
| Total | | | | **8.9** |

(1) From AP-42 and CATEF databases.
(2) Based on heat input rate of 523 MMBtu/hr.
(3) Based on heat input rate of 4,581,480 MMBtu/year-turbine.
(4) Mean values of emission factors for Benzo(a)anthracene, Benzo(a)pyrene, Benzo(a)pyrene, Benzo(b)fluoranthrene, Benzo(k)fluoranthrene, Chrysene, Dibenz(a,h)anthracene, and ineno(1,2,3-cd)pyrene are obtained from CATEF database. These values are then adjusted by calculating the percentage of individual components in a combined total emission factor. This percentage is then multiplied with the difference of PAH and napthalene emission factor (9E-07 lb/MMBtu) and the individual weighted cancer risk relative to B(a)P. The obtained values are summed, which equates to 3.14E-07 lb/MMBtu.

HAP emissions from the existing units are as follows:

N-3299-1-2

**240 bhp Diesel-Fueled Emergency Engine**

| Hazardous Air Pollutant | Emission Factor (lb/MMBtu)(1) | Maximum Hourly Emissions (lb/hr) (2) | Maximum Annual Emissions (lb/yr) (3) | Maximum Annual Emissions (tpy) |
|---|---|---|---|---|
| Acetaldehyde | 7.67E-04 | 1.23E-03 | 0 | 0.0 |
| Acrolein | 9.25E-05 | 1.48E-04 | 0 | 0.0 |
| Benzene | 9.33E-04 | 1.49E-03 | 0 | 0.0 |
| 1,3-Butadiene | 3.91E-05 | 6.26E-05 | 0 | 0.0 |

**240 bhp Diesel-Fueled Emergency Engine (Continue…)**

| Hazardous Air Pollutant | Emission Factor (lb/MMBtu)(1) | Maximum Hourly Emissions (lb/hr) (2) | Maximum Annual Emissions (lb/yr) (3) | Maximum Annual Emissions (tpy) |
|---|---|---|---|---|
| Ethyl benzene | -- | -- | -- | -- |
| Formaldehyde | 1.18E-03 | 1.89E-03 | 0 | 0.0 |
| Hexane | n/a | -- | -- | -- |
| Naphthalene | 8.48E-05 | 1.36E-04 | 0 | 0.0 |
| PAHs | 8.32E-05 | 1.33E-04 | 0 | 0.0 |
| Propylene Oxide | n/a | -- | -- | 0.0 |
| Toluene | 4.09E-04 | 6.54E-04 | 0 | 0.0 |
| Xylene | 2.85E-04 | 4.56E-04 | 0 | 0.0 |
| **Total** | | | | **0.0** |

(1) AP-42 Table 3.3.-2 (10/96)
(2) Based on an hourly heat input rate of 1.6 MMBtu/hr (11.9 gal/hr x 0.137 MMBtu/gal).
(3) Per ATCM, this engine is allowed to be operated for 30 hr/yr for non-emergency purposes. Therefore, annual heat input rate would be 48 MMBtu/yr.

N-3299-3-2

**GE's LM6000 with Steam Injection**

| Hazardous Air Pollutant | Emission Factor (lb/MMBtu)(1) | Maximum Hourly Emissions (lb/hr) (2) | Maximum Annual Emissions (lb/yr) (3) | Maximum Annual Emissions (tpy) |
|---|---|---|---|---|
| Acetaldehyde | 4.00E-05 | 1.84E-02 | 161 | 0.1 |
| Acrolein | 6.40E-06 | 2.94E-03 | 26 | 0.0 |
| Benzene | 1.20E-05 | 5.51E-03 | 48 | 0.0 |
| 1,3-Butadiene | 4.30E-07 | 1.97E-04 | 2 | 0.0 |
| Ethyl benzene | 3.20E-05 | 1.47E-02 | 129 | 0.1 |
| Formaldehyde | 7.10E-04 | 3.26E-01 | 2,855 | 1.4 |
| Hexane | 2.58E-04 | 1.18E-01 | 1,037 | 0.5 |
| Naphthalene | 1.30E-06 | 5.97E-04 | 5 | 0.0 |
| PAHs | 1.30E-07 | 1.44E-04 | 1 | 0.0 |
| Propylene Oxide | 4.76E-05 | 2.18E-02 | 191 | 0.1 |
| Toluene | 1.30E-04 | 5.97E-02 | 523 | 0.3 |
| Xylene | 6.40E-05 | 2.94E-02 | 257 | 0.1 |
| **Total** | | | | **2.6** |

(1) Except PAH, emission factor are same as identified under N-3299-4-0. For PAH, the source identified an emission factor of 1.30E-06
(2) Based on heat input rate of 459 MMBtu/hr.
(3) Based on heat input rate of 4,020,840 MMBtu/year.

Summary:
The combined total single HAP emissions from the units proposed under this project and the existing units are less than 10 tons/yr. Furthermore, the combined total of multiple HAP emissions from the units proposed under this project and the existing emission units are less than 25 tons/yr. Therefore, it is concluded this facility is not a Major Source for air toxics.

**Rule 4001 New Source Performance Standards (NSPS)**

The proposed CTGs are subject to the requirements of this Rule. The applicable subparts are given below:

> 40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines
>
> 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

Detailed discussion on the requirements of each subpart is given in the following section. TID's proposal meets all the requirements of the applicable subparts. Therefore, compliance is expected with the NSPS.

N-3299-4-0, '-5-0, '-6-0

*40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines*

40 CFR Part 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG.

The proposed CTGs are regulated under 40 CFR Part 60 Subpart KKKK. Therefore, they are exempt from the requirements of 40 CFR Part 60 Subpart GG and no further discussion is required.

*40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines*

The requirements of the 40 CFR Part 60, Subpart KKKK apply to a stationary combustion turbine with heat input (at peak load) equal to or greater than 10 MMBtu/hr, and that commenced construction, modification or reconstruction after February 18, 2005. This subpart regulates nitrogen oxide ($NO_X$) and sulfur dioxide ($SO_X$) emissions only.

Each CTG is rated at 523.2 MMBtu/hr (ISO rating) and will be installed after 2/18/05. Therefore, each CTG is subject to the requirements of this subpart.

*Section 60.4320 - Standards for Nitrogen Oxides*

Paragraph (a) states that $NO_X$ emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for $NO_X$. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a heat input at peak load of greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr shall meet a $NO_X$ emissions limit of 25 ppmvd @ 15% $O_2$ or 150 ng/J of useful output (1.2 lb/MWh). This limit is based on 4-hour rolling average or 30-day rolling average as defined in §60.4380(b)(1).

TID has proposed to meet 2.5 ppmvd NOx @ 15% $O_2$ on one-hour rolling average period. TID is expected to meet this limit. Permit condition enforcing this requirement is provided under Rule 2201 (DELs).

*Section 60.4330 - Standards for Sulfur Dioxide*

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or

(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input.

TID has proposed to use PUC-regulated natural gas in each gas turbine that contains 1.0 grain of sulfur per 100 scf (or less). The following condition will ensure compliance with the requirements of this section:

- Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

*Section 60.4335 – $NO_X$ Compliance Demonstration with Water or Steam Injection*

Paragraph (a) states that when a turbine is using water or steam injection to reduce $NO_X$ emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Paragraph (b) states alternatively, you may install, certify, maintain and operate a CEMS consisting of NOx monitor and a diluent gas ($O_2$ or $CO_2$) monitor, to determine the hourly NOx emission rate in ppm or lb/MMBtu.

TID has proposed to install a CEMS for each CTG to monitor NOx and a diluent gas ($O_2$ and $CO_2$), to determine the hourly NOx emission rate.

*Section 60.4340 – $NO_X$ Compliance Demonstration, without Water or Steam Injection*

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

TID has proposed to install a CEMS system as described in §60.4335(b) and 60.4345. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

*Section 60.4345 – CEMS Equipment Requirements*

Paragraph (a) states that each $NO_X$ diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a $NO_X$ diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the $NO_X$ monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the $NO_X$ emission rate for the hour.

Paragraph (c) states that each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

TID has proposed to install and operate a $NO_X$ CEMS to meet the requirements of this section. TID is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. The following conditions will ensure compliance with the requirements of this section:

- The NOx and $O_2$ CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

_Section 60.4350 – CEMS Data and Excess $NO_X$ Emissions_

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both $NO_X$ and diluent monitors, the data acquisition and handling system must calculate and record the hourly $NO_X$ emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$ (or the hourly average $CO_2$ concentration is less than 1.0 percent $CO_2$), a diluent cap value of 19.0 percent $O_2$ or 1.0 percent $CO_2$ (as applicable) may be used in the emission calculations.

(c) Correction of measured $NO_X$ concentrations to 15 percent $O_2$ is not allowed.

(d) If you have installed and certified a $NO_X$ diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average $NO_X$ emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

TID has proposed to monitor the $NO_X$ emissions rate using CEMS. The CEMS system will be used to determine if, and when, any excess $NO_X$ emissions are released to the atmosphere. The CEMS is expected to be operated in accordance with the methods and procedures described above. The following condition will ensure compliance with the requirements of this section:

- The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

*Section 60.4355 – Parameter Monitoring Plan*

This section set forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for $NO_X$ emissions. TID is proposing to install CEMS that will directly measure $NO_X$ emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

*Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content*

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for units located in continental areas and 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for units located in no continental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for no continental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for no continental areas, has potential sulfur emissions of less than less than 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for no continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas or 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for non-continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

TID has proposed to use PUC regulated natural gas that may contain up to 1.0 grain-S/100 scf. Primarily, the natural gas suppliers are able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with this natural gas sulfur content limit. If the sulfur content information is not available from the gas supplier, then the permittee is required to test fuel sulfur content on weekly basis. Upon successful compliance demonstration on 8 week consecutive tests, the test frequency shall be reduced to every six months. If any six-month test shows non-compliance with the sulfur content requirement, weekly testing will resume until eight consecutive weeks show compliance.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) _Fuel oil:_ For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (_i.e._, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) _Gaseous fuel:_ If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) _Custom schedules:_ Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

_Section 60.4380 – Excess $NO_X$ Emissions and Monitor Downtime_

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime.

Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. TID is proposing to monitor $NO_X$ emissions using CEMS. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average $NO_X$ emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average $NO_X$ emission rate" is the arithmetic average of the average $NO_X$ emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average $NO_X$ emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid $NO_X$ emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average $NO_X$ emission rate" is the arithmetic average of all hourly $NO_X$ emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly $NO_X$ emissions rates for the preceding 30 unit operating days if a valid $NO_X$ emission rate is obtained for at least 75 percent of all operating hours.

TID has proposed to emit less than or equal to 2.5 ppmvd NOx @ 15% $O_2$, 4.74 lb-NOx/hr on one-hour rolling average period. Emissions excess of these standards will constitute a violation of the permitted limits. These emissions standards and the averaging period are more stringent that of the ones listed above in section 40 CFR 60.4380(b)(1). Therefore, compliance with this section will be assured by complying with the permitted limit.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: $NO_X$ concentration, CO2 or $O_2$ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes. The following permit condition is placed to assure compliance with this section.

- Monitor Downtime is defined as any unit operating hour in which the data for NOx, or $O_2$ concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)]

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the $NO_X$ emission controls. TID is not proposing to monitor combustion parameters that document proper operation of the $NO_X$ emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

*Section 60.4385 – Excess $SO_X$ Emissions and Monitoring Downtime*

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

TID is expected to follow the definitions and procedures specified above for determining periods of excess $SO_X$ emissions. Compliance is expected with this section.

*Sections 60.4375 and 60.4395 – Reports Submittal*

Section 60.4375(a) states that for each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Section 60.4375(b) states that for each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Section 60.4395 states All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

TID is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

*Section 60.4400 – $NO_X$ Performance Testing*

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent $NO_X$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

TID will be required to source test before the end of the commissioning period and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). The following conditions will ensure compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted before the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

- The following test methods shall be used: $NO_X$ - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

*Section 60.4405 – Initial CEMS Relative Accuracy Testing*

Section 60.4405 states that if you elect to install and certify a $NO_X$-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). TID has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

*Section 60.4410 – Parameter Monitoring Ranges*

Section 60.4410 sets the requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls.

TID is proposing to install CEMS to monitor the $NO_X$ emissions from each gas turbine. They are not proposing to monitor combustion parameters. Therefore, the requirements of this section are not applicable and no further discussion is required.

*Section 60.4415– $SO_X$ Performance Testing*

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

TID is expected to periodically determine the sulfur content of the fuel combusted in the turbine when valid purchase contracts, tariff sheets or transportation contract are not available. The sulfur content will be determined using the methods specified above. The following condition will ensure compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the $SO_2$ concentration in the exhaust stream. TID is not proposing to measure the $SO_2$ in the exhaust stream of the turbine. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Compliance is expected with this Subpart.

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

Pursuant to Section 2.0, "All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein". Therefore, the requirements of this rule apply to this facility. However, there are no applicable requirements for a non-major HAPs source.

As discussed under Rule 2550, TID is not a major HAP source; therefore, no actions are necessary to determine compliance with this rule.

**Rule 4101 Visible Emissions**

District Rule 4101, Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringelmann 1 or equivalent to 20% opacity. The following condition will be placed on each permit:

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

Compliance is expected with this Rule.

**Rule 4102 Nuisance**

Section 4.0 prohibits discharge of air contaminants, which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of operating the proposed boilers provided the equipment is well maintained. Therefore, compliance with this rule is expected. The following condition will be placed on each permit:

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

**California Health & Safety Code 41700**

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. The risk management review (RMR) summary is as follows:

| Category | 4-0 | 5-0 | 6-0 | Project Total | Facility Total |
|---|---|---|---|---|---|
| Prioritization Score | 1.25 | 1.25 | 1.25 | 3.8 | 3.8 |
| Acute Hazard Index | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Chronic Hazard Index | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Maximum Individual Cancer Risk ($10^{-6}$) | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| T-BACT Required? | No | No | No | | |
| Special Conditions Required? | Yes | Yes | Yes | | |

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with each unit is less than 1.0 in a million. In accordance with the District's Risk Management Policy, the unit is approved without toxic Best Available Control Technology (T-BACT). Please refer to Attachment F for health risk assessment.

The District Technical Services Division recommended including the following condition in each permit:

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

**California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")**

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten

(10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Compliance is expected with this Rule.

**Rule 4201 Particulate Matter Concentration**

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

The exhaust flow rate from each CTG will be 661,894 acfm at 850°F. The moisture content in the exhaust is expected to be 12%. Therefore, the exhaust particulate matter emission concentration at 60°F is:

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(2.50\frac{lb-PM}{hr}\right)\left(7{,}000\frac{gr-PM}{lb-PM}\right)\left(\frac{hr}{60\ min}\right)}{\left(661{,}894\frac{ft^3}{min}\right)\left(\frac{460+60}{460+850}\right)(1-0.12)} = 0.001\frac{gr-PM}{dscf}$$

Since 0.001 gr/dscf is less than 0.1 gr/dscf, compliance is expected with this Rule. The following condition will be listed on each permit:

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

**Rule 4301 Fuel Burning Equipment**

The provisions of this rule shall apply to any fuel burning equipment except air pollution control equipment which is exempted according to Section 4.0. Fuel burning equipment is defined as any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer.

CTGs primarily produce power mechanically, i.e. the products of combustion pass directly across the turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft, which rotates and produces electricity. Because the CTG primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment (stated above). Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

**Rule 4703 Stationary Gas Turbines**

Section 2.0 of this rule states that the provisions of this rule apply to all stationary gas turbine systems, which are subject to District permitting requirements, and with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0.

Each gas turbine engine is rated at 54.2 MW nominal ISO rating. Therefore, each unit is subject to the requirements of this rule.

Section 5.1 – $NO_X$ Emission Requirements

Section 5.1.2 - Tier 2 standard of this rule limits the $NO_X$ emissions from simple cycle, stationary gas turbine system rated at greater than 10 MW to 5 ppmvd @ 15% $O_2$ (Standard Option) and 3 ppmv @ 15% $O_2$ (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2003 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option.

TID has proposed to achieve 2.5 ppmvd NOx @ 15% $O_2$ (or less) on a one-hour rolling period for each gas turbine. The following permit condition(s) will ensure on-going compliance with this section:

- Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) – 5.02 lb/hr and **2.5 ppmvd @ 15% O2**; CO – 4.89 lb/hr and 4.0 ppmvd @ 15% O2; VOC (as methane) – 1.40 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 2.50 lb/hr; or SOx (as SO2) – 1.56 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

Section 5.2 – CO Emission Requirements

Section 5.2 - Table 5-4, CO emissions concentration shall not exceed 200 ppmvd @ 15% $O_2$. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. The District practice is to require CO emissions compliance demonstration on 3-hour rolling average period.

TID has proposed to achieve 4.0 ppmvd CO @ 15% $O_2$ on 3-hour rolling average. The following permit condition(s) will ensure on-going compliance with this section:

- Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) – 5.02 lb/hr and 2.5 ppmvd @ 15% O2; CO – 4.89 lb/hr and **4.0 ppmvd @ 15% O2**; VOC (as methane) – 1.40 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 2.50 lb/hr; or SOx (as SO2) – 1.56 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

Section 5.3 – Transitional Operation Periods

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during a transitional operation period, which includes bypass transition period, primary re-ignition period, reduced load period, start-up or shutdown (each term is defined in Section 3.0 of Rule 4703), provided an operator complies with the requirements of section 5.3.1 which are outlined below:

5.3.1.1 The duration of each startup or each shutdown shall not exceed two hours.
5.3.1.2 For each bypass transition period, the requirements specified in Section 3.2 shall be met.
5.3.1.3 For each primary re-ignition period, the requirements specified in Section 3.20 shall be met.
5.3.1.4 Each reduced load period shall not exceed one hour.

TID has proposed to complete each startup or each shutdown within one-hour for each gas turbine. This proposal meets the requirements of section 5.3.1.1 of this Rule. The following condition will be placed on each permit:

- Startup of this gas turbine system shall not exceed one-hour per event. [District Rules 2201 and 4703]

- Shutdown of this gas turbine system shall not exceed one-hour per event. [District Rule 2201 and 4703]

The exhaust from each CTG is vented through an emission control system. There is no bypass exhaust stack on these units. Therefore, these units are not required to meet any bypass transition period requirements.

The proposed gas turbines are not equipped with dry low-NOx technology. Therefore, these units are not required to meet any primary re-ignition period requirements.

The proposed gas turbines will not have exhaust gas diverter gates and therefore, they will not have any "reduced load periods".

Section 5.3.2 requires that emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during each transitional period (in this case it would be startup, shutdown, and reduced load period). The following condition will be listed on each permit:

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2]

Section 6.2 - Monitoring and Recordkeeping

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for $NO_X$ and oxygen, or install and maintain APCO-approved alternate monitoring.

TID has proposed to use CEMS to determine $NO_X$ and oxygen content in the exhaust stream for each gas turbine. Thus, the requirements of this section are satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas $NO_X$ control devices. Each gas turbine will be equipped with its own SCR system to reduce $NO_X$ emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas $NO_X$ emissions. This section is not applicable to this project.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. TID will be required to maintain all records for at least five years and make them available to the APCO upon request. The following condition will placed on each permit:

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure $NO_X$ output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for $NO_X$ available or when the continuous emissions monitoring system is not operating properly. The following condition will be placed on each permit:

- The owner or operator shall submit to the District information correlating the $NO_X$ control system operating parameters to the associated measured $NO_X$ output. The information must be sufficient to allow the District to determine compliance with the $NO_X$ emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5]

Section 6.2.6 requires the owner or operator to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. The proposed gas turbines will not have exhaust gas diverter gates and therefore, these turbines will not have any "reduced load periods".

Section 6.2.7 requires the owner or operator shall maintain a stationary gas turbine system log for units exempt under Section 4.2 of this Rule. The proposed gas turbines do not qualify for exemption under Section 4.2 of this Rule. Therefore, no further discussion is required.

Section 6.2.8 requires the operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

Section 6.2.11 requires the operator of a unit shall keep records of the date, time and duration of each bypass transition period and each primary re-ignition period.

TID will be required to maintain records of the items listed in above applicable sections. The following conditions will be placed on each permit:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, date/time and duration of each start-up and each shutdown event. [District Rule 4703, 6.2.6, 6.2.8, 6.2.11]

<u>Sections 6.3 and 6.4 - Compliance Testing</u>

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas $NO_X$ and CO concentrations.

The gas turbine system proposed by the facility is subject to the provisions of Section 5.0 of this rule. Therefore, this system is required to be tested annually to ensure compliance with $NO_X$ and CO concentrations. The following condition will be placed on each permit:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted before the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. Each gas turbine will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner in both "on" and "off" configurations. The proposed gas turbines will not be equipped with auxiliary burners (duct burners). Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.4 states that the facility must demonstrate compliance annually with the $NO_X$ and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: $NO_X$ - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Compliance is expected with this Rule.

**Rule 4801 Sulfur Compounds**

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

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

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

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

**Rule 8011 General Requirements**
**Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities**
**Rule 8031 Bulk Materials**
**Rule 8041 Carryout And Trackout**
**Rule 8051 Open Areas**
**Rule 8061 Paved and Unpaved Roads**
**Rule 8071 Unpaved Vehicle/Equipment Traffic Areas**

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

**California Environmental Quality Act (CEQA)**

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

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

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

**40 CFR Part 51 Appendix S Requirements for $PM_{2.5}$**

40 CFR 51 Appendix S requirements are applicable to new major $PM_{2.5}$ sources and federal major modifications for $PM_{2.5}$. The significance thresholds are as follows:

| | |
|---|---|
| $PM_{2.5}$ major source threshold | 100 ton/year |
| $PM_{2.5}$ federal major modification threshold | 10 ton/year |

As discussed in Section VII.D.2 of this document, this facility is not a Major Source for $PM_{10}$ emissions. As $PM_{2.5}$ is a subset of $PM_{10}$, and the $PM_{2.5}$ Major Source threshold is greater than the $PM_{10}$ Major Source threshold, this facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, Appendix S requirements for $PM_{2.5}$ are not applicable and no further discussion is required.

## IX. RECOMMENDATION

Compliance with all applicable prohibitory rules and regulations is expected.
Recommend issuing the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

**By issuing this FDOC, we are certifying that complete emissions offsets for the proposed facility have been identified and will be obtained by the applicant within the time required by the district's rules, per PRC 25523 (d)(2).**

## X. BILLING INFORMATION

| ATC Permit | Fee Schedule | Fee Description | Previous Fee Schedule |
|---|---|---|---|
| N-3299-4-0 | 3020-08B G | 54,200 kW | None |
| N-3299-5-0 | 3020-08B G | 54,200 kW | None |
| N-3299-6-0 | 3020-08B G | 54,200 kW | None |

**ATTACHMENT A**
**FDOC CONDITIONS**

# Permit Unit Requirements for N-3299-4-0, '-5-0 and '-6-0 (ALL THREE TURBINES HAVE IDENTICAL PERMIT CONDITIONS)

Equipment Description:

54.2 MW NOMINAL (ISO) RATING SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM CONSISTING OF A 523.2 MMBTU/HR (AT NOMINAL ISO MW RATING) GENERAL ELECTRIC, AERO DERIVATIVE, MODEL LM6000 PG SPRINT, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH A WATER SPRAY PREMIXED COMBUSTION SYSTEM, AN OXIDATION CATALYST AND A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH AMMONIA INJECTION

Permit Conditions:

1. The permittee shall not begin actual on-site construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act] N

2. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Y

3. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Y

4. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100] N

5. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100] N

6. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102] N

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102] N

8. Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Y

9. 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] Y

10. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080] Y

11. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201] Y

12. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201] Y

13. Emission rates from the gas turbine system during the commissioning period shall not exceed any of the following limits: NOx (as NO2) - 40.40 lb/hr and 969.6 lb/day; VOC (as CH4) - 8.41 lb/hr and 201.8 lb/day; CO - 40.00 lb/hr and 704.6 lb/day; PM10 - 2.50 lb/hr and 60.0 lb/day; or SOx (as SO2) - 1.56 lb/hr and 37.4 lb/day. [District Rule 2201] Y

14. During commissioning period, NOx and CO emission rate shall be monitored using installed and calibrated CEMS. [District Rule 2201] Y

15. The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201] Y

16. During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the gas turbine system on hourly and daily basis. [District Rule 2201] Y

17. Startup of this gas turbine system shall not exceed one-hour per event. [District Rules 2201 and 4703] Y

18. Shutdown of this gas turbine system shall not exceed one-hour per event. [District Rules 2201 and 4703] Y

19. During all types of operation (with an exception of ammonia injection tuning prior to the initial source test during the commissioning period), including startup and shutdown periods, ammonia injection into the SCR system shall occur once the minimum temperature at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum catalyst face temperature shall be determined during the final design phase of this project and shall be submitted to the District at least 30 days prior to commencement of construction. [District Rule 2201] Y

20. The District shall administratively add the minimum temperature limitation established pursuant to the above condition in the final Permit to Operate. The District may administratively modify the temperature as necessary following any replacement of the SCR catalyst material. [District Rule 2201] Y

21. During start-up or shutdown period, the emissions shall not exceed any of the following limits: NOx (as NO2) - 25.00 lb/hr; CO - 40.00 lb/hr; VOC (as methane) - 2.00 lb/hr; PM10 - 2.50 lb/hr; SOX (as SO2) - 1.56 lb/hr; or NH3 - 7.44 lb/hr. [District Rules 2201 and 4703] Y

22. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29] Y

23. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status ending when the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26] Y

24. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2] Y

25. Except during startup and shutdown periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 5.02 lb/hr and 2.5 ppmvd @ 15% O2; CO - 4.89 lb/hr and 4.0 ppmvd @ 15% O2; VOC (as methane) - 1.40 lb/hr and 2.0 ppmvd @ 15% O2; PM10 - 2.50 lb/hr; or SOx (as SO2) - 1.56 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703] Y

26. NH3 emissions shall not exceed 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period. [District Rule 2201] Y

27. Each 3-hour rolling average period will be compiled from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour rolling average for ammonia slip will commence on the

hour. The twenty-four hour rolling average shall be calculated using the most recent twenty-four one-hour periods. [District Rule 2201] Y

28. Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) - 160.4 lb/day; CO - 187.6 lb/day; VOC - 34.8 lb/day; PM10 - 60.0 lb/day; SOx (as SO2) - 37.4 lb/day, or NH3 - 178.6 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201] Y

29. Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: NOx (as NO2) - 120.5 lb/day; CO - 117.4 lb/day; VOC - 33.6 lb/day; PM10 - 60.0 lb/day; SOx (as SO2) - 37.4 lb/day, or NH3 - 178.6 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201] Y

30. Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)] Y

31. NOx (as NO2) emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 11,635 lb; 2nd quarter: 11,764 lb; 3rd quarter: 11,894 lb; 4th quarter: 11,894 lb. [District Rule 2201] Y

32. CO emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 12,728 lb; 2nd quarter: 12,869 lb; 3rd quarter: 13,011 lb; 4th quarter: 13,011 lb. [District Rule 2201] Y

33. VOC emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 2,794 lb; 2nd quarter: 2,825 lb; 3rd quarter: 2,856 lb; 4th quarter: 2,856 lb. [District Rule 2201] Y

34. NH3 emissions from the SCR system associated with this gas turbine system shall not exceed any of the following: 1st quarter: 15,181 lb; 2nd quarter: 15,349 lb; 3rd quarter: 15,517 lb; 4th quarter: 15,517 lb. [District Rule 2201] Y

35. PM10 emissions from this gas turbine system shall not exceed any of the following: 1st quarter: 5,400 lb; 2nd quarter: 5,461 lb; 3rd quarter: 5,520 lb; 4th quarter: 5,520 lb. [District Rule 2201] Y

36. SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 3,183 lb; 2nd quarter: 3,219 lb; 3rd quarter: 3,255 lb; 4th quarter: 3,255 lb. [District Rule 2201] Y

37. A water injection system, a selective catalytic reduction (SCR) system and an oxidation catalyst shall serve this gas turbine system. [District Rule 2201] Y

38. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201] Y

39. 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] Y

40. Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081] Y

41. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted before the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOX and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081] Y

42. Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted before the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)] Y

43. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Y

44. The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, 40 CFR 60.4400(1)(i)] Y

45. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)] Y

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

47. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 4703] Y

48. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)] Y

49. The NOx and O2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)] Y

50. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)] Y

51. The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350] Y

52. In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Y

53. The owner/operator shall perform a RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Y

54. The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Y

55. Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080] Y

56. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080] Y

57. The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.7(b)] Y

58. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] Y

59. Monitor Downtime is defined as any unit operating hour in which the data for NOx, or O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)] Y

60. The owner or operator shall maintain records of the following items: 1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup and or shutdown of the gas turbine system occurs, 2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup and or shutdown of the gas turbine system does not occur, 3) quarterly emissions, in pounds, for each pollutant listed in this permit. [District Rule 2201] Y

61. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, date/time and duration of each start-up and each shutdown event. [District Rule 2201 and 4703, 6.2.6, 6.2.8, 6.2.11] Y

62. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4] Y

63. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395] Y

64. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5] Y

65. Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 34,905 lb, 2nd quarter: 35,292 lb, 3rd quarter: 35,682 lb, and 4th quarter: 35,682 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Y

66. NOx ERC S-3113-2 (or a certificate split from this certificate) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Y

67. Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 6,113 lb, 2nd quarter: 6,113 lb, 3rd quarter: 6,114 lb, and 4th quarter: 6,114 lb. Offsets shall be

provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Y

68. VOC ERC C-1008-1 (or a certificate split from this certificate) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Y

69. Prior to operating under ATCs N-3299-4-0, N-3299-5-0 and N-3299-6-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 13,506 lb, 2nd quarter: 13,507 lb, 3rd quarter: 13,507 lb, and 4th quarter: 13,507 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Y

70. SOx ERC S-3129-5 (or a certificate split from this certificate) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Y

71. The District has authorized to use SOx reductions to offset emissions increase in PM10 at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201] Y

72. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021] Y

73. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021] Y

74. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 or Rule 8011. [District Rules 8011 and 8021] Y

75. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless

specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051] Y

76. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061] Y

77. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071] Y

78. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071] Y

79. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071] Y

80. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071] Y

81. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031 and 8071] Y

82. The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72] Y

83. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Y

84. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75] Y

85. The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73] Y

86. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Y

87. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72] Y

88. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73] Y

89. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Y

90. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72] Y

91. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77] Y

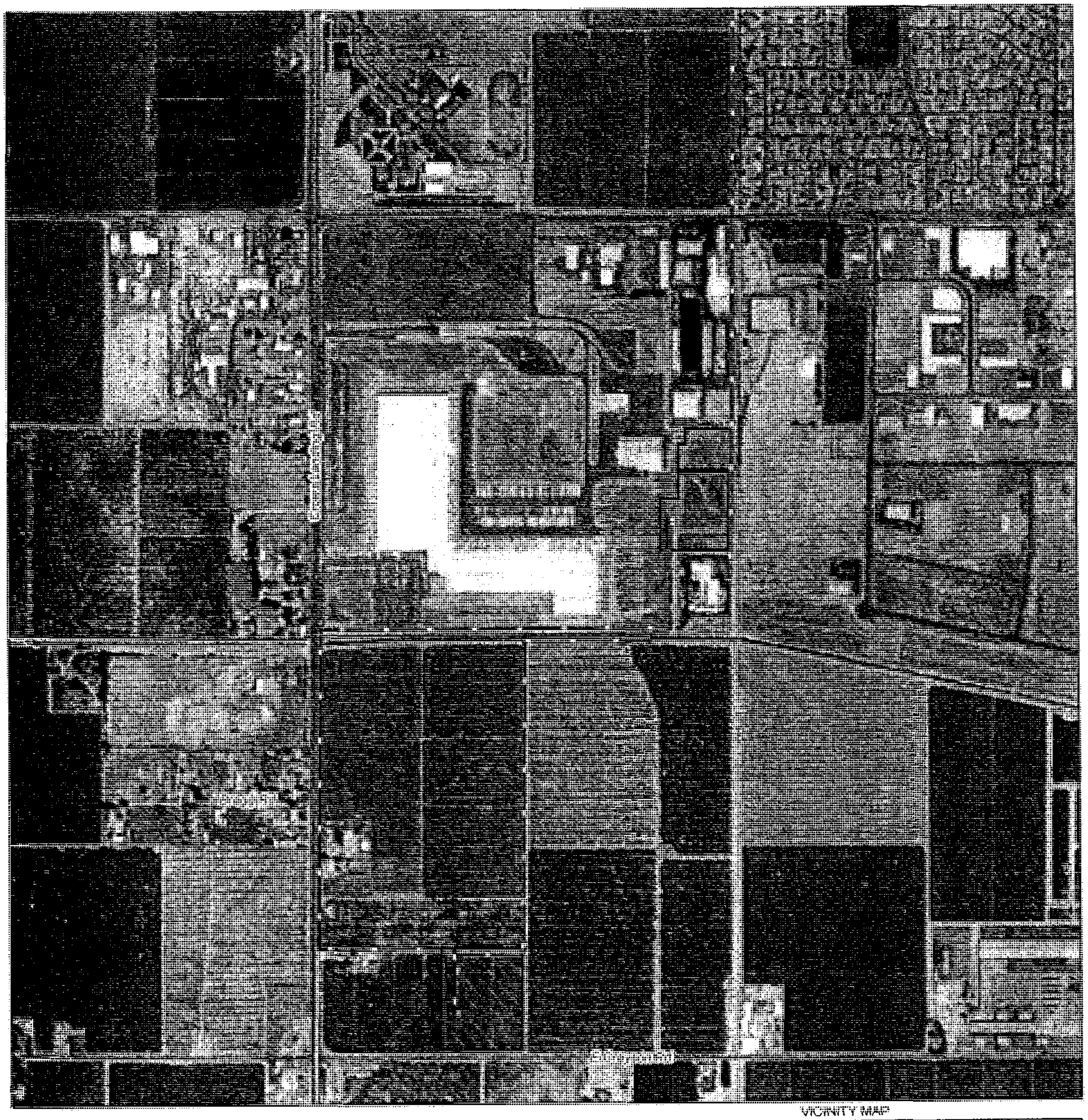
92. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77] Y

93. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72] Y

94. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75] Y

95. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Y
Y

# ATTACHMENT B
# PROJECT LOCATION AND SITE PLAN



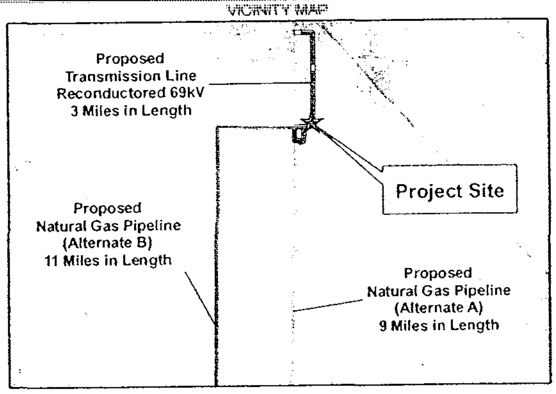
LEGEND

- Natural Gas Pipeline (Alternate A)
- Natural Gas Pipeline (Alternate B)
- 115-kV Circuit 1 Line (Corridor 1)
- 115-kV Circuit 2 Line (Corridor 2)
- Transmission Line Reconductored 69kV (Corridor 3)
- Proposed Grayson Substation
- Laydown Area
- Project Site

N

0 500 1,000
Feet

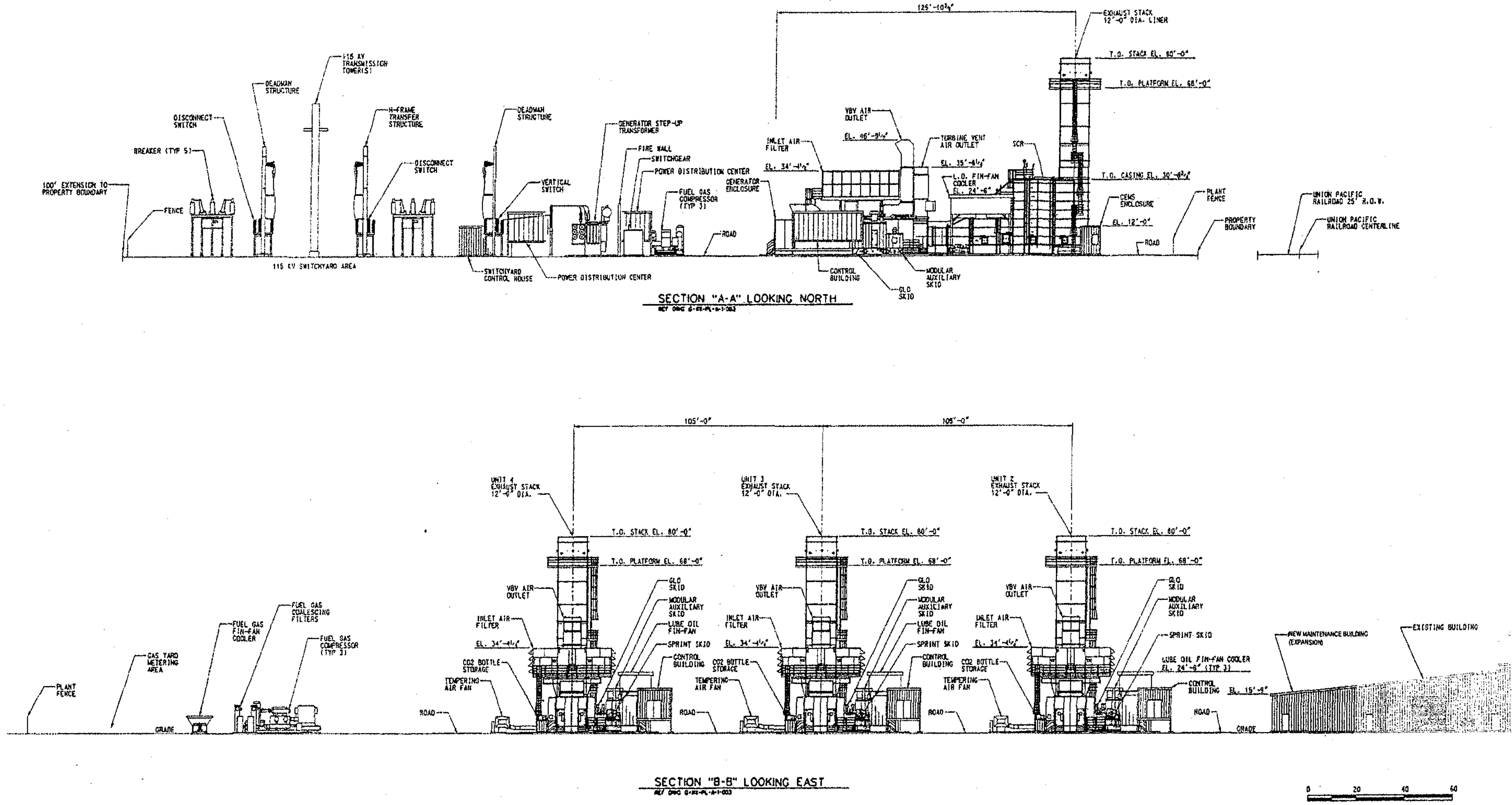
VICINITY MAP




This map was compiled from various scale source data and maps and is intended for use as only an approximate representation of actual locations.

**FIGURE 2**
**SITE LOCATION**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

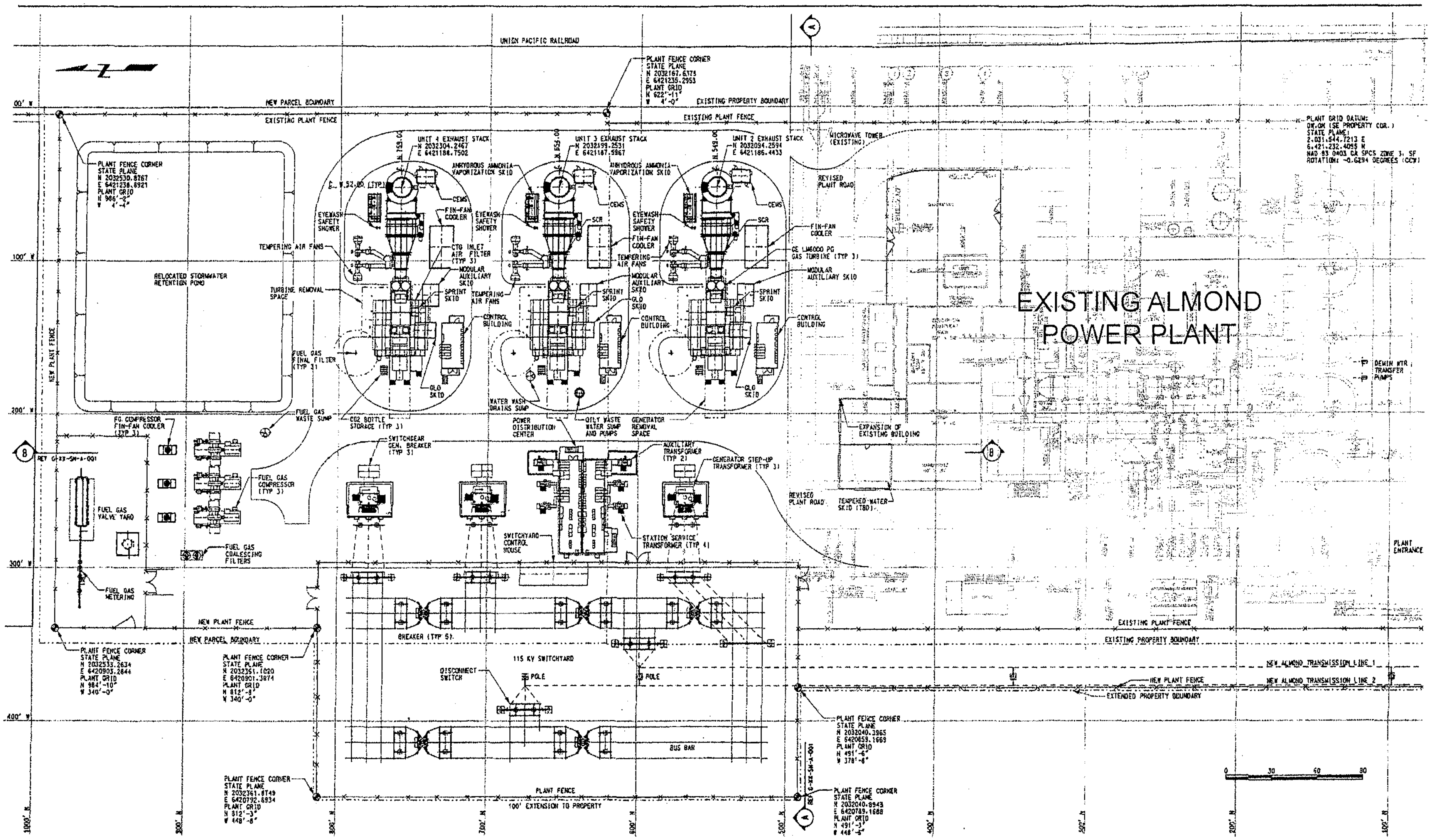
**CH2MHILL**




Source: CH2M HILL, Drawing G-XX-SN-1-A-001, Revision E

**FIGURE 4R**
**ELEVATIONS**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

**CH2MHILL**




Notes:
"Shaded" facilities indicate the existing Almond Power Plant
Dark lines indicate the proposed A2PP

Source: CH2M HILL, Drawing G-XX-PL-1-A-003, Revision F

**FIGURE 3R**
**GENERAL ARRANGEMENT**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

**CH2MHILL**

# ATTACMENT C
# CTG COMMISSIONG PERIOD EMISSIONS DATA

**Table 5.1B-7a**
**TID Almond 2 Power Plant**
**Gas Turbine Commissioning Profile**

| Operating Mode | Hours of Operation(1) | Fuel Use MMBtu/hr (2) (HHV) | Emission Factors (lbs/MMBtu) NOx(3) | CO(4) | VOC(5) | PM10(6) | SOx(7) | Hourly Emissions (lbs/hr) NOx | CO | VOC | PM10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Turbine 1 - FSNL | 4 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 2 - FSNL | 4 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 3 - FSNL | 4 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 1 - Min. Load, no SCR or ox cat | 20 | 111.0 | 0.15288 | 0.1764 | 0.0202 | n/a | 0.0028 | 16.97 | 19.58 | 2.24 | 2.5 |
| Turbine 2 - Min. Load, no SCR or ox cat | 20 | 111.0 | 0.15288 | 0.1764 | 0.0202 | n/a | 0.0028 | 16.97 | 19.58 | 2.24 | 2.5 |
| Turbine 3 - Min. Load, no SCR or ox cat | 20 | 111.0 | 0.15288 | 0.1764 | 0.0202 | n/a | 0.0028 | 16.97 | 19.58 | 2.24 | 2.5 |
| Turbine 1 - FSNL (if necessary) | 24 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 2 - FSNL (if necessary) | 24 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 3 - FSNL (if necessary) | 24 | 111.0 | 0.3640 | 0.2646 | 0.0758 | n/a | 0.0028 | 40.40 | 29.36 | 8.41 | 2.5 |
| Turbine 1 - Multiple Load - Full SCR/ox cat | 48 | 554.9 | 0.05915 | 0.0088 | 0.0025 | n/a | 0.0028 | 32.82 | 4.89 | 1.40 | 2.5 |
| Turbine 2 - Multiple Load - Full SCR/ox cat | 48 | 554.9 | 0.05915 | 0.0088 | 0.0025 | n/a | 0.0028 | 32.82 | 4.89 | 1.40 | 2.5 |
| Turbine 3 - Multiple Load - Full SCR/ox cat | 48 | 554.9 | 0.05915 | 0.0088 | 0.0025 | n/a | 0.0028 | 32.82 | 4.89 | 1.40 | 2.5 |
| Total = | 288 | | | | | | | | | | |

Notes:
(1) Hours of Operation - based on information supplied by MID for the Ripon project
(2) Fuel Use
- No Load test: Based on 20% of maximum heat input rating
- Minimum Load test: Based on 20% of maximum heat input rating
- Multiple Load test: Based on 100% of maximum heat input rating
(3) NOx Emission Factors
- No Load test: Based on 100 ppm @ 15% O2.
- Minimum Load test: Based on maximum uncontrolled emission rate of 42 ppm @ 15% O2
- Multiple Load Full SCR/ox cat test: Based on NOx emission levels at the midway point between 30 ppm and 2.5 ppm @ 15% O2
(4) CO Emission Factors
- No Load test: Based on maximum uncontrolled emission rate of 30 times controlled level, or 120 ppm @ 15% O2
- Minimum Load test: Based on maximum uncontrolled emission rate of 20 times controlled level, or 80 ppm @ 15% O2
- Multiple Load Full SCR/ox cat test: Based on unit meeting the project design level of 4 ppm @ 15% O2 with oxidation catalyst installed and operating
(5) VOC Emission Factors
- No Load test: Based on maximum uncontrolled emission rate of 30 times controlled level, or 60 ppm @ 15% O2
- Minimum Load test: Based on maximum uncontrolled emission rate of 8 times controlled level, or 16 ppm @ 15% O2
- Multiple Load Full SCR/ox cat test: Based on unit meeting the project design level of 2 ppm @ 15% O2 with oxidation catalyst installed and operating
(6) PM10 Emission Factors
- For all tests, based on project design PM10 level of 2.5 lbs/hr.
(7) SOx Emission Factors
- For all tests, based on annual average natural gas sulfur content of 1.0 gr/100 scf

ATTACHMENT D
SJVAPCD BACT GUIDELINE 3.4.7

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 3.4.7*

Last Update: 10/1/2002

### Gas Turbine - = or > 50 MW , Uniform Load, without Heat Recovery

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | 6.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal). | | |
| NOx | 5.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal). | 1. 2.5 ppmvd** @ 15% O2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR), or equal).<br>2. 3.0 ppmvd** @ 15% O2, based on a three-hour average (high temp SCR, or equal). | |
| PM10 | Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC regulated natural gas, LPG, or non-PUC-regulated gas with < 0.75 grams S/100 dscf. | | |
| SOx | PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with = or < 0.75 grams S/100 dscf. | | |
| VOC | 2.0 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal). | 1. 0.6 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst).<br>2. 1.3 ppmvd** @ 15% O2, based on a three-hour average (Oxidation catalyst, or equal). | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

# ATTACHMENT E
# TOP-DOWN BACT ANALYSIS

# I. $NO_X$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.7 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 5.0 ppmvd @ 15% $O_2$ based on a three-hour average (high temperature selective catalytic reduction, or equal)

Technologically Feasible

- 2.5 ppmvd @ 15% $O_2$ based on a one-hour average (high temperature selective catalytic reduction, or equal)
- 3.0 ppmvd @ 15% $O_2$ based on a one-hour average (high temperature selective catalytic reduction, or equal)

Alternate Basic Equipment

None

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. 2.5 ppmvd @ 15% $O_2$ based on a one-hour average (high temperature selective catalytic reduction, or equal)
2. 3.0 ppmvd @ 15% $O_2$ based on a one-hour average (high temperature selective catalytic reduction, or equal)

**Step 4 - Cost Effectiveness Analysis**

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use of water injection and a selective catalytic reduction system to achieve less than or equal to 2.5 ppmv NOx @ 15% $O_2$ based on one-hour average during steady-state period. This is the most stringent emission limit listed in Step 3 above. Therefore, in accordance with District policy APR-1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for each gas turbine system is to achieve 2.5 ppmvd @ 15% $O_2$ or less on one-hour rolling average period.

TID has proposed to achieve 2.5 ppmvd @ 15% $O_2$ or less on one-hour average period, Therefore, BACT requirements are satisfied.

## II. CO Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.7 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 6.0 ppmv @ 15% $O_2$ based on three-hour rolling average (oxidation catalyst or equal)

Technologically Feasible

None

Alternate Basic Equipment

None

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. 6.0 ppmv @ 15% $O_2$ based on three-hour rolling average (oxidation catalyst or equal).

**Step 4 - Cost Effective Analysis**

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use of an oxidation catalyst to achieve less than or equal to 4.0 ppmvd CO @ 15% $O_2$ on three-hour rolling average, excluding startup and shutdown. The proposed limit is more stringent than the emission limits listed in Step 3 above. Therefore, in accordance with District policy APR-1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for each gas turbine system is to achieve 4.0 ppmvd @ 15% $O_2$ or less on three-hour rolling average period.

TID has proposed to achieve 4.0 ppmvd @ 15% $O_2$ or less on three-hour rolling average basis. Therefore, BACT requirements are satisfied.

## III. VOC Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.7 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 2.0 ppmvd VOC @ 15% $O_2$ based on a three-hour average (oxidation catalyst or equal)

Technologically Feasible

- 0.6 ppmvd VOC @ 15% $O_2$ based on a three-hour average (oxidation catalyst or equal)
- 1.3 ppmvd VOC @ 15% $O_2$ based on a three-hour average (oxidation catalyst or equal)

Alternate Basic Equipment

None

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. 0.6 ppmvd @ 15% $O_2$ based on a 3-hour rolling average
2. 1.3 ppmvd @ 15% $O_2$ based on a 3-hour rolling average
3. 2.0 ppmvd @ 15% $O_2$ based on a 3-hour rolling average

**Step 4 - Cost Effectiveness Analysis**

**Option 1: 0.6 ppmvd @ 15% $O_2$ based on a three-hour average**

TID's consultant has supplied the information to purchase, install, operate and maintain the oxidation catalyst to achieve VOC (as $CH_4$) concentration of 0.6 ppmvd @ 15% $O_2$. The basic equipment cost is for three oxidation catalyst systems for the proposed project.

Direct Capital Costs (DC)

| | | | |
|---|---|---|---|
| Purchase Equipment Costs (PE) | | | |
| Basic Equipment | A | $ 1,408,000 | catalyst vendor |
| Instrumentation: included | B | -- | OAQPS |
| Taxes | 0.08(A+B) | $ 112,640 | Sales tax |
| Freight | 0.03(A+B) | $ 42,240 | OAQPS[3] |
| | PE(Total): | $ 1,562,880 | |

| | | | |
|---|---|---|---|
| Direct Installation Costs (DI) | | | |
| Foundation and supports | 0.08 PE | $ 125,030 | OAQPS |
| Handling and Erection | 0.14 PE | $ 218,803 | OAQPS |
| Electrical | 0.04 PE | $ 62,515 | OAQPS |
| Piping | 0.02 PE | $ 31,258 | OAQPS |
| Insulation | 0.01 PE | $ 15,629 | OAQPS |
| Painting | 0.01 PE | $ 15,629 | OAQPS |
| | DI (Total): | $ 468,864 | |

Indirect Costs (IC)

| | | | |
|---|---|---|---|
| Engineering | 0.10 PE | $ 156,288 | OAQPS |
| Construction and Field Expenses | 0.05 PE | $ 78,144 | OAQPS |
| Contractor Fees | 0.10 PE | $ 156,288 | OAQPS |
| Start-up | 0.02 PE | $ 31,258 | OAQPS |
| Performance Testing | 0.01 PE | $ 15,629 | OAQPS |
| Contingencies | 0.03 PE | $ 46,886 | OAQPS |
| | IC (Total): | $ 484,493 | |

Total Capital Investment (TCI = PE + DI + IC) $ 2,516,237

[3] OAQPS means Office of Air Quality Planning and Standards

TCI is annualized over 10 years assuming 10% interest. The following formula is used to determine the annualized cost:

$$ATCI = (P)\left[\frac{(i)(1+i)^n}{(1+i)^n - 1}\right]$$

Where:

ATCI: Annualized total capital investment of the control equipment
P: Present value of the control equipment
I: Interest rate (District policy is to use 10%)
n: Equipment life (District policy is to use 10 years)

$$ATCI = (\$2,516,237)\left[\frac{(0.1)(1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \frac{\$409,506}{yr}$$

<u>Direct Annual Costs (DAC)</u>

Performance Loss: Per TID, due to this oxidation catalyst, the performance loss in electrical energy output would be 240 kW, or 0.443%[4] of the total output of 54,200 kW. Using $0.0696 per kWH, the annual loss to the facility from three turbines would be:

Performance Loss = (3 units)(0.443%)(54,200 kW)($0.0696/kWH)(8,760 H/yr)
= $439,175/yr

Catalyst Replacement: The catalyst must be replaced every 5 years. This means, the catalysts may need to be replaced at 5th year and $10^{th}$ year in a 10 year period. The present value for catalyst replacements over a period of 10 years is calculated as follows:

$$Pn = \text{Cost of Catalyst}\left(\frac{1}{(i+1)^n}\right)$$

Where:

Cost of Catalysts = $281,600
Interest Rate (i), assumed to be 10%.
n = lifetime of the equipment

When n= 5,

[4] (240 kW/54,200 kW) × 100 = 0.443%

$$P_5 = 281{,}600\left(\frac{1}{(0.1+1)^5}\right) = \$174{,}851$$

Similarly, when n = 10 in the above equation then

$P_{10}$ = $108,569

Equivalent Annual Cost of Catalysts replacements:

$$A = (P)\left[\frac{(i)(1+i)^n}{(1+i)^n - 1}\right]$$

Where:

A: Equivalent annual capital cost of the control equipment
P: Present value of the control equipment
I: Interest rate (District policy is to use 10%)
n: Equipment life (District policy is to use 10 years)

$$A = (174{,}851 + 108{,}569)\left[\frac{(0.1)(1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \frac{\$46{,}125}{yr}$$

Total Direct Annual Cost (DAC) = $439,175/yr + $46,125/yr
= $485,300/yr

Indirect Annual Costs (IAC)

| | |
|---|---|
| Overhead (not included) | |
| Administrative (0.02 TCI) | = $50,325 |
| Insurance (0.01 TCI) | = $25,162 |
| Property Tax (0.01 TCI) | = $25,162 |
| Total (IAC) | = $100,649 |

Total Cost:

The total cost to purchase, install, maintain and operate the oxidation systems for three gas turbines would be:

Total = ATCI ($/yr) + DAC ($/yr) + IAC ($/yr)
= $409,506/yr + $485,300 + $100,649/yr
**= $995, 455/yr**

MCET:

Oxidation catalyst reduces CO emissions as well as VOC emissions. Thus, multi-pollutant cost effectiveness threshold (MCET) must be determined for comparison with the total cost of $995,455/yr.

*VOC*

VOC emissions of 5[5] ppmv @ 15% $O_2$ is assumed to be the industry standard for the gas turbines. The emission reductions from the industry standard to the technologically feasible option of 0.6 ppmv @ 15% $O_2$ are determined in the following section.

VOC emissions using 2.0 ppmvd @ 15% $O_2$ are 10,601 lb/yr-unit during baseload period, and 730 lb/yr-unit during startup/shutdown periods. These emissions rates are taken from Section VII of this document.

Using this information, VOC concentration of 5 ppmvd @ 15% $O_2$ would be:

= (5 ppmvd/2 ppmvd)(10,601 lb-VOC/yr-unit)(3 units) + (730 lb-VOC/yr-unit)(3 units)
= 81,698 lb-VOC/yr

Similarly, VOC emissions using 0.6 ppmvd @ 15% $O_2$ would be:

= (0.6 ppmvd/2 ppmvd)(10,601 lb-VOC/yr-unit)(3 units) + (730 lb-VOC/yr-unit)(3 units)
= 11,731 lb-VOC/yr

VOC Reductions = 81,698 lb-VOC/yr – 11,731 lb-VOC/yr
= 69,967 lb-VOC/yr

*CO*

CO emissions of 25[4] ppmv @ 15% $O_2$ is assumed to be the industry standard for the gas turbines. Per TID's consultant, CO emissions are expected to be 1.0 ppmvd @ 15% $O_2$ with use of this oxidation catalyst.

CO emissions using 4.0 ppmvd @ 15% $O_2$ are 37,019 lb/yr-unit during baseload period, and 14,600 lb/yr-unit during startup/shutdown periods. These emissions rates are taken from Section VII of this document. Using this information, CO emissions using 25 ppmvd @ 15% $O_2$ would be:

= (25 ppmvd/4 ppmvd)(37,019 lb-CO/yr-unit)(3 units) + (14,600 lb-CO/yr-unit)(3 units)
= 737,906 lb-CO/yr

---

[5] Referenced from the presentation of EmeraChem Power, June 26, 2008

Similarly, CO emissions using 1.0 ppmvd @ 15% $O_2$ would be:

= (1.0 ppmvd/4 ppmvd)(37,019 lb-CO/yr-unit)(3 units) + (14,600 lb-CO/yr-unit)(3 units)
= 71,564 lb-CO/yr

CO Reductions = 737,906 lb-CO/yr – 71,564 lb-CO/yr
= 666,342 lb-CO/yr

_MCET_

Cost effectiveness threshold for VOC and CO are $17,500/ton and $300/ton respectively. These thresholds are used to determine the MCET for this project.

MCET = ($17,500/ton)(69,967 lb-VOC/yr)(ton/2,000 lb)
+ ($300/ton)(666,342 lb-CO/yr)(ton/2,000 lb)
**= $712,163**

The total cost to purchase, install, maintain and operate the oxidation systems for three gas turbines would be $995,455/yr, which is greater than the multi-pollutant cost effectiveness threshold of $712,163. Therefore, this option of reducing VOC emissions to 0.6 ppmvd @ 15% $O_2$, is not cost-effective and is removed from consideration at this time.

**Option 2: 1.3 ppmvd @ 15% $O_2$ based on a three-hour average**

TID's consultant has supplied the information to purchase, install, operate and maintain the oxidation catalyst to achieve VOC (as $CH_4$) concentration of 1.3 ppmvd @ 15% $O_2$. The basic equipment cost is for three oxidation catalyst systems for the proposed project.

Direct Capital Costs (DC)

| | | | |
|---|---|---|---|
| Purchase Equipment Costs (PE) | | | |
| Basic Equipment | A | $ 824,000 | catalyst vendor |
| Instrumentation: included | B | -- | OAQPS |
| Taxes | 0.08(A+B) | $ 65,920 | Sales tax |
| Freight | 0.03(A+B) | $ 24,720 | OAQPS |
| | PE(Total): | $ 914,640 | |

| | | | |
|---|---|---|---|
| Direct Installation Costs (DI) | | | |
| Foundation and supports | 0.08 PE | $ 73,171 | OAQPS |
| Handling and Erection | 0.14 PE | $ 128,050 | OAQPS |
| Electrical | 0.04 PE | $ 36,586 | OAQPS |
| Piping | 0.02 PE | $ 18,293 | OAQPS |

| | | | |
|---|---|---|---|
| Insulation | 0.01 PE | $ 9,146 | OAQPS |
| Painting | 0.01 PE | $ 9,146 | OAQPS |
| | DI (Total): | $ 274,392 | |

Indirect Costs (IC)

| | | | |
|---|---|---|---|
| Engineering | 0.10 PE | $ 91,464 | OAQPS |
| Construction and Field Expenses | 0.05 PE | $ 45,732 | OAQPS |
| Contractor Fees | 0.10 PE | $ 91,464 | OAQPS |
| Start-up | 0.02 PE | $ 18,293 | OAQPS |
| Performance Testing | 0.01 PE | $ 9,146 | OAQPS |
| Contingencies | 0.03 PE | $ 27,439 | OAQPS |
| | IC (Total): | $ 283,538 | |

Total Capital Investment (TCI = PE + DI + IC) $ 1,472,570

TCI is annualized over 10 years assuming 10% interest. The following formula is used to determine the annualized cost:

$$ATCI = (P)\left[\frac{(i)(1+i)^n}{(1+i)^n - 1}\right]$$

Where:

ATCI: Annualized total capital investment of the control equipment
P: Present value of the control equipment
I: Interest rate (District policy is to use 10%)
n: Equipment life (District policy is to use 10 years)

$$ATCI = (\$1,472,570)\left[\frac{(0.1)(1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \frac{\$239,654}{yr}$$

Direct Annual Costs (DAC)

Performance Loss: Per TID, due to this oxidation catalyst, the performance loss in electrical energy output would be 180 kW, or 0.332%[6] of the total output of 54,200 kW. Using $0.0696 per kWH, the annual loss to the facility from three turbines would be:

Performance Loss = (3 units)(0.332%)(54,200 kW)($0.0696/kWH)(8,760 H/yr)
= $329,133/yr

[6] (180 kW/54,200 kW) × 100 = 0.443%

Catalyst Replacement: The catalyst must be replaced every 5 years. This means, the catalysts may need to be replaced at 5th year and 10th year in a 10 year period. The present value for catalyst replacements over a period of 10 years is calculated as follows:

$$\text{Pn} = \text{Cost of Catalyst}\left(\frac{1}{(i+1)^n}\right)$$

Where:

Cost of Catalysts = $164,800
Interest Rate (i), assumed to be 10%.
n = lifetime of the equipment

When n= 5,

$$P_5 = \$164{,}800\left(\frac{1}{(0.1+1)^5}\right) = \$102{,}328$$

Similarly, when n = 10 in the above equation then

$P_{10}$ = $63,538

Equivalent Annual Cost of Catalysts replacements:

$$A = (P)\left[\frac{(i)(1+i)^n}{(1+i)^n - 1}\right]$$

Where:

A: Equivalent annual capital cost of the control equipment
P: Present value of the control equipment
I: Interest rate (District policy is to use 10%)
n: Equipment life (District policy is to use 10 years)

$$A = (174{,}851 + 108{,}569)\left[\frac{(0.1)(1+0.1)^{10}}{(1+0.1)^{10} - 1}\right] = \frac{\$26{,}994}{\text{yr}}$$

Total Direct Annual Cost (DAC) = $329,133/yr + $26,994/yr
= $356,127/yr

Indirect Annual Costs (IAC)

| | |
|---|---|
| Overhead (not included) | |
| Administrative (0.02 TCI) | = \$29,451 |
| Insurance (0.01 TCI) | = \$14,726 |
| Property Tax (0.01 TCI) | = \$14,726 |
| Total (IAC) | = \$58,903 |

Total Cost:

The total cost to purchase, install, maintain and operate the oxidation systems for three gas turbines would be:

Total = ATCI (\$/yr) + DAC (\$/yr) + IAC (\$/yr)
= \$239,654/yr + \$356,127 + \$58,903/yr
**= \$654,684/yr**

MCET:

Oxidation catalyst reduces CO emissions as well as VOC emissions. Thus, multi-pollutant cost effectiveness threshold (MCET) must be determined for comparison with the total cost of \$654,684/yr.

*VOC*

VOC emissions of 5[7] ppmv @ 15% $O_2$ is assumed to be the industry standard for the gas turbines. The emission reductions from the industry standard to the technologically feasible option of 0.6 ppmv @ 15% $O_2$ are determined in the following section.

VOC emissions using 2.0 ppmvd @ 15% $O_2$ are 10,601 lb/yr-unit during baseload period, and 730 lb/yr-unit during startup/shutdown periods. These emissions rates are taken from Section VII of this document.

Using this information, VOC concentration of 5 ppmvd @ 15% $O_2$ would be:

= (5 ppmvd/2 ppmvd)(10,601 lb-VOC/yr-unit)(3 units) + (730 lb-VOC/yr-unit)(3 units)
= 81,698 lb-VOC/yr

Similarly, VOC emissions using 1.3 ppmvd @ 15% $O_2$ would be:

= (1.3 ppmvd/2 ppmvd)(10,601 lb-VOC/yr-unit)(3 units) + (730 lb-VOC/yr-unit)(3 units)
= 22,862 lb-VOC/yr

[7] Referenced from the presentation of EmeraChem Power, June 26, 2008

VOC Reductions = 81,698 lb-VOC/yr – 22,862 lb-VOC/yr
= 58,836 lb-VOC/yr

*CO*

CO emissions of 25[4] ppmv @ 15% $O_2$ is assumed to be the industry standard for the gas turbines. Per TID's consultant, CO emissions are expected to be 1.5 ppmvd @ 15% $O_2$ with use of this oxidation catalyst.

CO emissions using 4.0 ppmvd @ 15% $O_2$ are 37,019 lb/yr-unit during baseload period, and 14,600 lb/yr-unit during startup/shutdown periods. These emissions rates are taken from Section VII of this document. Using this information, CO emissions of 25 ppmvd @ 15% $O_2$ would be:

= (25 ppmvd/4 ppmvd)(37,019 lb-CO/yr-unit)(3 units) + (14,600 lb-CO/yr-unit)(3 units)
= 737,906 lb-CO/yr

Similarly, CO emissions of 1.5 ppmvd @ 15% $O_2$ would be:

= (1.5 ppmvd/4 ppmvd)(37,019 lb-CO/yr-unit)(3 units) + (14,600 lb-CO/yr-unit)(3 units)
= 85,446 lb-CO/yr

CO Reductions = 737,906 lb-CO/yr – 85,446 lb-CO/yr
= 652,460 lb-CO/yr

*MCET*

Cost effectiveness threshold for VOC and CO are $17,500/ton and $300/ton respectively. These thresholds are used to determine the MCET for this project.

MCET = ($17,500/ton)(58,836 lb-VOC/yr)(ton/2,000 lb)
+ ($300/ton)(652,460 lb-CO/yr)(ton/2,000 lb)
**= $612,684**

The total cost to purchase, install, maintain and operate the oxidation systems for three gas turbines would be $654,684/yr, which is greater than the multi-pollutant cost effectiveness threshold of $612,684. Therefore, this option of reducing VOC emissions to 1.3 ppmvd @ 15% $O_2$, is not cost-effective and is removed from consideration at this time.

**Option 3: 2.0 ppmvd @ 15% $O_2$ based on a three-hour rolling average**

Cost analysis is not necessary, as this emission limit is achieved-in-practice.

**Step 5 - Select BACT**

BACT would be to achieve 2.0 ppmvd @ 15% $O_2$ on a 3-hour rolling average period.

TID has proposed to achieve VOC concentrations of 2.0 ppmvd @ 15% $O_2$ or less over a 3-hour rolling average period. Therefore, BACT requirements are satisfied.

## IV. $PM_{10}$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.7 lists the following emissions limits or control technologies:

Achieved-in-Practice

- Air inlet filter, lube oil vent coalescer and either PUC regulated natural gas, LPG, or non-PUC regulated gas with < 0.75 gr-S/100 dscf

Technologically Feasible

None

Alternate Basic Equipment

None

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

Air inlet filter, lube oil vent coalescer and either PUC regulated natural gas, LPG, or non-PUC regulated gas with < 0.75 gr-S/100 dscf

**Step 4 - Cost Effectiveness Analysis**

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The proposed CTGs will be equipped with an inlet air filter, lube oil vent coalescer and be operated on PUC regulated natural gas fuel. This is the only ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the gas turbine system is to use an air inlet filter, lube oil vent coalescer and PUC regulated natural gas fuel or equal.

The proposed turbines will be equipped with an air inlet filter, lube oil vent coalescer, and will be operated using PUC regulated natural gas fuel. Therefore, BACT requirements are satisfied.

## V. $SO_X$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.7 lists the following emissions limits or control technologies:

Achieved-in-Practice

PUC-regulated natural gas, LPG, or non-PUC-regulated gas with no more than 0.75 grains S/100 dscf

Technologically Feasible

None

Alternate Basic Equipment

None

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

**Step 4 - Cost Effectiveness Analysis**

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.
The applicant has proposed to use PUC-regulated natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the gas turbine system is to use PUC-regulated natural gas or PUC quality gas with 0.75 grains S/100 dscf.

The applicant has proposed to use PUC-regulated natural gas fuel. Therefore, the BACT requirements are satisfied.

# ATTACHMENT F
# HEALTH RISK ASSESSMENT AND AMBIENT AIR QUALITY ANALYSIS

# San Joaquin Valley Air Pollution Control District
# Risk Management Review

| | |
|---|---|
| To: | Jag Kahlon |
| From: | Matthew Cegielski – Technical Services |
| Date: | November 17, 2009 |
| Facility Name: | Turlock Irrigation District |
| Location: | 4500 Crows Landing Road Modesto, CA |
| Application #(s): | N-3299-4-0, 5-0, 6-0 |
| Project #: | N-1091384 |

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## A. RMR SUMMARY

| RMR Summary | | | | | |
|---|---|---|---|---|---|
| **Categories** | **CT #1 4-0** | **CT #2 5-0** | **CT #3 6-0** | **Project Totals** | **Facility Totals** |
| **Prioritization Score** | **1.25** | **1.25** | **1.25** | **3.8** | **3.8** |
| **Acute Hazard Index** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **Chronic Hazard Index** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **Maximum Individual Cancer Risk ($10^{-6}$)** | **0.0** | **0.0** | **0.0** | **0.0** | **0.1** |
| **T-BACT Required?** | **No** | **No** | **No** | | |
| **Special Permit Conditions?** | **Yes** | **Yes** | **Yes** | | |

**Proposed Permit Conditions**

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

Units 4-0, 5-0, 6-0

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

## B. RMR REPORT

### I. Project Description

Technical Services received a request on November 17, 2009 to perform a Risk Management Review for a proposed installation of three 54.2 MW (each) simple cycle gas turbines. This was a revision of a previous proposed project on June 10th. Modification involved an increase in the maximum hourly heat input from 523 to 554.9 MMBtu/hr and the consideration of maximum hourly NOx, SOx and CO from Startup/Shutdown. Annual heat input did not change.

## II. Analysis

Toxic emissions for this proposed unit were calculated using Ventura County's emission factors for natural gas external combustion. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 5 years (2004 to 2008) from Modesto to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| Analysis Parameters<br>Combustion Turbines Unit 4-0, 5-0, 6-0 | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 24.4 | **Closest Receptor (m)** | 183 |
| **Stack Diameter. (m)** | 3.66 | **Type of Receptor** | Business |
| **Stack Exit Velocity (m/s)** | 29.73 | **Max Hours per Year** | 8760 |
| **Stack Exit Temp. (°K)** | 727.4 | **Fuel Type** | NG |
| **Burner Rating (MMBtu/hr)** | 554.9 | | |

Technical Services performed AAQA modeling for criteria pollutants CO, NOx, SOx and $PM_{10}$. Emissions are listed in the table below, for concentrations refer to the AAQA modeling profile.

| lbs/hr | Units 4,5,6 (Each) CTs Daily Average | Units 4,5,6 (Each) CTs 1 hr Max | lbs/yr | Units 4,5,6 (Each) CTs |
|---|---|---|---|---|
| NOx | | 25 | NOx | 47,187 |
| CO | 7.56 | 40 | CO | 51,619 |
| PM10 | 2.5 | | PM10 | 21,901 |
| SOx | 1.48 | 1.56 | SOx | 12,912 |

**Criteria Pollutant Modeling Results***

| | 1 Hour | 3 Hours | 8 Hours. | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_x$ | Pass | X | X | X | Pass |
| $SO_x$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[1] | Pass[1] |

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

**$PM_{10}$ Pollutant Modeling Results***
Values are in μg/m$^3$

| Category | 24 Hours | Annual |
|---|---|---|
| Proposed | 0.61 | 0.175 |
| Significance Level | 5.0 | 1.0 |
| Result | Pass | Pass |

## III. Conclusion

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

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

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

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

**Attachments:**

A. HARP output files
B. Prioritization score with toxic emissions summary, AAQA
C. RMR request from the project engineer

FILE: c:\HARP\projects\demo\Rep_PMI.txt

EXCEPTION REPORT
(there have been no changes or exceptions)

RECEPTORS WITH HIGHEST CANCER RISK

| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 809 | GRID | 3.05E-07 | 2.19E-03 | 4.35E-03 | 678284 | 4160232 | 11 |
| 808 | GRID | 3.02E-07 | 2.16E-03 | 4.12E-03 | 678268 | 4160190 | 11 |
| 800 | GRID | 2.99E-07 | 2.14E-03 | 4.40E-03 | 678216 | 4160270 | 11 |
| 669 | GRID | 2.98E-07 | 2.14E-03 | 3.76E-03 | 678332 | 4160153 | 11 |
| 668 | GRID | 2.96E-07 | 2.13E-03 | 3.78E-03 | 678309 | 4160143 | 11 |
| 670 | GRID | 2.96E-07 | 2.12E-03 | 3.76E-03 | 678355 | 4160162 | 11 |
| 799 | GRID | 2.95E-07 | 2.12E-03 | 4.35E-03 | 678208 | 4160248 | 11 |
| 643 | GRID | 2.92E-07 | 2.10E-03 | 4.68E-03 | 678217 | 4160304 | 11 |
| 810 | GRID | 2.92E-07 | 2.09E-03 | 4.71E-03 | 678300 | 4160274 | 11 |
| 667 | GRID | 2.91E-07 | 2.09E-03 | 3.83E-03 | 678286 | 4160134 | 11 |
| 642 | GRID | 2.90E-07 | 2.08E-03 | 4.37E-03 | 678194 | 4160295 | 11 |
| 671 | GRID | 2.90E-07 | 2.08E-03 | 3.78E-03 | 678379 | 4160174 | 11 |
| 798 | GRID | 2.88E-07 | 2.06E-03 | 4.33E-03 | 678200 | 4160227 | 11 |
| 807 | GRID | 2.86E-07 | 2.05E-03 | 4.00E-03 | 678252 | 4160148 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.97E-03 | 678237 | 4160317 | 11 |
| 672 | GRID | 2.84E-07 | 2.04E-03 | 3.88E-03 | 678388 | 4160197 | 11 |
| 666 | GRID | 2.81E-07 | 2.02E-03 | 3.86E-03 | 678264 | 4160124 | 11 |
| 641 | GRID | 2.81E-07 | 2.01E-03 | 4.16E-03 | 678171 | 4160285 | 11 |
| 811 | GRID | 2.79E-07 | 2.00E-03 | 4.79E-03 | 678308 | 4160295 | 11 |
| 819 | GRID | 2.77E-07 | 1.99E-03 | 3.23E-03 | 678429 | 4160093 | 11 |

RECEPTORS WITH HIGHEST CHRONIC HI

| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 809 | GRID | 3.05E-07 | 2.19E-03 | 4.35E-03 | 678284 | 4160232 | 11 |
| 808 | GRID | 3.02E-07 | 2.16E-03 | 4.12E-03 | 678268 | 4160190 | 11 |
| 800 | GRID | 2.99E-07 | 2.14E-03 | 4.40E-03 | 678216 | 4160270 | 11 |
| 669 | GRID | 2.98E-07 | 2.14E-03 | 3.76E-03 | 678332 | 4160153 | 11 |
| 668 | GRID | 2.96E-07 | 2.13E-03 | 3.78E-03 | 678309 | 4160143 | 11 |
| 799 | GRID | 2.95E-07 | 2.12E-03 | 4.35E-03 | 678208 | 4160248 | 11 |
| 670 | GRID | 2.96E-07 | 2.12E-03 | 3.76E-03 | 678355 | 4160162 | 11 |
| 643 | GRID | 2.92E-07 | 2.10E-03 | 4.68E-03 | 678217 | 4160304 | 11 |
| 667 | GRID | 2.91E-07 | 2.09E-03 | 3.83E-03 | 678286 | 4160134 | 11 |
| 810 | GRID | 2.92E-07 | 2.09E-03 | 4.71E-03 | 678300 | 4160274 | 11 |
| 642 | GRID | 2.90E-07 | 2.08E-03 | 4.37E-03 | 678194 | 4160295 | 11 |
| 671 | GRID | 2.90E-07 | 2.08E-03 | 3.78E-03 | 678379 | 4160174 | 11 |
| 798 | GRID | 2.88E-07 | 2.06E-03 | 4.33E-03 | 678200 | 4160227 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.97E-03 | 678237 | 4160317 | 11 |
| 807 | GRID | 2.86E-07 | 2.05E-03 | 4.00E-03 | 678252 | 4160148 | 11 |
| 672 | GRID | 2.84E-07 | 2.04E-03 | 3.88E-03 | 678388 | 4160197 | 11 |
| 666 | GRID | 2.81E-07 | 2.02E-03 | 3.86E-03 | 678264 | 4160124 | 11 |
| 641 | GRID | 2.81E-07 | 2.01E-03 | 4.16E-03 | 678171 | 4160285 | 11 |
| 811 | GRID | 2.79E-07 | 2.00E-03 | 4.79E-03 | 678308 | 4160295 | 11 |
| 819 | GRID | 2.77E-07 | 1.99E-03 | 3.23E-03 | 678429 | 4160093 | 11 |

RECEPTORS WITH HIGHEST ACUTE HI

| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 648 | GRID | 1.90E-07 | 1.37E-03 | 5.43E-03 | 678274 | 4160409 | 11 |
| 647 | GRID | 2.21E-07 | 1.58E-03 | 5.42E-03 | 678265 | 4160386 | 11 |
| 751 | GRID | 1.79E-07 | 1.28E-03 | 5.41E-03 | 678255 | 4160424 | 11 |
| 646 | GRID | 2.48E-07 | 1.78E-03 | 5.30E-03 | 678256 | 4160363 | 11 |
| 645 | GRID | 2.70E-07 | 1.93E-03 | 5.11E-03 | 678247 | 4160340 | 11 |
| 649 | GRID | 1.60E-07 | 1.15E-03 | 5.10E-03 | 678283 | 4160432 | 11 |
| 757 | GRID | 1.97E-07 | 1.41E-03 | 5.03E-03 | 678340 | 4160380 | 11 |
| 750 | GRID | 1.50E-07 | 1.07E-03 | 5.02E-03 | 678254 | 4160448 | 11 |
| 812 | GRID | 2.44E-07 | 1.75E-03 | 4.99E-03 | 678324 | 4160337 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.97E-03 | 678237 | 4160317 | 11 |
| 456 | GRID | 3.61E-08 | 2.59E-04 | 4.91E-03 | 677709 | 4160860 | 11 |
| 455 | GRID | 3.48E-08 | 2.50E-04 | 4.91E-03 | 677746 | 4160876 | 11 |
| 628 | GRID | 1.77E-07 | 1.27E-03 | 4.90E-03 | 678202 | 4160435 | 11 |
| 454 | GRID | 3.15E-08 | 2.26E-04 | 4.88E-03 | 677783 | 4160892 | 11 |
| 627 | GRID | 2.08E-07 | 1.49E-03 | 4.88E-03 | 678193 | 4160412 | 11 |
| 756 | GRID | 1.72E-07 | 1.23E-03 | 4.87E-03 | 678339 | 4160403 | 11 |
| 340 | GRID | 3.43E-08 | 2.46E-04 | 4.85E-03 | 677747 | 4160837 | 11 |
| 353 | GRID | 3.39E-08 | 2.43E-04 | 4.83E-03 | 677747 | 4160921 | 11 |
| 341 | GRID | 3.45E-08 | 2.47E-04 | 4.83E-03 | 677718 | 4160825 | 11 |
| 354 | GRID | 3.61E-08 | 2.59E-04 | 4.81E-03 | 677717 | 4160908 | 11 |

RISK - File: C:\HARP\PROJECTS\My Projec

Files Step-Through Analysis Export/Import Sort

Sources | Receptors | Emissions | X/Q | GLC | Risk

| Receptor | Type | Cancer Risk | Chronic HI | Acute Simple HI | Acute Ma HI |
|---|---|---|---|---|---|
| 1 | GRID | 8.88E-09 | 6.37E-05 | 1.31E-03 | -1 |
| 2 | GRID | 9.74E-09 | 6.99E-05 | 1.70E-03 | -1 |
| 3 | GRID | 1.49E-08 | 1.07E-04 | 1.10E-03 | -1 |
| 4 | GRID | 1.32E-08 | 9.50E-05 | 1.44E-03 | -1 |
| 5 | GRID | 8.99E-09 | 6.45E-05 | 1.51E-03 | -1 |
| 6 | GRID | 6.22E-09 | 4.46E-05 | 8.29E-04 | -1 |
| 7 | GRID | 1.20E-08 | 8.62E-05 | 1.67E-03 | -1 |
| 8 | GRID | 5.47E-09 | 3.93E-05 | 6.66E-04 | -1 |
| 9 | GRID | 1.23E-08 | 8.82E-05 | 1.89E-03 | -1 |
| 10 | GRID | 1.59E-08 | 1.14E-04 | 2.12E-03 | -1 |
| 11 | GRID | 9.86E-09 | 7.07E-05 | 1.58E-03 | -1 |
| 12 | GRID | 8.75E-09 | 6.28E-05 | 1.49E-03 | -1 |
| 13 | GRID | 7.77E-09 | 5.58E-05 | 1.42E-03 | -1 |
| 14 | GRID | 6.97E-09 | 5.00E-05 | 1.29E-03 | -1 |
| 15 | GRID | 6.40E-09 | 4.59E-05 | 1.25E-03 | -1 |
| 16 | GRID | 6.15E-09 | 4.41E-05 | 1.21E-03 | -1 |
| 17 | GRID | 1.03E-08 | 7.42E-05 | 1.53E-03 | -1 |
| 18 | GRID | 1.20E-08 | 8.59E-05 | 1.77E-03 | -1 |
| 19 | GRID | 1.45E-08 | 1.04E-04 | 2.02E-03 | -1 |
| 20 | GRID | 1.92E-08 | 1.37E-04 | 2.08E-03 | -1 |
| 21 | GRID | 9.14E-09 | 6.55E-05 | 1.50E-03 | -1 |
| 22 | GRID | 8.62E-09 | 6.18E-05 | 1.46E-03 | -1 |
| 23 | GRID | 8.21E-09 | 5.89E-05 | 1.39E-03 | -1 |
| 24 | GRID | 7.92E-09 | 5.68E-05 | 1.38E-03 | -1 |
| 25 | GRID | 7.81E-09 | 5.60E-05 | 1.46E-03 | -1 |
| 26 | GRID | 7.96E-09 | 5.71E-05 | 1.55E-03 | -1 |
| 27 | GRID | 9.23E-09 | 6.62E-05 | 1.37E-03 | -1 |

# PRIORITIZATION
# FOR

# TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

DEVICE NUMBER 4
DEVICE NAME 54.2 MW NG CTG

| | | | | Emissions and Potency Method | | | Despersion Adjustment Method | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Prioritization Scores | | | Prioritization Scores | | |
| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.11E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 5.22E-02 | 1.10E+00 | 2.05E-01 | 3.56E-01 | 5.53E-01 | 1.05E-01 | 1.81E-01 |
| 71432 | Benzene | 5.18E+01 | 6.27E-03 | 6.38E-01 | 3.70E-03 | 1.81E-03 | 3.22E-01 | 1.89E-03 | 9.22E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 2.05E-02 | 1.94E-01 | 5.20E-03 | 1.64E-02 | 9.80E-02 | 2.65E-03 | 8.35E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.44E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 7.32E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.99E-03 | | 5.06E-01 | 7.49E-01 | | 2.58E-01 | 3.82E-01 |
| 108883 | Toluene | 3.33E+02 | 4.03E-02 | | 4.76E-03 | 4.08E-04 | | 2.43E-03 | 2.08E-04 |
| 110543 | Hexane | 8.02E+03 | 9.71E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.84E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.60E-02 | | 8.12E-04 | 2.73E-04 | | 4.14E-04 | 1.39E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.44E+00 | | 1.32E+00 | 8.72E-01 | | 6.74E-01 | 4.45E-01 |
| | | TOTALS FOR DEVICE 4 | | 2.48E+00 | 2.06E+00 | 2.00E+00 | 1.25E+00 | 1.05E+00 | 1.02E+00 |

DEVICE NUMBER 5
DEVICE NAME 54.2 MW NG CTG

| | | | | Emissions and Potency Method | | | Despersion Adjustment Method | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Prioritization Scores | | | Prioritization Scores | | |
| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.11E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 5.22E-02 | 1.10E+00 | 2.05E-01 | 3.56E-01 | 5.53E-01 | 1.05E-01 | 1.81E-01 |
| 71432 | Benzene | 5.18E+01 | 6.27E-03 | 6.38E-01 | 3.70E-03 | 1.81E-03 | 3.22E-01 | 1.89E-03 | 9.22E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 2.05E-02 | 1.94E-01 | 5.20E-03 | 1.64E-02 | 9.80E-02 | 2.65E-03 | 8.35E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.44E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 7.32E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.99E-03 | | 5.06E-01 | 7.49E-01 | | 2.58E-01 | 3.82E-01 |

# PRIORITIZATION
# FOR

# TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 108883 | Toluene | 3.33E+02 | 4.03E-02 | | 4.76E-03 | 4.08E-04 | | 2.43E-03 | 2.08E-04 |
| 110543 | Hexane | 8.02E+03 | 9.71E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.84E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.60E-02 | | 8.12E-04 | 2.73E-04 | | 4.14E-04 | 1.39E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.44E+00 | | 1.32E+00 | 8.72E-01 | | 6.74E-01 | 4.45E-01 |
| | | | TOTALS FOR DEVICE 5 | 2.48E+00 | 2.06E+00 | 2.00E+00 | 1.25E+00 | 1.05E+00 | 1.02E+00 |

DEVICE NUMBER 6
DEVICE NAME 54.2 MW NG CTG

| | | | | Emissions and Potency Method | | | Despersion Adjustment Method | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Prioritization Scores | | | Prioritization Scores | | |
| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.11E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 5.22E-02 | 1.10E+00 | 2.05E-01 | 3.56E-01 | 5.53E-01 | 1.05E-01 | 1.81E-01 |
| 71432 | Benzene | 5.18E+01 | 6.27E-03 | 6.38E-01 | 3.70E-03 | 1.81E-03 | 3.22E-01 | 1.89E-03 | 9.22E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 2.05E-02 | 1.94E-01 | 5.20E-03 | 1.64E-02 | 9.80E-02 | 2.65E-03 | 8.35E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.44E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 7.32E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.99E-03 | | 5.06E-01 | 7.49E-01 | | 2.58E-01 | 3.82E-01 |
| 108883 | Toluene | 3.33E+02 | 4.03E-02 | | 4.76E-03 | 4.08E-04 | | 2.43E-03 | 2.08E-04 |
| 110543 | Hexane | 8.02E+03 | 9.71E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.84E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.60E-02 | | 8.12E-04 | 2.73E-04 | | 4.14E-04 | 1.39E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.44E+00 | | 1.32E+00 | 8.72E-01 | | 6.74E-01 | 4.45E-01 |
| | | | TOTALS FOR DEVICE 6 | 2.48E+00 | 2.06E+00 | 2.00E+00 | 1.25E+00 | 1.05E+00 | 1.02E+00 |

# PRIORITIZATION
# FOR

# TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

## Emissions and Potency Method

**Prioritization Scores**

| Cancer | CHRONIC | ACUTE |
|---|---|---|
| 7.43E+00 | 6.18E+00 | 5.99E+00 |

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor ( Cancer = 1700, Acute = 1500, Chronic = 150)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance

| | RP |
|---|---|
| 0m < R < 100m | 1.0 |
| 100m < R < 250m | 0.25 |
| 250m < R < 500m | 0.04 |
| 500m < R < 1000m | 0.011 |
| 1000m < R < 1500m | 0.003 |
| 1500m < R < 2000m | 0.002 |
| R > 2000m | 0.001 |

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * 1700

Acute Score:
TS(t) = [ EHR(t) / AREL(t) ] * RP * 1500

Chronic Score:
TS(t) = { ( [ EYR(t) / Hours Of Operation ] / CREL(t) ) * RP * 150 }

## Dispersion Adjustment Method

**Prioritization Scores**

| Cancer | CHRONIC | ACUTE |
|---|---|---|
| 3.74E+00 | 3.15E+00 | 3.05E+00 |

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor ( Cancer = 28, Acute = 25, Chronic = 2.5)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
SHA = Stack Height Adjustment ( < 20m = 60, < 45m = 9, >= 45m = 1)
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance
H = Stack Height

| For Stack - 0m <= H < 20m | RP | For Stack - 20m <= H < 45m | RP | For Stack - >= H < 45m | RP |
|---|---|---|---|---|---|
| 0m < R < 100m | 1.0 | 0m < R < 100m | 1.0 | 0m < R < 100m | 1.0 |
| 100m < R < 250m | 0.25 | 100m < R < 250m | 0.85 | 100m < R < 250m | 1.0 |
| 250m < R < 500m | 0.04 | 250m < R < 500m | 0.22 | 250m < R < 500m | 0.90 |
| 500m < R < 1000m | 0.011 | 500m < R < 1000m | 0.064 | 500m < R < 1000m | 0.40 |
| 1000m < R < 1500m | 0.003 | 1000m < R < 1500m | 0.018 | 1000m < R < 1500m | 0.13 |
| 1500m < R < 2000m | 0.002 | 1500m < R < 2000m | 0.009 | 1500m < R < 2000m | 0.066 |
| R > 2000m | 0.001 | R > 2000m | 0.006 | R > 2000m | 0.042 |

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * SHA * 28

Acute Score:
TS(t) = [ EHR(t) / AREL(t) ] * RP * SHA * 25

Chronic Score:
TS(t) = { ( [ EYR(t) / Hours Of Operation ] / CREL(t) ) * RP * SHA * 2.5 }

# AAQA for Turlock Irrigation District Almond PP ( N3299 )
## All Values are in ug/m^3

| | NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|---|
| STCK1 | 6.145E+00 | 5.321E-02 | 1.311E+01 | 1.036E+00 | 5.113E-01 | 3.342E-01 | 1.164E-01 | 1.949E-02 | 1.966E-01 | 3.293E-02 |
| STCK2 | 6.651E+00 | 5.412E-02 | 1.419E+01 | 1.046E+00 | 5.534E-01 | 3.284E-01 | 1.213E-01 | 1.983E-02 | 2.049E-01 | 3.349E-02 |
| STCK3 | 6.366E+00 | 5.401E-02 | 1.358E+01 | 1.034E+00 | 5.297E-01 | 3.028E-01 | 1.217E-01 | 1.978E-02 | 2.055E-01 | 3.342E-02 |
| Background | 1.377E+02 | 2.678E+01 | 8.039E+03 | 4.311E+03 | 1.300E-01 | 7.500E-02 | 3.100E-02 | 7.000E-03 | 9.700E+01 | 3.500E+01 |
| **Facility Totals** | 1.569E+02 | 2.694E+01 | 8.079E+03 | 4.314E+03 | 1.724E+00 | 1.040E+00 | 3.903E-01 | 6.610E-02 | 9.761E+01 | 3.510E+01 |
| **AAQS** | 338 | 56 | 23000 | 10000 | 655 | 1300 | 105 | 80 | 50 | 30 |
| | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Fail** | **Fail** |
| | | | | | | | | 0.06×1.75<br>0.1 | 0.61 | 0.1<1.75<br>0.175 |

## EPA's Significatance Level (ug/m^3)

| NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|
| 0.0 | 1.0 | 2000.0 | 500.0 | 0.0 | 25.0 | 5.0 | 1.0 | 5.0 | 1.0 |

# *AAQA Emission (g/sec)*

| *Device* | NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|---|
| STCK1 | 3.15E+00 | 6.79E-01 | 5.04E+00 | 9.52E-01 | 1.97E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |
| STCK2 | 3.15E+00 | 6.79E-01 | 5.04E+00 | 9.52E-01 | 1.97E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |
| STCK3 | 3.15E+00 | 6.79E-01 | 5.04E+00 | 9.52E-01 | 1.97E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |

**Ester Davila**

---

**From:** Jag Kahlon

**Sent:** Tuesday, November 17, 2009 9:47 AM

**To:** Ester Davila

**Subject:** TID's Project, N1091384

**Importance:** High

**Attachments:** RMR Analysis Report.doc; N3299, 1091384_RMR (Revised).doc

Ester,

In June, 2009, we performed the RMR and AAQA (attached) for Turlock Irrigation District's power plant project, in which, they are proposing to install three identical 54.2 MW (ISO rating), natural gas-fired, simple-cycle, gas turbines each equipped with its own SCR and oxidation catalyst system.

We have used a heat input rate of 523 MMBtu/hr for each gas turbine. Recently, the project consultant informed that they may have a heat input rate of 554.9 MMBtu/hr should the ambient temperature reaches 30°F. So, please re-run the RMR using the new hourly heat input rate. We may be able to use 4,581,480 MMBtu/yr-turbine (523 MMBtu/hr x 8,760 hr/yr) for determining chronic risks.

Regarding AAQA, it looks that we have used 6.43 lb-$NO_x$/hr, 47,187 lb-$NO_x$/yr; 7.56 lb-CO/hr, 54,619 lb-CO/yr; 2.5 lb-$PM_{10}$/hr, 21,901 lb-$PM_{10}$/yr; and 1.48 lb-$SO_x$/hr, 12,912 lb-$SO_x$/yr. I don't know how the hourly $NO_x$ and CO emissions were determined. Please use worst-case potential emissions from the attached revised RMR to conduct the AAQA.

Matthew Cegielski worked on the project, and I have discussion with him on this issue.

Thanks,

Jagmeet Kahlon
Air Quality Engineer
San Joaquin Valley Air Pollution Control District
4800 Enterprise Way | Modesto, CA | 95356-8718
(209) 557-6452 | Fax (209) 557-6475

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# ENGINEERING HRA
# REVIEW & MODELING REQUEST
# (Revised)

| | | | |
|---|---|---|---|
| Facility Name: | Turlock Irrigation District (TID) | Process Engineer: | Jag Kahlon |
| Mailing Address: | P.O. Box 949<br>Turlock, CA 95381 | Life Of Project: | |
| Location: | 4500 Crows Landing Rd<br>Modesto, CA | Processing Staff: | |
| Contact Name: | Nancy Matthews, Consultant | Start Date: | |
| Telephone: | (916) 444-6666 | Completed Date: | |
| Application #: | N-3299-4, 5-0, 6-0 | Reviewed By: | |
| Project #: | N-1091384 | Date: | |

FAX OR MAIL TO TECHNICAL SERVICES SUPERVISOR

| HRA Information Checklist | Yes | No |
|---|---|---|
| Is all of the following information provided (as applicable)?<br>☒ Receptor distances<br>☒ Stack velocity<br>☒ Stack height<br>☒ Stack temperature<br>☒ Emission/Usage Rates (hour/annual)<br>☒ Hours of Operation<br>☐ MSDS<br>☐ Other (for area sources) | ☒ | ☐ Incomplete (Otherwise, explain under Comments). |
| Supplemental Application Form attached (as applicable)? | ☐ Only HRA cover page is required. | ☒ Submit complete HRA Request Form. |
| Is it obvious that notification is required (NSR, COC, or school)?<br>☒ NSR (Public Notice): *Distances to the fence line in all four directions are required*<br>☒ COC (EPA Notice)<br>☐ School Notice | ☒ | ☐ |
| Has the applicant requested reimbursable overtime processing? | ☐<br>• Get approval from your supervisor.<br>• Send HRA request to Tech Services before deeming complete. | ☒ |
| Supervisor's signature for expedited processing: | | |
| Comments and References: | | |

# SCREENING HRA REQUEST

I. Project Description:

Turlock Irrigation District (TID) is requesting Authority to Construct (ATC) permits for the installation of three 54.2 MW (each), nominal ISO rating, natural gas-fired, simple-cycle, peaking electric generation facility that will consist of General Electric's (GE) natural gas-fired aero derivative LM 6000 PG SPRINT (SPRay INTercoling water injection for increased power output) Combustion Turbine Generators (CTG). Each CTG is equipped with GE's state-of-the art single annular combustors with water injection rated at a combined heat input rate of 523 MMBtu/hr (ISO rating). Exhaust from each CTG will be vented through a Selective Catalytic Reduction (SCR) system for nitrogen oxide (NOx) emissions control, and through an oxidation catalyst to convert carbon monoxide (CO) into carbon dioxide ($CO_2$) gas.

II Receptor Location(s):

| Receptor Description (Units) | Distance From Source (Units) |
|---|---|
| Residence | 1,750 feet - NE |
| Business | 600 feet - W |

III. Process Rate Or Substances To Be Modeled:

Emissions from **each CTG** are as follows:

| **Potential $NO_X$ Emissions** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 25.00 | 50.0 | 2,250 | 2,275 | 2,300 | 2,300 | 9,125 |
| Turbine, base | 4.74 | -- | 9,385 | 9,489 | 9,594 | 9,594 | 38,062 |
| Turbine, peak | 5.02 | 110.4 | -- | -- | -- | -- | -- |
| Total: | **160.4** | 11,635 | 11,764 | 11,894 | 11,894 | **47,187** | |
| Daily (without startup/shutdown)[1]: | **120.5** | -- | -- | -- | -- | -- | |

1 hr
25
3.15
0.679

| **Potential CO Emissions** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 40.00 | 80.0 | 3,600 | 3,640 | 3,680 | 3,680 | 14,600 |
| Turbine, base | 4.61 | -- | 9,128 | 9,229 | 9,331 | 9,331 | 37,019 |
| Turbine, peak | 4.89 | 107.6 | -- | -- | -- | -- | -- |
| Total: | **187.6** | 12,728 | 12,869 | 13,011 | 13,011 | **51,619** | |
| Daily (without startup/shutdown)[1]: | **117.4** | -- | -- | -- | -- | -- | |

1 hr
40
5.04
8 hr
7.56
0.952

| **Potential VOC Emissions** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.00 | 4.0 | 180 | 182 | 184 | 184 | 730 |
| Turbine, base | 1.32 | -- | 2,614 | 2,643 | 2,672 | 2,672 | 10,601 |
| Turbine, peak | 1.40 | 30.8 | | | | | |
| Total: | **34.8** | 2,794 | 2,825 | 2,856 | 2,856 | **11,331** | |
| Daily (without startup/shutdown)[1]: | **33.6** | -- | -- | -- | -- | -- | |

| Potential $NH_3$ Emissions | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 7.44 | 14.9 | 670 | 677 | 684 | 684 | 2,715 |
| Turbine, base | 7.01 | -- | 14,511 | 14,672 | 14,833 | 14,833 | 58,849 |
| Turbine, peak | 7.44 | 163.7 | -- | -- | -- | -- | -- |
| Total: | | **178.6** | 15,181 | 15,349 | 15,517 | 15,517 | **61,564** |
| Daily (without startup/shutdown)[1]: | | **178.6** | -- | -- | -- | -- | -- |

| Potential $PM_{10}$ Emissions | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.50 | 5.0 | 225 | 228 | 230 | 230 | 913 |
| Turbine, base | 2.50 | -- | 5,175 | 5,233 | 5,290 | 5,290 | 20,988 |
| Turbine, peak | 2.50 | 55.0 | -- | -- | -- | -- | -- |
| Total: | | **60.0** | 5,400 | 5,461 | 5,520 | 5,520 | **21,901** |
| Daily (without startup/shutdown)[1]: | | **60.0** | -- | -- | -- | -- | -- |

2.5
0.315

| Potential $SO_x$ Emissions | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 1.56 | 3.1 | 140 | 142 | 144 | 144 | 570 |
| Turbine, base | 1.47 | -- | 3,043 | 3,077 | 3,111 | 3,111 | 12,342 |
| Turbine, peak | 1.56 | 34.3 | -- | -- | -- | -- | -- |
| Total: | | **37.4** | 3,183 | 3,219 | 3,255 | 3,255 | **12,912** |
| Daily (without startup/shutdown)[1]: | | **37.4** | -- | -- | -- | -- | -- |

1 hr
1.56
0.197
24
1.48
0.186

IV. Project Location (Select One): Urban (1) or Rural (2)
2. Rural - area of sparse population

V. Point Sources:

For **each CTG:**

| Stack Height (Units) | Inside Diameter (Units) | Gas Exit Velocity (Units) | Gas Exit Temperature (Units) |
|---|---|---|---|
| 80 feet | 144 inches | 661,894 | 850 F |

VI: Area Sources[1]:

Area Parameters:

| Release Height[2] (Units) | Length Of Side (Units) |
|---|---|
| | |

1. An area source is defined as in an area with four equal sides.
2. Release height is defined as the physical height of the source. For example, if a sump has a three meter brim surrounding it. The physical height of the sump is three meters. Height is measured from the ground to the top of the source.

# San Joaquin Valley Air Pollution Control District
# Risk Management Review

To: Jag Kahlon

From: Matthew Cegielski – Technical Services

Date: June 10, 2009

Facility Name: Turlock Irrigation District

Location: 4500 Crows Landing Road Modesto, CA

Application #(s): N-3299-4-0, 5-0, 6-0

Project #: N-1091384

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## A. RMR SUMMARY

| RMR Summary | | | | | |
|---|---|---|---|---|---|
| **Categories** | **CT #1 4-0** | **CT #2 5-0** | **CT #3 6-0** | **Project Totals** | **Facility Totals** |
| **Prioritization Score** | **1.25** | **1.25** | **1.25** | **3.8** | **3.8** |
| **Acute Hazard Index** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **Chronic Hazard Index** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **Maximum Individual Cancer Risk ($10^{-6}$)** | **0.0** | **0.0** | **0.0** | **0.0** | **0.1** |
| **T-BACT Required?** | **No** | **No** | **No** | | |
| **Special Permit Conditions?** | **No** | **No** | **No** | | |

**<u>Proposed Permit Conditions</u>**

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

<u>Units 4-0, 5-0, 6-0</u>

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

## B. RMR REPORT

### I. Project Description

Technical Services received a request on June 10, 2009 to perform a Risk Management Review for a proposed installation of three 54.2 MW (each) simple cycle gas turbines.

## II. Analysis

Toxic emissions for this proposed unit were calculated using Ventura County's emission factors for natural gas external combustion. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 5 years (2004 to 2008) from Modesto to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| **Analysis Parameters Combustion Turbines Unit 4-0, 5-0, 6-0** | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 24.4 | **Closest Receptor (m)** | 183 |
| **Stack Diameter. (m)** | 3.66 | **Type of Receptor** | Business |
| **Stack Exit Velocity (m/s)** | 29.73 | **Max Hours per Year** | 8760 |
| **Stack Exit Temp. (°K)** | 727.4 | **Fuel Type** | NG |
| **Burner Rating (MMBtu/hr)** | 523 | | |

Technical Services performed AAQA modeling for criteria pollutants CO, NOx, SOx and $PM_{10}$. Emissions are listed in the table below, for concentrations refer to the AAQA modeling profile.

| lbs/hr | Units 4,5,6 (Each) CTs | lbs/yr | Units 4,5,6 (Each) CTs |
|---|---|---|---|
| NOx | 6.43 | NOx | 47,187 |
| CO | 7.56 | CO | 51,619 |
| PM10 | 2.5 | PM10 | 21,901 |
| SOx | 1.48 | SOx | 12,912 |

**Criteria Pollutant Modeling Results***

| | 1 Hour | 3 Hours | 8 Hours. | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_x$ | Pass | X | X | X | Pass |
| $SO_x$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[1] | Pass[1] |

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

**$PM_{10}$ Pollutant Modeling Results***
Values are in μg/m$^3$

| Category | 24 Hours | Annual |
|---|---|---|
| Proposed | 1.05 | 0.175 |
| Significance Level | 5.0 | 1.0 |
| Result | Pass | Pass |

## III. Conclusion

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

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

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

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

**Attachments:**

A. HARP output files &AERMOD dispersion map
B. Prioritization score with toxic emissions summary, AAQA
C. RMR request from the project engineer

Files Step-Through Analysis Export/Import Sort M

Sources | Receptors | Emissions | X/Q | GLC | Risk

| Receptor | Type | Cancer Risk | Chronic HI | Acute Simple HI | Acute Max Hourly HI |
|---|---|---|---|---|---|
| 1 | GRID | 8.88E-09 | 6.37E-05 | 1.24E-03 | -1.00E+00 |
| 2 | GRID | 9.74E-09 | 6.99E-05 | 1.61E-03 | -1.00E+00 |
| 3 | GRID | 1.49E-08 | 1.07E-04 | 1.04E-03 | -1.00E+00 |
| 4 | GRID | 1.32E-08 | 9.50E-05 | 1.36E-03 | -1.00E+00 |
| 5 | GRID | 8.99E-09 | 6.45E-05 | 1.43E-03 | -1.00E+00 |
| 6 | GRID | 6.22E-09 | 4.46E-05 | 7.83E-04 | -1.00E+00 |
| 7 | GRID | 1.20E-08 | 8.62E-05 | 1.58E-03 | -1.00E+00 |
| 8 | GRID | 5.47E-09 | 3.93E-05 | 6.29E-04 | -1.00E+00 |
| 9 | GRID | 1.23E-08 | 8.82E-05 | 1.79E-03 | -1.00E+00 |
| 10 | GRID | 1.59E-08 | 1.14E-04 | 2.00E-03 | -1.00E+00 |
| 11 | GRID | 9.86E-09 | 7.07E-05 | 1.49E-03 | -1.00E+00 |
| 12 | GRID | 8.75E-09 | 6.28E-05 | 1.41E-03 | -1.00E+00 |
| 13 | GRID | 7.77E-09 | 5.58E-05 | 1.34E-03 | -1.00E+00 |
| 14 | GRID | 6.97E-09 | 5.00E-05 | 1.22E-03 | -1.00E+00 |
| 15 | GRID | 6.40E-09 | 4.59E-05 | 1.18E-03 | -1.00E+00 |
| 16 | GRID | 6.15E-09 | 4.41E-05 | 1.15E-03 | -1.00E+00 |
| 17 | GRID | 1.03E-08 | 7.42E-05 | 1.44E-03 | -1.00E+00 |
| 18 | GRID | 1.20E-08 | 8.59E-05 | 1.67E-03 | -1.00E+00 |
| 19 | GRID | 1.45E-08 | 1.04E-04 | 1.91E-03 | -1.00E+00 |
| 20 | GRID | 1.92E-08 | 1.37E-04 | 1.97E-03 | -1.00E+00 |
| 21 | GRID | 9.14E-09 | 6.55E-05 | 1.41E-03 | -1.00E+00 |
| 22 | GRID | 8.62E-09 | 6.18E-05 | 1.38E-03 | -1.00E+00 |
| 23 | GRID | 8.21E-09 | 5.89E-05 | 1.31E-03 | -1.00E+00 |
| 24 | GRID | 7.92E-09 | 5.68E-05 | 1.30E-03 | -1.00E+00 |
| 25 | GRID | 7.81E-09 | 5.60E-05 | 1.38E-03 | -1.00E+00 |
| 26 | GRID | 7.96E-09 | 5.71E-05 | 1.46E-03 | -1.00E+00 |
| 27 | GRID | 9.23E-09 | 6.62E-05 | 1.29E-03 | -1.00E+00 |
| 28 | GRID | 9.55E-09 | 6.85E-05 | 1.30E-03 | -1.00E+00 |
| 29 | GRID | 9.95E-09 | 7.14E-05 | 1.34E-03 | -1.00E+00 |
| 30 | GRID | 1.04E-08 | 7.50E-05 | 1.39E-03 | -1.00E+00 |
| 31 | GRID | 1.11E-08 | 7.94E-05 | 1.46E-03 | -1.00E+00 |
| 32 | GRID | 1.30E-08 | 9.29E-05 | 1.64E-03 | -1.00E+00 |
| 33 | GRID | 1.45E-08 | 1.04E-04 | 1.74E-03 | -1.00E+00 |
| 34 | GRID | 1.65E-08 | 1.18E-04 | 1.80E-03 | -1.00E+00 |
| 35 | GRID | 1.91E-08 | 1.37E-04 | 1.85E-03 | -1.00E+00 |
| 36 | GRID | 2.25E-08 | 1.62E-04 | 1.90E-03 | -1.00E+00 |
| 37 | GRID | 9.00E-09 | 6.46E-05 | 1.24E-03 | -1.00E+00 |
| 38 | GRID | 8.90E-09 | 6.38E-05 | 1.19E-03 | -1.00E+00 |
| 39 | GRID | 8.85E-09 | 6.35E-05 | 1.21E-03 | -1.00E+00 |
| 40 | GRID | 8.86E-09 | 6.35E-05 | 1.31E-03 | -1.00E+00 |
| 41 | GRID | 8.99E-09 | 6.45E-05 | 1.45E-03 | -1.00E+00 |

Done. Report written to c:\HARP\projects\demo\TIDPP_Rep_Ac

EXCEPTION REPORT
(there have been no changes or exceptions)

RECEPTORS WITH HIGHEST CANCER RISK

| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 809 | GRID | 3.05E-07 | 2.19E-03 | 4.10E-03 | 678284 | 4160232 | 11 |
| 808 | GRID | 3.02E-07 | 2.16E-03 | 3.89E-03 | 678268 | 4160190 | 11 |
| 800 | GRID | 2.99E-07 | 2.14E-03 | 4.15E-03 | 678216 | 4160270 | 11 |
| 669 | GRID | 2.98E-07 | 2.14E-03 | 3.55E-03 | 678332 | 4160153 | 11 |
| 668 | GRID | 2.96E-07 | 2.13E-03 | 3.57E-03 | 678309 | 4160143 | 11 |
| 670 | GRID | 2.96E-07 | 2.12E-03 | 3.55E-03 | 678355 | 4160162 | 11 |
| 799 | GRID | 2.95E-07 | 2.12E-03 | 4.11E-03 | 678208 | 4160248 | 11 |
| 643 | GRID | 2.92E-07 | 2.10E-03 | 4.42E-03 | 678217 | 4160304 | 11 |
| 810 | GRID | 2.92E-07 | 2.09E-03 | 4.45E-03 | 678300 | 4160274 | 11 |
| 667 | GRID | 2.91E-07 | 2.09E-03 | 3.62E-03 | 678286 | 4160134 | 11 |
| 642 | GRID | 2.90E-07 | 2.08E-03 | 4.13E-03 | 678194 | 4160295 | 11 |
| 671 | GRID | 2.90E-07 | 2.08E-03 | 3.57E-03 | 678379 | 4160174 | 11 |
| 798 | GRID | 2.88E-07 | 2.06E-03 | 4.09E-03 | 678200 | 4160227 | 11 |
| 807 | GRID | 2.86E-07 | 2.05E-03 | 3.78E-03 | 678252 | 4160148 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.70E-03 | 678237 | 4160317 | 11 |
| 672 | GRID | 2.84E-07 | 2.04E-03 | 3.66E-03 | 678388 | 4160197 | 11 |
| 666 | GRID | 2.81E-07 | 2.02E-03 | 3.64E-03 | 678264 | 4160124 | 11 |
| 641 | GRID | 2.81E-07 | 2.01E-03 | 3.93E-03 | 678171 | 4160285 | 11 |
| 811 | GRID | 2.79E-07 | 2.00E-03 | 4.52E-03 | 678308 | 4160295 | 11 |
| 819 | GRID | 2.77E-07 | 1.99E-03 | 3.05E-03 | 678429 | 4160093 | 11 |

RECEPTORS WITH HIGHEST CHRONIC HI

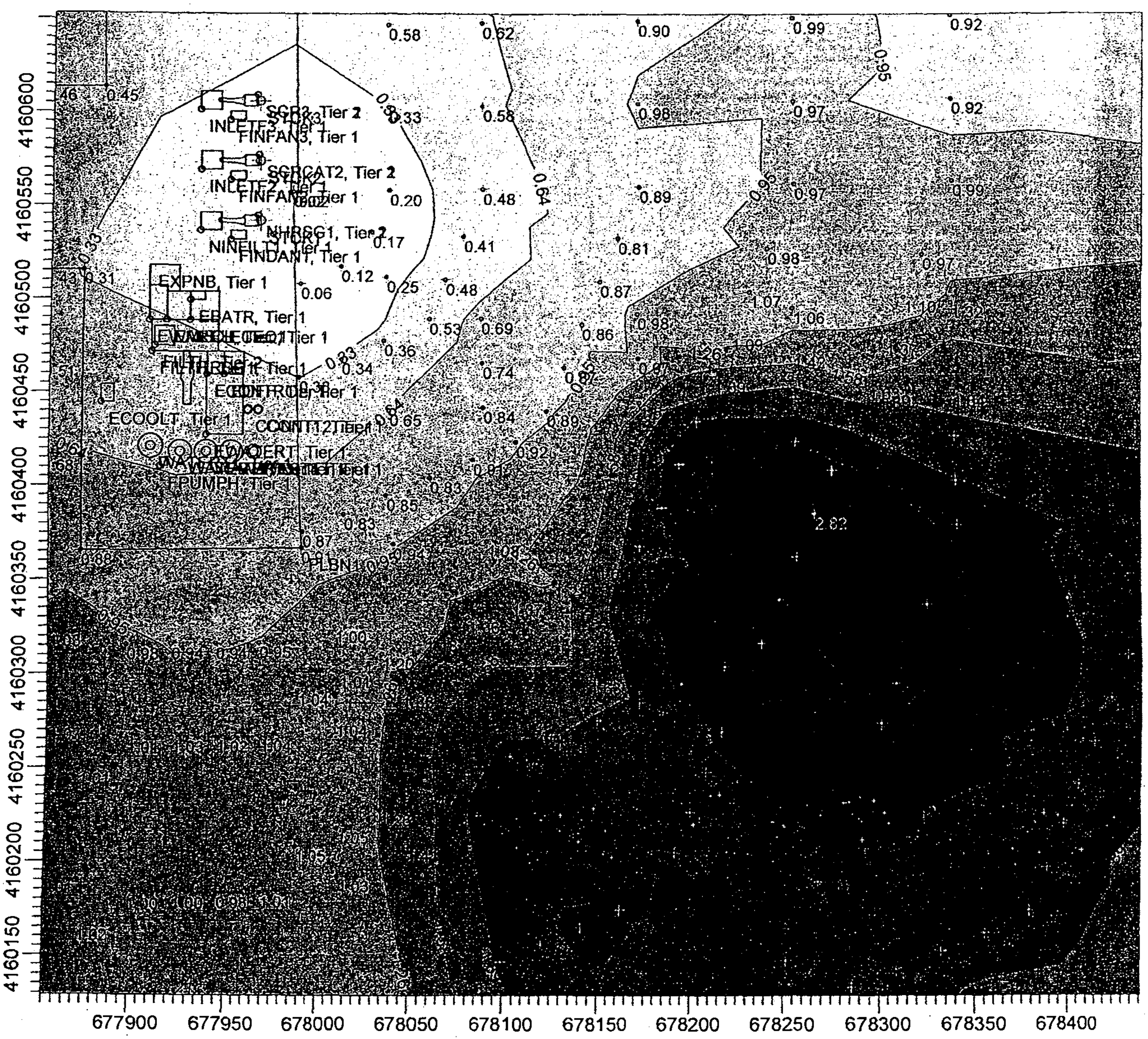
| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 809 | GRID | 3.05E-07 | 2.19E-03 | 4.10E-03 | 678284 | 4160232 | 11 |
| 808 | GRID | 3.02E-07 | 2.16E-03 | 3.89E-03 | 678268 | 4160190 | 11 |
| 800 | GRID | 2.99E-07 | 2.14E-03 | 4.15E-03 | 678216 | 4160270 | 11 |
| 669 | GRID | 2.98E-07 | 2.14E-03 | 3.55E-03 | 678332 | 4160153 | 11 |
| 668 | GRID | 2.96E-07 | 2.13E-03 | 3.57E-03 | 678309 | 4160143 | 11 |
| 799 | GRID | 2.95E-07 | 2.12E-03 | 4.11E-03 | 678208 | 4160248 | 11 |
| 670 | GRID | 2.96E-07 | 2.12E-03 | 3.55E-03 | 678355 | 4160162 | 11 |
| 643 | GRID | 2.92E-07 | 2.10E-03 | 4.42E-03 | 678217 | 4160304 | 11 |
| 667 | GRID | 2.91E-07 | 2.09E-03 | 3.62E-03 | 678286 | 4160134 | 11 |
| 810 | GRID | 2.92E-07 | 2.09E-03 | 4.45E-03 | 678300 | 4160274 | 11 |
| 642 | GRID | 2.90E-07 | 2.08E-03 | 4.13E-03 | 678194 | 4160295 | 11 |
| 671 | GRID | 2.90E-07 | 2.08E-03 | 3.57E-03 | 678379 | 4160174 | 11 |
| 798 | GRID | 2.88E-07 | 2.06E-03 | 4.09E-03 | 678200 | 4160227 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.70E-03 | 678237 | 4160317 | 11 |
| 807 | GRID | 2.86E-07 | 2.05E-03 | 3.78E-03 | 678252 | 4160148 | 11 |
| 672 | GRID | 2.84E-07 | 2.04E-03 | 3.66E-03 | 678388 | 4160197 | 11 |
| 666 | GRID | 2.81E-07 | 2.02E-03 | 3.64E-03 | 678264 | 4160124 | 11 |
| 641 | GRID | 2.81E-07 | 2.01E-03 | 3.93E-03 | 678171 | 4160285 | 11 |
| 811 | GRID | 2.79E-07 | 2.00E-03 | 4.52E-03 | 678308 | 4160295 | 11 |
| 819 | GRID | 2.77E-07 | 1.99E-03 | 3.05E-03 | 678429 | 4160093 | 11 |

RECEPTORS WITH HIGHEST ACUTE HI

| REC | TYPE | CANCER | CHRONIC | ACUTE | UTME | UTMN | ZONE |
|---|---|---|---|---|---|---|---|
| 648 | GRID | 1.90E-07 | 1.37E-03 | 5.13E-03 | 678274 | 4160409 | 11 |
| 751 | GRID | 1.79E-07 | 1.28E-03 | 5.11E-03 | 678255 | 4160424 | 11 |
| 647 | GRID | 2.21E-07 | 1.58E-03 | 5.11E-03 | 678265 | 4160386 | 11 |
| 646 | GRID | 2.48E-07 | 1.78E-03 | 5.01E-03 | 678256 | 4160363 | 11 |
| 645 | GRID | 2.70E-07 | 1.93E-03 | 4.83E-03 | 678247 | 4160340 | 11 |
| 649 | GRID | 1.60E-07 | 1.15E-03 | 4.81E-03 | 678283 | 4160432 | 11 |
| 757 | GRID | 1.97E-07 | 1.41E-03 | 4.75E-03 | 678340 | 4160380 | 11 |
| 750 | GRID | 1.50E-07 | 1.07E-03 | 4.73E-03 | 678254 | 4160448 | 11 |
| 812 | GRID | 2.44E-07 | 1.75E-03 | 4.71E-03 | 678324 | 4160337 | 11 |
| 644 | GRID | 2.86E-07 | 2.05E-03 | 4.70E-03 | 678237 | 4160317 | 11 |
| 455 | GRID | 3.48E-08 | 2.50E-04 | 4.64E-03 | 677746 | 4160876 | 11 |
| 456 | GRID | 3.61E-08 | 2.59E-04 | 4.63E-03 | 677709 | 4160860 | 11 |
| 628 | GRID | 1.77E-07 | 1.27E-03 | 4.62E-03 | 678202 | 4160435 | 11 |
| 454 | GRID | 3.15E-08 | 2.26E-04 | 4.61E-03 | 677783 | 4160892 | 11 |
| 627 | GRID | 2.08E-07 | 1.49E-03 | 4.61E-03 | 678193 | 4160412 | 11 |
| 756 | GRID | 1.72E-07 | 1.23E-03 | 4.60E-03 | 678339 | 4160403 | 11 |
| 340 | GRID | 3.43E-08 | 2.46E-04 | 4.58E-03 | 677747 | 4160837 | 11 |
| 341 | GRID | 3.45E-08 | 2.47E-04 | 4.56E-03 | 677718 | 4160825 | 11 |
| 353 | GRID | 3.39E-08 | 2.43E-04 | 4.56E-03 | 677747 | 4160921 | 11 |
| 354 | GRID | 3.61E-08 | 2.59E-04 | 4.54E-03 | 677717 | 4160908 | 11 |

PROJECT TITLE:

**TID Almond Refined Analysis Normal operation 2004 to 2008 Toxic**



PLOT FILE OF HIGH 1ST HIGH 1-HR VALUES FOR SOURCE GROUP: STCK1 ug/m^3

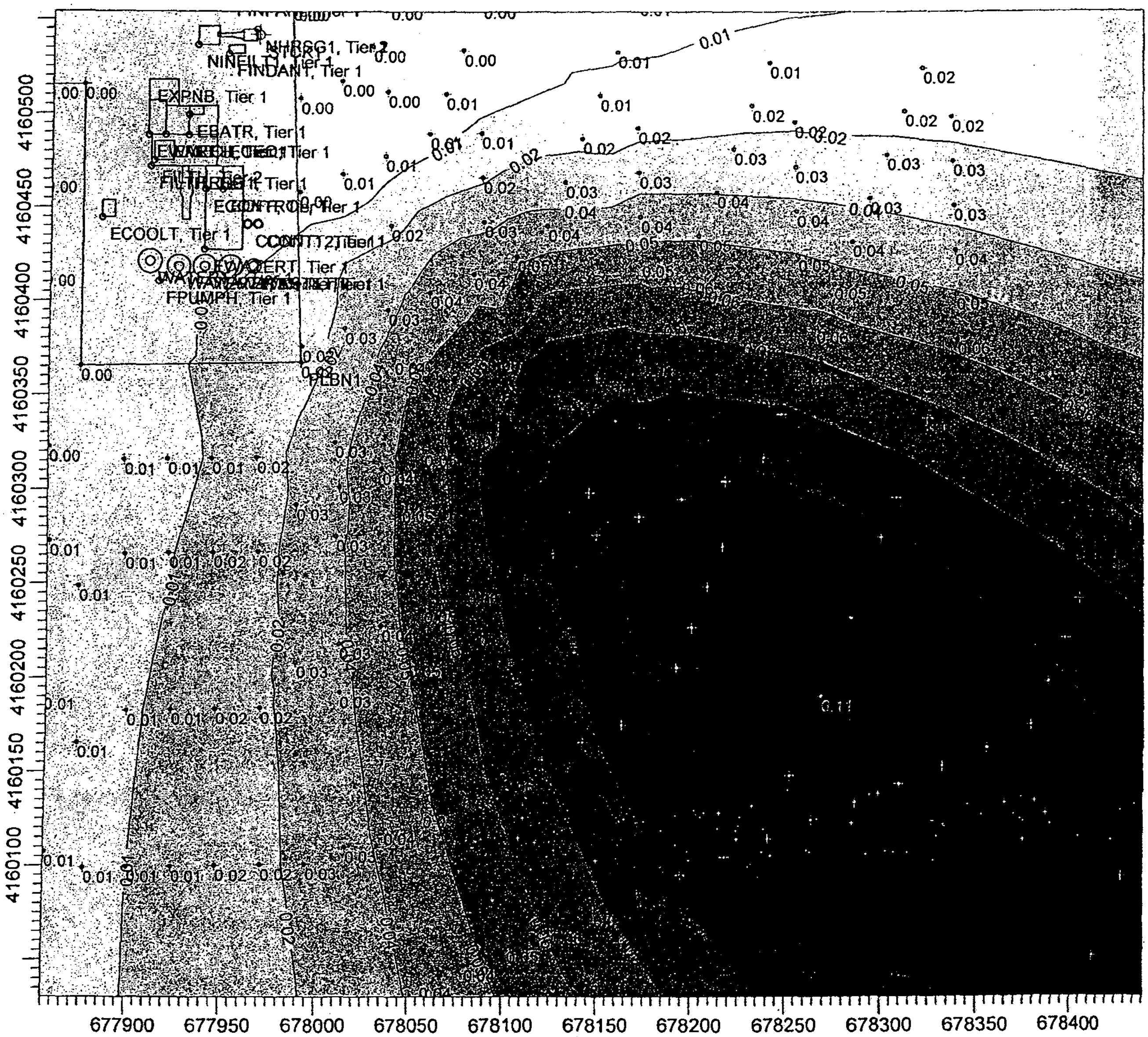
| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.016 | 0.016 | 0.328 | 0.640 | 0.952 | 1.264 | 1.576 | 1.888 | 2.200 | 2.512 | 2.824 |

| COMMENTS: | SOURCES: 3 | COMPANY NAME: Acute Max | |
|---|---|---|---|
| | RECEPTORS: 893 | MODELER: Matthew Cegielski | |
| | OUTPUT TYPE: Concentration | SCALE: 1:3,575 0 — 0.1 km | |
| | MAX: 2.82355 ug/m^3 | DATE: 6/10/2009 | PROJECT NO.: |

AERMOD View - Lakes Environmental Software C:\Program Files\Lakes\AERMOD\Turlock Irrigation District Almond PP\N3299T04.isc

PROJECT TITLE:

**TID Almond Refined Analysis Normal operation 2004 to 2008 Toxic**



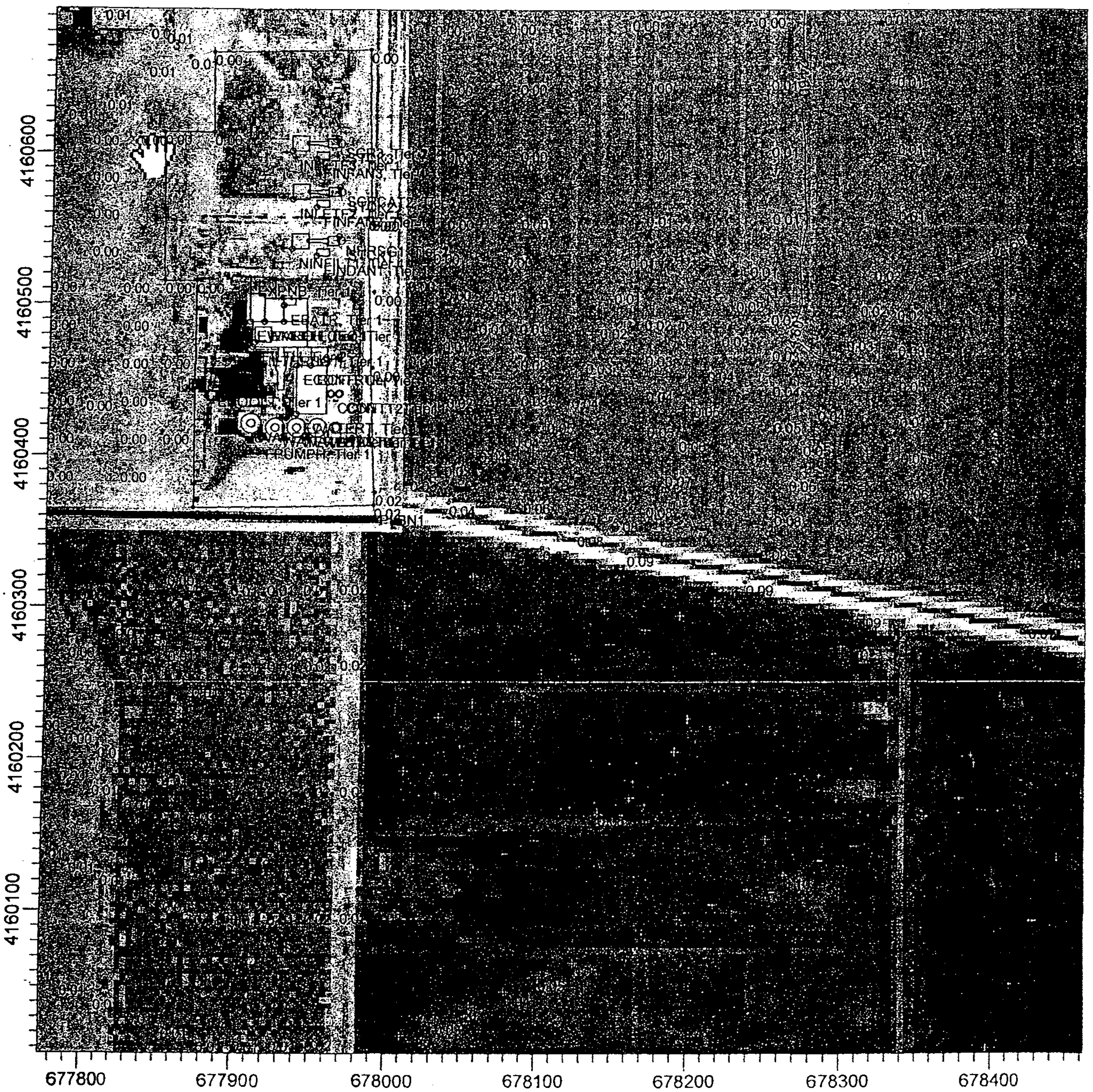

PLOT FILE OF PERIOD VALUES FOR SOURCE GROUP: STCK1 ug/m^3

0.000 0.012 0.024 0.036 0.047 0.059 0.071 0.083 0.095 0.107

| | | | |
|---|---|---|---|
| COMMENTS: | SOURCES: 3 | COMPANY NAME: Chronic Cancer Max | |
| | RECEPTORS: 893 | MODELER: Matthew Cegielski | |
| | OUTPUT TYPE: Concentration | SCALE: 1:3,575 0 0.1 km | |
| | MAX: 0.10676 ug/m^3 | DATE: 6/10/2009 | PROJECT NO.: |

PROJECT TITLE:

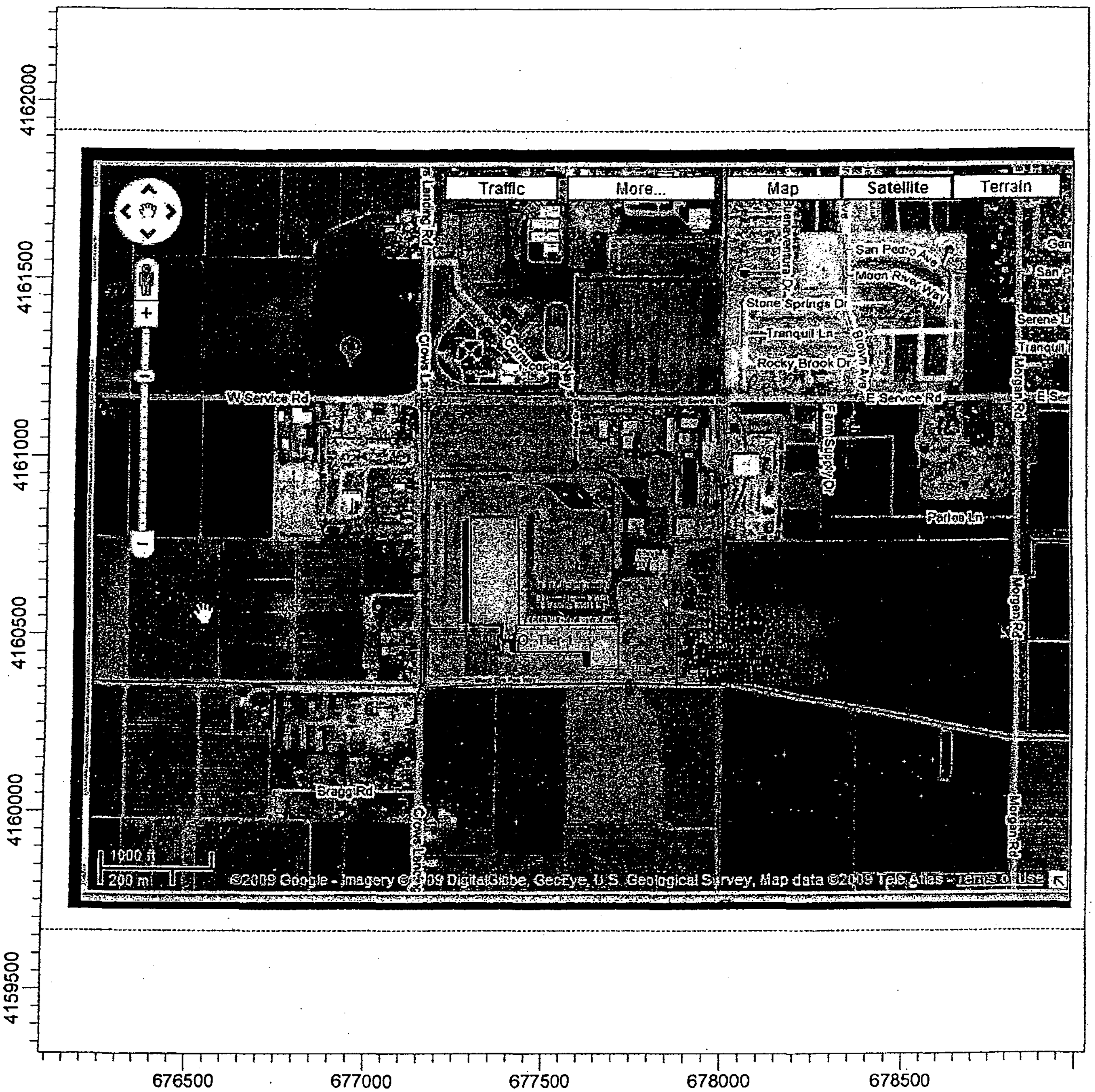
**TID Almond Refined Analysis Normal operation 2004 to 2008 Toxic**




| COMMENTS: | SOURCES: | COMPANY NAME: | |
|---|---|---|---|
| | **3** | | |
| | RECEPTORS: **893** | MODELER: **Matthew Cegielski** | |
| | OUTPUT TYPE: **Concentration** | SCALE: 1:4,205<br>0 — 0.1 km | |
| | MAX: **0.10676 ug/m^3** | DATE: **6/3/2009** | PROJECT NO.: |

PROJECT TITLE:

**TID Almond Refined Analysis Normal operation**




| | | | |
|---|---|---|---|
| COMMENTS: | SOURCES: 3 | COMPANY NAME: | |
| | RECEPTORS: 18 | MODELER: | |
| | | SCALE: 1:17,979<br>0 — 0.5 km | |
| | | DATE: 6/2/2009 | PROJECT NO.: |

# PRIORITIZATION
# FOR

# TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

DEVICE NUMBER 4
DEVICE NAME 54.2 MW NG CTG

| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Emissions and Potency Method Prioritization Scores | | | Despersion Adjustment Method Prioritization Scores | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.05E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 4.92E-02 | 1.10E+00 | 2.05E-01 | 3.35E-01 | 5.53E-01 | 1.05E-01 | 1.71E-01 |
| 71432 | Benzene | 5.18E+01 | 5.91E-03 | 6.38E-01 | 3.70E-03 | 1.70E-03 | 3.22E-01 | 1.89E-03 | 8.69E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 1.94E-02 | 1.94E-01 | 5.20E-03 | 1.54E-02 | 9.80E-02 | 2.65E-03 | 7.87E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.18E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 6.90E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.71E-03 | | 5.06E-01 | 7.06E-01 | | 2.58E-01 | 3.60E-01 |
| 108883 | Toluene | 3.33E+02 | 3.80E-02 | | 4.76E-03 | 3.85E-04 | | 2.43E-03 | 1.96E-04 |
| 110543 | Hexane | 8.02E+03 | 9.15E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.50E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.51E-02 | | 8.12E-04 | 2.58E-04 | | 4.14E-04 | 1.31E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.03E+00 | | 1.32E+00 | 8.24E-01 | | 6.74E-01 | 4.20E-01 |
| | | | TOTALS FOR DEVICE 4 | 2.48E+00 | 2.06E+00 | 1.88E+00 | 1.25E+00 | 1.05E+00 | 9.60E-01 |

DEVICE NUMBER 5
DEVICE NAME 54.2 MW NG CTG

| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Emissions and Potency Method Prioritization Scores | | | Despersion Adjustment Method Prioritization Scores | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.05E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 4.92E-02 | 1.10E+00 | 2.05E-01 | 3.35E-01 | 5.53E-01 | 1.05E-01 | 1.71E-01 |
| 71432 | Benzene | 5.18E+01 | 5.91E-03 | 6.38E-01 | 3.70E-03 | 1.70E-03 | 3.22E-01 | 1.89E-03 | 8.69E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 1.94E-02 | 1.94E-01 | 5.20E-03 | 1.54E-02 | 9.80E-02 | 2.65E-03 | 7.87E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.18E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 6.90E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.71E-03 | | 5.06E-01 | 7.06E-01 | | 2.58E-01 | 3.60E-01 |

# PRIORITIZATION
# FOR

# TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 108883 | Toluene | 3.33E+02 | 3.80E-02 | | 4.76E-03 | 3.85E-04 | | 2.43E-03 | 1.96E-04 |
| 110543 | Hexane | 8.02E+03 | 9.15E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.50E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.51E-02 | | 8.12E-04 | 2.58E-04 | | 4.14E-04 | 1.31E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.03E+00 | | 1.32E+00 | 8.24E-01 | | 6.74E-01 | 4.20E-01 |
| | | | TOTALS FOR DEVICE 5 | 2.48E+00 | 2.06E+00 | 1.88E+00 | 1.25E+00 | 1.05E+00 | 9.60E-01 |

DEVICE NUMBER 6
DEVICE NAME 54.2 MW NG CTG

| | | | | Emissions and Potency Method | | | Despersion Adjustment Method | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Prioritization Scores | | | Prioritization Scores | | |
| CAS NUMBER | POLLUTANT NAME | LBS/YEAR | LBS/HOUR | Cancer | CHRONIC | ACUTE | Cancer | CHRONIC | ACUTE |
| 1151 | PAHs, total, w/o individ. components reported | 9.16E-01 | 1.05E-04 | 4.28E-01 | | | 2.16E-01 | | |
| 50000 | Formaldehyde | 4.31E+02 | 4.92E-02 | 1.10E+00 | 2.05E-01 | 3.35E-01 | 5.53E-01 | 1.05E-01 | 1.71E-01 |
| 71432 | Benzene | 5.18E+01 | 5.91E-03 | 6.38E-01 | 3.70E-03 | 1.70E-03 | 3.22E-01 | 1.89E-03 | 8.69E-04 |
| 75070 | Acetaldehyde | 1.69E+02 | 1.94E-02 | 1.94E-01 | 5.20E-03 | 1.54E-02 | 9.80E-02 | 2.65E-03 | 7.87E-03 |
| 91203 | Naphthalene | 3.66E+00 | 4.18E-04 | 5.30E-02 | 1.75E-03 | | 2.67E-02 | 8.91E-04 | |
| 100414 | Ethyl benzene | 6.05E+01 | 6.90E-03 | 6.42E-02 | 1.30E-04 | | 3.24E-02 | 6.62E-05 | |
| 107028 | Acrolein | 4.12E+01 | 4.71E-03 | | 5.06E-01 | 7.06E-01 | | 2.58E-01 | 3.60E-01 |
| 108883 | Toluene | 3.33E+02 | 3.80E-02 | | 4.76E-03 | 3.85E-04 | | 2.43E-03 | 1.96E-04 |
| 110543 | Hexane | 8.02E+03 | 9.15E-01 | | 4.92E-03 | | | 2.51E-03 | |
| 115071 | Propylene | 4.82E+03 | 5.50E-01 | | 6.90E-03 | | | 3.52E-03 | |
| 1330207 | Xylenes (mixed) | 1.32E+02 | 1.51E-02 | | 8.12E-04 | 2.58E-04 | | 4.14E-04 | 1.31E-04 |
| 7664417 | Ammonia | 6.16E+04 | 7.03E+00 | | 1.32E+00 | 8.24E-01 | | 6.74E-01 | 4.20E-01 |
| | | | TOTALS FOR DEVICE 6 | 2.48E+00 | 2.06E+00 | 1.88E+00 | 1.25E+00 | 1.05E+00 | 9.60E-01 |

# PRIORITIZATION
# FOR

## TURLOCK IRRIGATION DISTRICT
## Project # 1091384
## Region (N) Facility (3299)

### Emissions and Potency Method

**Prioritization Scores**

| Cancer | CHRONIC | ACUTE |
|---|---|---|
| 7.43E+00 | 6.18E+00 | 5.65E+00 |

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor ( Cancer = 1700, Acute = 1500, Chronic = 150)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance

| | RP |
|---|---|
| 0m < R < 100m | 1.0 |
| 100m < R < 250m | 0.25 |
| 250m < R < 500m | 0.04 |
| 500m < R < 1000m | 0.011 |
| 1000m < R < 1500m | 0.003 |
| 1500m < R < 2000m | 0.002 |
| R > 2000m | 0.001 |

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * 1700

Acute Score:
TS(t) = [ EHR(t) / AREL(t) ] * RP * 1500

Chronic Score:
TS(t) = { ( [ EYR(t) / Hours Of Operation ] / CREL(t) ) * RP * 150 }

### Dispersion Adjustment Method

**Prioritization Scores**

| Cancer | CHRONIC | ACUTE |
|---|---|---|
| 3.74E+00 | 3.15E+00 | 2.88E+00 |

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor ( Cancer = 28, Acute = 25, Chronic = 2.5)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
SHA = Stack Height Adjustment ( < 20m = 60, < 45m = 9, >= 45m = 1)
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance
H = Stack Height

For Stack - 0m <= H < 20m

| | RP |
|---|---|
| 0m < R < 100m | 1.0 |
| 100m < R < 250m | 0.25 |
| 250m < R < 500m | 0.04 |
| 500m < R < 1000m | 0.011 |
| 1000m < R < 1500m | 0.003 |
| 1500m < R < 2000m | 0.002 |
| R > 2000m | 0.001 |

For Stack - 20m <= H < 45m

| | RP |
|---|---|
| 0m < R < 100m | 1.0 |
| 100m < R < 250m | 0.85 |
| 250m < R < 500m | 0.22 |
| 500m < R < 1000m | 0.064 |
| 1000m < R < 1500m | 0.018 |
| 1500m < R < 2000m | 0.009 |
| R > 2000m | 0.006 |

For Stack - >= H < 45m

| | RP |
|---|---|
| 0m < R < 100m | 1.0 |
| 100m < R < 250m | 1.0 |
| 250m < R < 500m | 0.90 |
| 500m < R < 1000m | 0.40 |
| 1000m < R < 1500m | 0.13 |
| 1500m < R < 2000m | 0.066 |
| R > 2000m | 0.042 |

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * SHA * 28

Acute Score:
TS(t) = [ EHR(t) / AREL(t) ] * RP * SHA * 25

Chronic Score:
TS(t) = { ( [ EYR(t) / Hours Of Operation ] / CREL(t) ) * RP * SHA * 2.5 }

**Ester Davila**

**From:** Jagmeet Kahlon
**Sent:** Wednesday, May 27, 2009 7:48 AM
**To:** Ester Davila
**Subject:** RMR Project N1091384
**Attachments:** N3299, 1091384_RMR.doc

Ester,

Please process the attached RMR for TID's power plant project. They are proposing to install three 54.2 MW (each) simple cycle gas turbines.

Thanks,
Jag
ext. 6452

# ENGINEERING HRA
# REVIEW & MODELING REQUEST

| | | | |
|---|---|---|---|
| Facility Name: | Turlock Irrigation District (TID) | Process Engineer: | Jag Kahlon |
| Mailing Address: | P.O. Box 949<br>Turlock, CA 95381 | Life Of Project: | |
| Location: | 4500 Crows Landing Rd<br>Modesto, CA | Processing Staff: | |
| Contact Name: | Nancy Matthews, Consultant | Start Date: | 6/5 |
| Telephone: | (916) 444-6666 | Completed Date: | Base map |
| Application #: | N-3299-4, 5-0, 6-0 | Reviewed By: | Jeff adkins jadkins@sierra research.com |
| Project #: | N-1091384 | Date: | |

nmatthews

FAX OR MAIL TO TECHNICAL SERVICES SUPERVISOR

| HRA Information Checklist | Yes | No |
|---|---|---|
| Is all of the following information provided (as applicable)?<br>☒ Receptor distances<br>☒ Stack velocity<br>☒ Stack height<br>☒ Stack temperature<br>☒ Emission/Usage Rates (hour/annual)<br>☒ Hours of Operation<br>☐ MSDS<br>☐ Other (for area sources) | ☒ | ☐ Incomplete (Otherwise, explain under Comments). |
| Supplemental Application Form attached (as applicable)? | ☐ Only HRA cover page is required. | ☒ Submit complete HRA Request Form. |
| Is it obvious that notification is required (NSR, COC, or school)?<br>☒ NSR (Public Notice): *Distances to the fence line in all four directions are required*<br>☒ COC (EPA Notice)<br>☐ School Notice | ☒ | ☐ |
| Has the applicant requested reimbursable overtime processing? | ☐<br>• Get approval from your supervisor.<br>• Send HRA request to Tech Services before deeming complete. | ☒ |
| Supervisor's signature for expedited processing: | | |
| Comments and References: | | |

# SCREENING HRA REQUEST

I. Project Description:

Turlock Irrigation District (TID) is requesting Authority to Construct (ATC) permits for the installation of three 54.2 MW (each), nominal ISO rating, natural gas-fired, simple-cycle, peaking electric generation facility that will consist of General Electric's (GE) natural gas-fired aero derivative LM 6000 PG SPRINT (SPRay INTercoling water injection for increased power output) Combustion Turbine Generators (CTG). Each CTG is equipped with GE's state-of-the art single annular combustors with water injection rated at a combined heat input rate of 523 million British Thermal Units per hour (MMBtu/hr). Exhaust from each CTG will be vented through a Selective Catalytic Reduction (SCR) system for nitrogen oxide (NOx) emissions control, and through an oxidation catalyst to convert carbon monoxide (CO) into carbon dioxide ($CO_2$) gas.

II Receptor Location(s):

| Receptor Description (Units) | Distance From Source (Units) |
|---|---|
| Residence | 1,750 feet - NE 533.4 |
| Business | 600 feet - W 182.9 |

4,581,480
÷ 523 MMBtu/hr
0.523 MMscf
4,581 MMscf/yr

III. Process Rate Or Substances To Be Modeled:

Emissions from **each CTG** are as follows:

| **Potential $NO_X$ Emissions** 1 hr Av | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 25.00 | 50.0 | 2,250 | 2,275 | 2,300 | 2,300 | 9,125 |
| Turbine, Baseload | 4.74 | 104.3 | 9,385 | 9,489 | 9,594 | 9,594 | 38,062 |
| Total: | **154.3** | 11,635 | 11,764 | 11,894 | 11,894 | **47,187** | |

~~6.45~~
~~0.817~~
25
3.15
0.679

| **Potential CO Emissions** 1 hr Av | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 40.00 | 80.0 | 3,600 | 3,640 | 3,680 | 3,680 | 14,600 |
| Turbine, Baseload | 4.61 | 101.4 | 9,128 | 9,229 | 9,331 | 9,331 | 37,019 |
| Total: | **181.4** | 12,728 | 12,869 | 13,011 | 13,011 | **51,619** | |

7.56 lb
0.952
40

| **Potential VOC Emissions** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.00 | 4.0 | 180 | 182 | 184 | 184 | 730 |
| Gas Turbine, Baseload | 1.32 | 29.0 | 2,614 | 2,643 | 2,672 | 2,672 | 10,601 |
| Total: | **33.0** | 2,794 | 2,825 | 2,856 | 2,856 | **11,331** | |

| Potential $NH_3$ Emissions | | | | | | | |
|---|---|---|---|---|---|---|---|
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 7.44 | 14.9 | 670 | 677 | 684 | 684 | 2,715 |
| Turbine, Baseload | 7.01 | 154.2 | 14,511 | 14,672 | 14,833 | 14,833 | 58,849 |
| | Total: | **169.1** | 15,181 | 15,349 | 15,517 | 15,517 | **61,564** |
| **Potential $PM_{10}$ Emissions** 24 hr | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 2.50 | 5.0 | 225 | 228 | 230 | 230 | 913 |
| Turbine, Baseload | 2.50 | 55.0 | 5,175 | 5,233 | 5,290 | 5,290 | 20,988 |
| | Total: | **60.0** | 5,400 | 5,461 | 5,520 | 5,520 | **21,901** |
| **Potential $SO_x$ Emissions** 1 3 24 | | | | | | | |
| Category | Hourly (lb/hr) | PE2 (lb/day) | Q1 (lb) | Q2 (lb) | Q3 (lb) | Q4 (lb) | PE2 (lb/yr) |
| Turbine, startups/shutdowns | 1.56 | 3.1 | 140 | 142 | 144 | 144 | 570 |
| Gas Turbine, Baseload | 1.47 | 32.3 | 3,043 | 3,077 | 3,111 | 3,111 | 12,342 |
| | Total: | **35.4** | 3,183 | 3,219 | 3,255 | 3,255 | **12,912** |

2.5 lb/hr
0.315

0.315

24
1.48 lb/hr
0.186
1.56
0.197

IV. Project Location (Select One): Urban (1) or Rural (2)
2. Rural - area of sparse population

$NH_3$
61,564 lb/yr
7.44
7.03 lb/hr
7634417

V. Point Sources:

For **each CTG:**

| Stack Height (Units) | Inside Diameter (Units) | Gas Exit Velocity (Units) | Gas Exit Temperature (Units) |
|---|---|---|---|
| 80 feet 24.4 | 144 inches | 661,894 cfm | 850 F |
| 120m Dispersion | 3.66 | 29.73 m/sec | 727.4 |

VI: Area Sources[1]:

## Area Parameters:

| Release Height[2] (Units) | Length Of Side (Units) |
|---|---|
| | |

1. An area source is defined as in an area with four equal sides.
2. Release height is defined as the physical height of the source. For example, if a sump has a three meter brim surrounding it. The physical height of the sump is three meters. Height is measured from the ground to the top of the source.

## AAQA for Turlock Irrigation District Almond PP ( N3299 )
## All Values are in ug/m^3

5 year

| | NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|---|
| STCK1 | 1.581E+00 | 5.321E-02 | 2.478E+00 | 1.036E+00 | 4.850E-01 | 3.342E-01 | 1.164E-01 | 1.949E-02 | 1.966E-01 | 3.293E-02 |
| STCK2 | 1.711E+00 | 5.412E-02 | 2.682E+00 | 1.046E+00 | 5.250E-01 | 3.284E-01 | 1.213E-01 | 1.983E-02 | 2.049E-01 | 3.349E-02 |
| STCK3 | 1.637E+00 | 5.401E-02 | 2.567E+00 | 1.034E+00 | 5.025E-01 | 3.028E-01 | 1.217E-01 | 1.978E-02 | 2.055E-01 | 3.342E-02 |
| Background | 1.377E+02 | 2.678E+01 | 8.039E+03 | 4.311E+03 | 1.300E-01 | 7.500E-02 | 3.100E-02 | 7.000E-03 | 9.700E+01 | 3.500E+01 |
| **Facility Totals** | 1.427E+02 | 2.694E+01 | 8.046E+03 | 4.314E+03 | 1.643E+00 | 1.040E+00 | 3.903E-01 | 6.610E-02 | 9.761E+01 | 3.510E+01 |
| **AAQS** | 338 | 56 | 23000 | 10000 | 655 | 1300 | 105 | 80 | 50 | 30 |
| | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Pass** | **Fail** | **Fail** |

0.16 × 1.75
0.28

0.06 × 1.75
0.1

0.1 × 1.1
0.175

### EPA's Significatance Level (ug/m^3)

| NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|
| **0.0** | **1.0** | **2000.0** | **500.0** | **0.0** | **25.0** | **5.0** | **1.0** | **5.0** | **1.0** |

# AAQA Emission (g/sec)

| Device | NOx 1 Hour | NOx Annual | CO 1 Hour | CO 8 Hour | SOx 1 Hour | SOx 3 Hour | SOx 24 Hour | SOx Annual | PM 24 Hour | PM Annual |
|---|---|---|---|---|---|---|---|---|---|---|
| STCK1 | 8.10E-01 | 6.79E-01 | 9.52E-01 | 9.52E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |
| STCK2 | 8.10E-01 | 6.79E-01 | 9.52E-01 | 9.52E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |
| STCK3 | 8.10E-01 | 6.79E-01 | 9.52E-01 | 9.52E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 1.86E-01 | 3.15E-01 | 3.15E-01 |

# ATTACHMENT G
# $SO_X$ FOR $PM_{10}$ INTERPOLLUTANT OFFSET ANALYSIS

# Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

# DEVELOPMENT OF THE INTERPOLLUTANT RATIO

## For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

### March 2009

# Introduction

**Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate**

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

# Analyses included in Interpollutant evaluation

## *Factors Considered*

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

## *Elements from 2008 PM 2.5 Plan*

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

### *Extension by additional analysis*

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

### *Strengths*

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

### *Limitations*

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

## Analyses contained in Receptor modeling

### *Factors Considered*

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

### *Analyses in receptor modeling that use input from regional modeling*

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

### *Extension by additional analysis*

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

### *Strengths*

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

### *Limitations*

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

# Analyses contained in Regional modeling

## *Factors Considered*

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

## *Extension by additional analysis*

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

### *Strengths*

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

### *Limitations*

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

## Results and Documentation

### SJVAPCD Interpollutant Ratio Results

**SOx for PM ratio: 1.000 ton of SOx per ton of PM**

**NOx for PM ratio: 2.629 tons of NOx per ton of PM**

**These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.**

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

# Interpollutant Ratio Issues & Documentation

| | TOPIC | Reference |
|---|---|---|
| 1 | **Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions. | 2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2 |
| 2 | **Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites. | *DV Qtrs* |
| 3 | **Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties. | *Q4 Model Pivot, Model-site chem, Model-Daily Q4* |
| 4 | **Reason for using combined results of receptor and regional model:**<br>Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.<br>Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis. | 2008 PM2.5 Plan, Appendix F<br>2008 PM2.5 Plan, Appendix G |
| 5 | **Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources. | 2008 PM2.5 Plan, Appendix F |
| 6 | **Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods. | 2008 PM2.5 Plan, Appendix G |
| 7 | **Common area of influence adjustments used for all receptor evaluations:**<br>Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2)<br>Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3)<br>Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2)<br>Marine emissions not found present in CMB modeling for this analysis. | Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets |
| 8 | **Variations to reflect secondary area of influence specific to location:**<br>Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources<br>Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources<br>Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2) | Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets |
| 9 | **Reasons for using 2009 Interpollutant Ratio Projection:**<br>2009 Interpollutant ratio is consistent with current emissions inventories<br>Regional modeling does not show a significant change in chemical relationships through 2014. | 2008 PM2.5 Plan<br>*Q4 Model Pivot* |
| 10 | **Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets. | District Rule 2201 Section 4.13.3 |

# ATTACHMENT H
# POTENTIAL TO EMIT OF EXISTING PERMIT UNITS

## Potential to Emit Calculations

**N-3299-1-2**

240 HP CUMMINS DIESEL-FIRED EMERGENCY IC ENGINE WITH TURBOCHARGER AND AFTERCOOLER POWERING A FIRE PUMP

The applicant states that it is a Cummins Model 6CTA8.3-F1 diesel-fueled engine. An identical engine exists at Northern California Power Agency's facility N-2697 (Permit Unit N-2697-4-2). Thus, the fuel use and emissions information from permit unit N-2697-4-2 is used here.

Fuel Use: 11.9 gal/hour

NOx: 6.12 g/bhp-hr
PM: 0.25 g/bhp-hr
CO: 1.45 g/bhp-hr
VOC: 0.46 g/bhp-hr

Assumptions:

- For conservative estimate, all PM is emitted as $PM_{10}$.

Potential Emissions:

Using Table 2, Page 19 of ATCM, non-emergency use of the in-use stationary emergency IC engine should be 21 to 30 hours/year for diesel PM >0.15 g/bhp-hr and ≤ 0.40 g/bhp-hr.

The diesel PM from the engine is 0.25 g/bhp-hr. Therefore, the engine can be operated up to 30 hours/year. Therefore, emissions during non-emergency use are based on 30 hours/year.

PE = (6.12 g-NOx/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 97 lb-NOx/yr

PE = (11.9 gal/hour)(7.1 lb/gal)(0.0015 lb-S/100 lb-fuel)(2 lb-$SO_2$/lb-S)(30 hr/yr)
= 0 lb-$SO_2$/yr

PE = (0.25 g-PM/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 4 lb-PM/yr

PE = (1.45 g-CO/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 23 lb-CO/yr

PE = (0.46 g-VOC/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 7 lb-VOC/yr

**N-3299-3-2**

GENERAL ELECTRIC MODEL LM6000 459 MMBTU/HR (HHV) COMBINED CYCLE GAS TURBINE ENGINE WITH STEAM INJECTION, OXIDIZATION CATALYST, AMMONIA INJECTION, AND SELECTIVE CATALYTIC REDUCTION SERVING A 48 MW ELECTRICAL GENERATOR

Per project N1030015,

PE = 52,049 lb-NOx/yr
PE = 11,459 lb-SOx/yr
PE = 17,520 lb-$PM_{10}$/yr
PE = 136,413 lb-CO/yr
PE = 10,454 lb-VOC/yr

# ATTACHMENT I
# PROPOSED ALTERNATIVE SITING ANALYSIS AND COMPLIANCE CERTIFICATION

SECTION 6.0

# Alternatives

The following section discusses alternatives to Turlock Irrigation District's (TID's) proposed Almond 2 Power Plant (A2PP). These include the "no project" alternative, power plant site alternatives, linear facility route alternatives, technology alternatives, water supply alternatives, and wastewater disposal alternatives. This discussion focuses on alternatives that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects.

The Energy Facilities Siting Regulations (Title 20, California Code of Regulations [CCR], Appendix B) guidelines titled *Information Requirements for an Application* require:

> A discussion of the range of reasonable alternatives to the project, including the no project alternative... which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and an evaluation of the comparative merits of the alternatives.

The data adequacy regulations also require:

> A discussion of the applicant's site selection criteria, any alternative sites considered for the project and the reasons why the applicant chose the proposed site.

According to the Warren-Alquist Act, evaluation of alternative sites is not required when a natural gas-fired thermal power plant is: (1) proposed for development at an existing industrial site, and (2) the project has a strong relationship to the existing industrial site (Public Resource Code 25540.6(b)). The A2PP is a natural gas-fired power plant proposed for development at an existing industrial site; therefore, A2PP is the type of project that is addressed by this code section. The A2PP will be sited at an existing industrial site immediately adjacent to the existing Almond Power Plant. The A2PP has a strong relationship to the existing power plant because the A2PP will be sharing some infrastructure with the existing Almond Power Plant.

Because of these strong relationships, evaluation of alternative sites outside the boundaries of the A2PP is not legally required. However, in accordance with pre-filing guidance from the California Energy Commission staff, a description of alternative sites has been provided.

## 6.1 Project Objectives

The California Environmental Quality Act (CEQA) requires consideration of "a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives" (14 CCR 15126.6(a)). Thus, the focus of an alternatives analysis should be on alternatives that "could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects" [14 CCR 15126.6(c)]. The CEQA Guidelines further provide that "[a]mong the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts."

The A2PP would provide needed electric generation capacity with improved efficiency and operational flexibility. Some of TID's basic project objectives for the A2PP include the following:

- Safely construct and operate a 174-MW, natural gas-fired, simple-cycle generating facility within the TID service territory.
- Provide operating reserves and thus reliability for TID's Balancing Authority requirements.
- Allow for better economic dispatch of TID's existing generation fleet system-wide.
- Provide fast-starting, load-following peaking generating units to help maintain TID's Balancing Authority tie line (interconnection) schedules with neighboring Balancing Authorities (the California Independent System Operator and Sacramento Municipal Utility District)
- Help provide firming sources for TID's existing and future intermittent renewable resources in support of TID's Renewable Portfolio Standard and greenhouse gas goals.
- Provide additional generation to meet TID's growing load and meet the demands of customers within TID's service territory.
- Achieve economies of scale and maximize the use of TID assets by locating the project on an industrial site, with the ability to use existing TID assets and power plant infrastructure.
- Minimize environmental and air quality impacts.
- Assist the State of California in developing increased local generation projects, thus reducing dependence on imported power.
- Contribute to the diversification of the City of Ceres and Stanislaus County's economic base by providing increased employment opportunities and a reliable power supply.

A range of reasonable alternatives are identified and evaluated in this section including the "no project" alternative (that is, not developing a new power generation facility), alternative site locations for constructing and operating the A2PP, alternatives to the linear facilities (transmission lines and natural gas), alternative configurations to the internal combustion engine arrangement currently proposed for the A2PP, and alternative power generation technologies. This section also describes the site selection criteria used in determining the proposed location of the A2PP. Electric transmission connection alternatives are addressed in Section 6.5.2. Gas pipeline connection alternatives are addressed in Section 6.5.3.

## 6.2 The "No Project" Alternative

If the project were not constructed, TID's basic project objectives would not be met. A new natural gas-fired generating facility would not be constructed within the TID service territory. Instead, to meet TID's growing load, TID would need to obtain additional generation from other sources, which are potentially older, less efficient and release larger quantities of air pollutants than the A2PP. Additionally, if the A2PP is not constructed, TID will not be able to rely on its own generating resources to provide needed additional operating reserves and thus reliability for TID's Balancing Authority requirements would not be met with local resources, and there would not be better economic dispatch of TID's existing generation fleet system wide.

The no project alternative could result in greater fuel consumption, air pollution, and other environmental impacts in the state because older, less efficient plants with higher air emissions would continue to generate power instead of being replaced with cleaner, more efficient plants, such as the A2PP. Also, the no project alternative would fail to meet the objective of assisting the state of California in reducing dependence on unreliable imported power. During limited availability of in-state generated electricity, such imported electrical energy has proven to be expensive and inconsistently available. Further, under the no project alternative, TID's Balancing Authority requirements would require uneconomic dispatch of TID's existing generation fleet, as well as reliance on imported energy. This alternative would fail to improve the County's economic base because no new jobs would be created and the reliability of the regional power supply would not be increased.

## 6.3 Power Plant Site Alternatives

Several alternative site locations were assessed during initial screening for the A2PP project. This initial screening identified the A2PP site and three alternatives. The alternative sites are shown in Figure 6.3-1. Although each of the alternative sites could feasibly attain most of the project's basic objectives, the A2PP site clearly became the preferred alternative for a variety of reasons, including the ability to use a previously disturbed site, the best and cost-effective use of existing facilities and infrastructure, and the least environmental impacts.

The key screening criteria used to select the A2PP site and alternative sites included:

- Location within TID's service territory
- Ability to gain site control
- Availability of sufficient land area
- Ability to share facilities and infrastructure with existing generating facilities
- Proximity to existing transmission and distribution lines and close to a substation
- Location near a source of water supply of sufficient quantity and water quality
- Consistency with the City of Ceres and Stanislaus County General Plans, zoning ordinances, and existing land uses

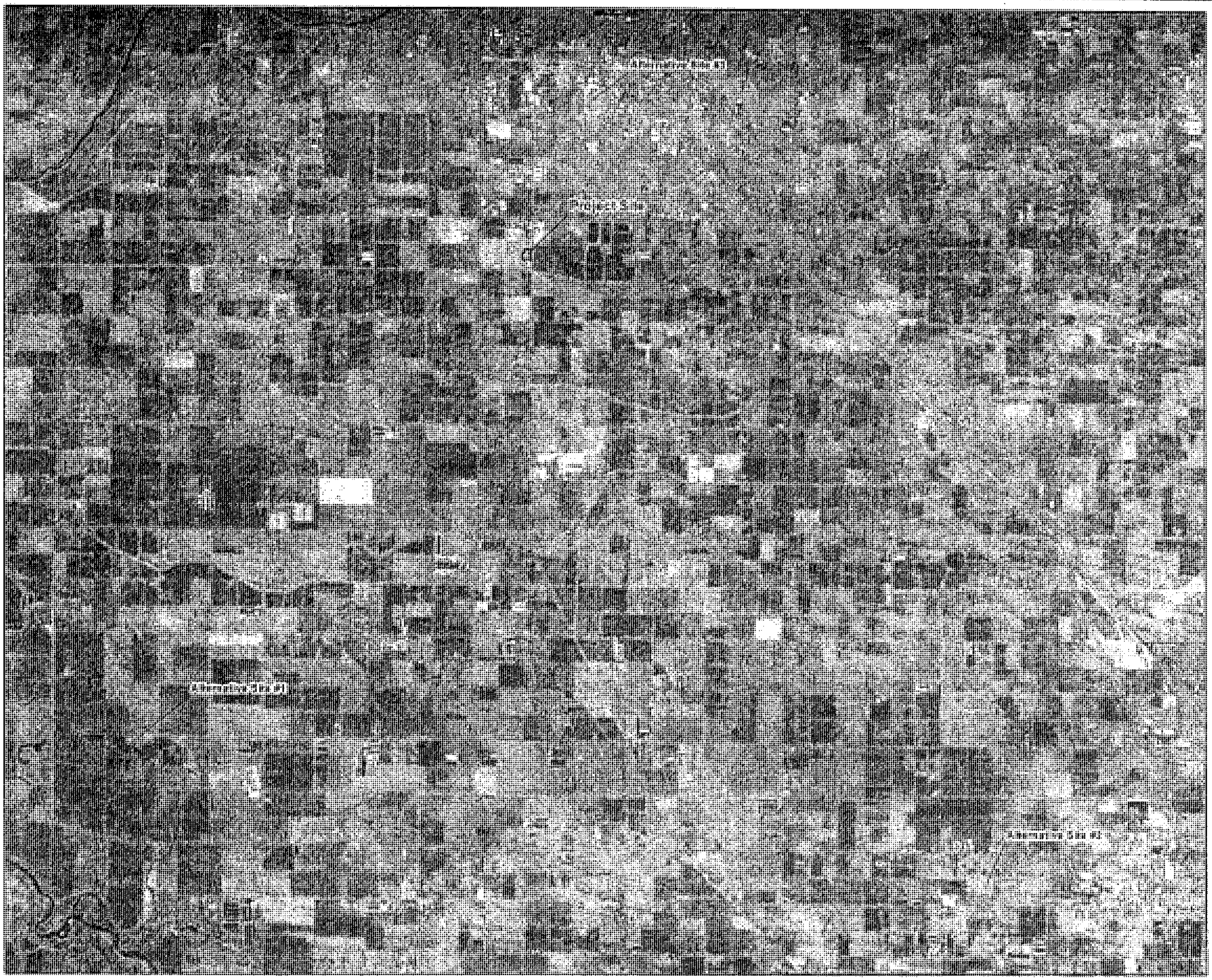
- The ability to avoid or minimize potentially significant impacts on the environment
- Location in an area appropriate for industrial development, preferably a previously disturbed site.

### 6.3.1 The A2PP Site

The A2PP site is described in detail in Section 2.0, Project Description. To summarize briefly, the A2PP site is located at the southwestern edge of Ceres, approximately 2 miles from the Ceres city center. The city of Modesto is approximately 5 miles to the north. The site is approximately 4.6 acres and bordered by the existing 48-MW Almond Power Plant to the south, a WinCo distribution warehouse to the west, a farm supply facility to the north, and various industrial facilities (modular building distributor and drilling equipment storage laydown areas) to the east. Immediately south of the existing Almond Power Plant is the TID Lower Lateral 2, an irrigation canal, with adjacent transmission lines. The general plan designation and zoning of the site are "Industrial" and several tall industrial structures are within 0.2 mile of the site. The nearest residential uses to the project are located approximately 0.3 mile north of the project. The project site was previously used by WinCo as a borrow pit during construction of the WinCo distribution warehouse. The site was filled and graded to the current site elevation in 2008, using approximately 30,000 cubic yards of commercially available soil.

The proposed location of the A2PP site provides the opportunity to share the following facilities between the existing Almond Power Plant and the A2PP:

- The anhydrous ammonia system, including the 12,000-gallon storage tank and unloading facilities
- The fire protection system, including fire water storage tank and diesel-fired emergency fire pump
- The well water for service water and emergency shower / eyewash stations
- The water treatment system
- The recycled water supply and wastewater discharge systems
- The process water system (process water for the A2PP will be provided using the existing system in place between the Almond Power Plant and the City of Ceres Wastewater Treatment Plant [WWTP])
- The instrument and service air systems
- The oil/water separator
- The demineralized and reverse osmosis water storage tanks
- The administration building, including the control room and office space




LEGEND
Alternative Site #1
Alternative Site #2
Alternative Site #3
Project Site

N

0 2,500 5,000
Feet

**FIGURE 6.3-1**
**ALTERNATIVE SITE LOCATIONS**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

CH2MHILL

The A2PP will be interconnected to the TID system via two 115-kilovolt (kV) lines (Corridor 1, 0.9 miles long, and Corridor 2, 1.2 miles long; see Figure 1.1-3) to the proposed Grayson Substation.[1] Load flow studies indicate that the existing Almond-Crows Landing 69-kV line will need to be reconductored to prevent possible thermal overload under certain contingencies, as described in more detail in Section 3.0, Electric Transmission.

Natural gas will be provided via one of two routes:[2] an approximately 9.1-mile-long gas pipeline that runs south along Crows Landing Road (Alternate A), or an approximately 11.1-mile-long gas pipeline that runs south along Carpenter Road (Alternate B). Both natural gas alternatives will connect to Pacific Gas and Electric Company (PG&E) Line #215 located in Bradbury Road to the south of the project. More information regarding the natural gas supply can be found in Section 4.0, Natural Gas Supply.

Process water will be obtained by tying into the existing water treatment system for the Almond Power Plant, which uses recycled water from the City of Ceres WWTP, 0.5 mile away. Wastewater will be returned to the City of Ceres WWTP via an existing pipeline connection at the Almond Power Plant. Service water for the facility will be provided by an existing well at the southeast corner of the Almond Power Plant property. Potable water will be delivered to the A2PP by a commercial vendor. The A2PP will generate no sanitary wastewater because the sanitary facilities at the existing Almond Power Plant will be used. Sanitary wastewater for the existing Almond Power Plant is currently discharged to an onsite septic tank and leachfield.

### 6.3.2 Alternative 1: Modesto WWTP Site

The Modesto WWTP site is located 100 yards southwest of the corner of Fulkerth and Vivian roads, 8.4 miles southwest of Ceres. The site is a greenfield site located on approximately 8 acres of "high ground" elevated above the surrounding area. To the south and west, the fields of alfalfa are irrigated with wastewater and drain to an unnamed meandering channel that is also south of the site. The soils on the elevated portion are whitish and are reported to be alkaline and salty, and therefore, undesirable for planting. The drainage canal immediately to the south is 20 feet wide in places, and supports a lush growth of dense bulrushes, and willow scrub. The site is in unincorporated Stanislaus County and currently zoned for agriculture. A power plant would be consistent with the zoning, but would be subject to meeting the requirements for a use permit. The nearest residences are located approximately 0.25 mile north of the site. Site control may be possible through negotiations with the Modesto WWTP staff and City Council. Water for this site would come from the Modesto WWTP located approximately one mile north of the site. Wastewater would be returned to the Modesto WWTP or treated through a zero-liquid discharge (ZLD) system.

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[1] The proposed Grayson Substation is a component of the TID Hughson-Grayson 115-kV Transmission Line and Substation Project. In addition to the substation, the Hughson-Grayson project consists of an approximately 10-mile-long, 115-kV transmission line; a 0.5-mile-long, 69-kV transmission line from the existing TID Almond Power Plant; and a second 69-kV transmission line that extends 0.8 mile east from the proposed substation. An environmental impact report for the Hughson-Grayson project (State Clearinghouse Number 2009012075) is currently being prepared. The Notice of Preparation was issued on January 26, 2009, and reissued February 10, 2009. The Draft Environmental Impact Report is anticipated to be issued in July 2009.

[2] Pacific Gas & Electric Company (PG&E) is currently examining the relative strengths of the two alignments. In order to allow the AFC to proceed, the two possible alternatives are presented in this AFC with same level of detail to allow complete evaluation of both alternatives. TID anticipates that PG&E will select a preferred route in late spring or early summer 2009. At that time, the route not selected will provide information for the California Energy Commission's Alternatives analysis.

The site would require two new 9-mile-long, 115-kV transmission line interconnections for connection to the Walnut Substation. A new 6-mile-long natural gas pipeline would need to be constructed to PG&E's Line #215 located along Bradbury Road.

### 6.3.3 Alternative 2: Washington Road Site

The Washington Road site is located on a 40-acre parcel on the west side of Washington Road and south of the Tidewater Southern Railroad tracks and the existing TID Walnut peaking plant. This site is located at the western edge of Turlock, in Stanislaus County, approximately 1.9 miles west of Highway 99, just south of West Main Avenue.

The site is zoned for agricultural use and is currently farmed. Agricultural uses are located south, east, and west of the site, with utility uses to the north. The site is adjacent to a major 115-kV transmission line that connects to the existing Walnut peaking plant and substation. A 115-kV interconnection would be less than 0.1 mile. Natural gas would be supplied via an approximately 3.7-mile-long gas pipeline that would tie into PG&E Line #215 on Bradbury Road. Water supply would be obtained from the Turlock WWTP, located about 2 miles east. Effluent from the plant would be treated using a ZLD system. It is unknown if site control would be possible at this site.

The site is near an industrial area of Turlock that has several tall industrial structures within the context of mixed residential and industrial uses. The nearest residences are two homes located on the 40-acre Washington Road site approximately 800 feet west of the project. Additional residences are located less than 950 feet south of the project. There are up to six other residences within 2,000 feet.

### 6.3.4 Alternative 3: Morgan Road

The Morgan Road site is located northeast of the junction of Morgan Road and East Whitmore Avenue in Ceres, approximately 0.75 mile west of Highway 99. The site is approximately 18.7 acres and currently vacant. Non-native grasses are the dominant vegetation onsite. Bordering the property are a residential subdivision to the south, vacant industrial-designated land to the east, a storage yard to the north, and unincorporated agricultural land to the west. The site is designated General Industrial and zoned M-2 General Industrial, except for the portion adjacent to Whitmore Avenue, which is addressed by a specific plan (PC-29). The General Industrial and M-2 zoning designations would support a power plant. It is unknown if site control would be possible at this site.

The site is located in a predominantly industrial area with several large industrial buildings to the east of the site. The nearest residences are located less than 0.1 mile to the south. An 11.5-mile-long natural gas pipeline connecting to PG&E's Line #215 would need to be constructed to this site along Crows Landing Road, as would two, 3.2-mile-long, 115-kV transmission lines that would connect to the proposed Grayson Substation located east of the intersection of Crows Landing Road and Grayson Road. A 1.5-mile-long recycled water line would be required to connect to the Ceres WWTP. Effluent from the plant would be sent back to the Ceres WWTP via a new approximately 1.5-mile-long pipeline.

# 6.4 Comparative Evaluation of Alternative Sites

In the discussion that follows, the sites are compared in terms of each of the 16 topic areas required in the AFC including the following:

- **Land Use Compatibility**—Is the parcel zoned appropriately for industrial use and compatible with local land use policies?
- **Routing and Length of Linear Facilities**—Can linear facilities be routed to the site along existing transmission lines, pipelines, and roads? Will linear facilities be significantly shorter for a given site?
- **Visual Resources**—Are there significant differences between the sites in their potential for impact on significant or protected viewsheds?
- **Biological Resources**—Would there be significant impacts to wetlands or threatened or endangered species?
- **Contamination**—Is there significant contamination onsite, such that cleanup expense would be high, cleanup would cause significant schedule delay and will the use of the site expose TID to potential liability for site cleanup?
- **Noise**—Is the site sufficiently near a sensitive receptor area such that it would be difficult to mitigate potential noise impacts below the level of significance?
- **Use of Previously Disturbed Areas**—Has the site been previously disturbed? Does the site minimize the need for clearing vegetation and otherwise present low potential for impact on biological and cultural resources?

## 6.4.1 Overview of the A2PP and Alternative Sites

As indicated in the descriptions of each of the alternative sites, the basic needs of a power plant project for land, access to electrical transmission, gas supply, and water, are met at each site. All of the alternatives would require construction of new transmission lines and a natural gas pipeline.

The site characteristics are summarized in Table 6.4-1 and described in the following subsections.

**TABLE 6.4-1**
Overview of Alternative Sites

| Alternative Site | Site Size (acres) | Land Use Compatibility | Estimated Lengths of Linear Facilities |
|---|---|---|---|
| A2PP (proposed site) | 4.6 | Zoned: M-2 General Industrial, vacant land | W: 0.5 mi (existing)<br>G: 9.1 mi/11.1 mile<br>T: 115-kV: 0.9 mile<br>115-kV: 1.2 mile |
| Alternative 1: Modesto WWTP | 8 | Zoned: AG-2-40; currently fallow | W: 1 mile<br>G: 6 miles<br>T: 9 miles |

**TABLE 6.4-1**
Overview of Alternative Sites

| Alternative Site | Site Size (acres) | Land Use Compatibility | Estimated Lengths of Linear Facilities |
|---|---|---|---|
| Alternative 2: Washington Road | 40 | Zoned: AG-2-40; currently farmed, Prime Farmland | W: 2 miles<br>G: 3.7 miles<br>T: 115 kV <0.1 mile (300 ft) |
| Alternative 3: Morgan Road | 18.73 | Zoned: General Industrial and PC-29 vacant | W: 1.5 miles<br>G: 11.5 miles<br>T: 115 kV 3.2 miles |

W: = recycled water; G: = natural gas; T= transmission.

## 6.4.2 Air Quality

The plant's configuration and operation would be essentially the same from an air quality perspective at every location. All of these sites are in the same air basin (San Joaquin Valley Air Basin) and offsets acquired by TID would be equally appropriate for every site. The type and quantity of air emissions from the alternative sites would be identical. The impacts on the human population and the environment may differ slightly because of the location of residences and other human uses in the project vicinity. The A2PP site is located the farthest from the nearest residence (1,580 feet). The alternative sites would be located 300, 800 or 1,300 feet from the nearest residence. Local terrain is similar at all sites and not likely to change air quality impacts.

## 6.4.3 Biological Resources

Special-status species that are recorded, or that potentially occur in the region, are the same for all sites.

The sites differ in their proximity and abundance of either onsite or adjacent habitat that is relatively natural or undeveloped. The A2PP site is located within a site that has been graded and has little to no biological value. The project site does not contain any wetlands or suitable habitat for sensitive plant or wildlife species and would not cause an adverse impact to sensitive biological resources.

The greatest impact on biological resources would be expected for development of the Modesto WWTP site because of the close proximity of abundant wetland and riparian habitat to the south and west. The wetlands and riparian habitats are several acres in size, and lead directly to the San Joaquin River. Species expected in this area would include cottonwoods, willows, sedges, reeds; water fowl such as great blue herons, great egrets; and songbirds such as red-winged blackbirds, flycatchers, and grosbeaks.

The Washington Road Site would have low impact to biological resources because it is actively farmed, and supports little natural biological habitat.

The Morgan Road site is located in close proximity to industrial, residential, and agricultural development. The site has experienced disturbance and biological value is considered low. However, based on a preliminary site assessment, California ground squirrels were observed, which can be an indicator of burrowing owl. Additional site surveys in accordance with biological survey protocols would be essential if site development were to occur.

### 6.4.4 Cultural Resources

The A2PP site is located within an industrial area surrounded by industrial facilities. The site was recently used as a borrow pit during the construction of the WinCo distribution warehouse to the west, and was filled in 2008. There is an overall low density of previous finds in this general area, despite previous surveys.

Due to its location adjacent to the San Joaquin River and above the flood plain, the Modesto WWTP site is the most likely to have cultural resources present. The Washington Road site is located in fields that are actively farmed; and the surface soils have been graded, harrowed, and planted. The Morgan Road site is in a predominantly industrial area with residential development occurring in the area within the past 20 years.

A record search of the area was performed by staff of the Central California Information Center, California Historical Resources Information System (Department of Anthropology, California State University, Stanislaus—CCIC File # 4620N). The records search shows no known/recorded cultural resources within a 0.5 mile radius of the A2PP or alternative sites. Table 6.4-2 provides a compilation of known cultural resources and surveys for each alternative site

**TABLE 6.4-2**
Cultural Surveys and Known Cultural Resources at Alternative Sites

| Power Plant Site | Previously Surveyed | Known/Recorded Cultural Resources within 0.5-mile radius |
|---|---|---|
| A2PP | Surveyed in 2009 | None |
| Alternate 1: Modesto WWTP | Unsurveyed | None |
| Alternate 2: Washington Road | Nearby area was partially surveyed in 1995 with negative findings | None |
| Alternate 3: Morgan Road | Unsurveyed | None |

### 6.4.5 Geological Resources and Hazards

There are no significant differences in the geological resources present at each site. Thus, there is no significant difference in the effects of the proposed A2PP site and the three alternatives on geologic resources.

### 6.4.6 Hazardous Materials Handling

There would be no significant difference between the site locations in terms of hazardous materials handling. The uses of hazardous materials would be the same for any of the sites.

### 6.4.7 Land Use and Agriculture

The A2PP and the Morgan Road site are located in Ceres. The Washington Road site and the Modesto WWTP site are located in Stanislaus County. A summary of the land use status of the sites issues is provided in Table 6.4-3.

**TABLE 6.4-3**
Land Use Status of Sites

| Site Location | FMMP Designation | Zoning | General Plan | Entitlements Required |
|---|---|---|---|---|
| A2PP | Urban Built Up | M-2, General Industrial | General Industrial | None |
| Alternate 1: Modesto WWTP | N/A | AG-2-40 | Agriculture | Use Permit |
| Alternate 2: Washington Road | Prime Farmland | AG-2-40 | Agriculture | Rezone |
| Alternate 3: Morgan Road | Urban Built Up | M-2, General Industrial | Industrial | Potentially change to PC-29 if development occurs within boundaries of PC-29 (along Whitmore Ave.) |

The A2PP site is designated General Industrial and has been heavily disturbed due to surrounding land uses, including the construction of the WinCo distribution warehouse to the west. The Modesto WWTP site is located on an outcrop of alkaline soils that is unsuitable to support prime agriculture, but is surrounded by soils classified as Prime. The site is also designated and zoned for agriculture. The Washington Road and Modesto WWTP sites are zoned for agriculture (AG-2-40), but neither has a Williamson Act contract. The Modesto WWTP is an outcrop of alkaline soils that is unsuitable to support prime agriculture, but is surrounded by soils classified as Prime. The Washington Road site is designated as Prime Farmland. Per Stanislaus County zoning code section 21.20.030, "Uses requiring use permit," power plants are permitted in the A-2 zoning, and require a use permit if the site is not on Williamson Act land and if it does not affect prime agricultural uses (located within a city sphere of influence and/or the agricultural use will not be taken out of use for long-term) (Doud, 2009). Hence, the Washington Road site would require rezoning, whereas the Modesto WWTP site would only require a use permit.

Since the Modesto WWTP site does not have either a Williamson Act contract, and is not on prime agricultural land, a power plant at this site would be a permitted use, but would require a use permit.

Although the Washington Road site does not have a Williamson Act contract, it is located on Prime Farmland. Therefore, a power plant at the Washington Road site would not be a permitted use based on the zoning of the parcel, and the site may need to be rezoned.

The Morgan Road site is zoned for general industrial development and includes a specific plan for the portion of the site adjacent to Whitmore Avenue. It has been heavily disturbed due to surrounding land uses and is essentially a weedy, fallow field.

### 6.4.8 Noise

The A2PP is located approximately 0.3 mile (1,580 feet) from the nearest residences to the northeast. However, the residents are separated from the A2PP by several industrial facilities including the Stanislaus Farm Supply, Inc.

There is one residence within 1,300 feet of the Modesto WWTP site. Due to the lack of development in the area, the ambient noise level is relatively low. The power plant would add a dominant noise source to a predominantly rural agricultural area.

At the Washington Road site, assuming that only approximately 5 acres on the western boundary of this property would be needed to site the proposed plant, the two residences located on the eastern border of the parcel would be the nearest residents at approximately 800 feet. In addition, several other houses are located approximately 950 feet to the north and south of this site. A 20-acre area to the south of the plant would act as a buffer between the plant and residential/agricultural uses to the south. The rail spur would not affect ambient nighttime noise levels because of its sporadic use.

The Morgan Road site is located approximately 300 feet north of a residential subdivision in a predominantly industrial area; however, no sound walls or other barriers (warehouses, industrial buildings) are present between the subdivision and this alternate site. Ambient noise levels at this location would also be affected by local traffic on Morgan Road and East Whitmore Avenue. Therefore, the power plant would add another dominant noise source to this industrial area. Further detailed noise analysis could result in options for mitigating noise, such as acoustical enclosures around equipment.

### 6.4.9 Paleontology

The A2PP site is a former borrow pit for the adjacent WinCo distribution warehouse that was filled in 2008. As a result of this fill, there is little to no potential for paleontological resources at the project site. The remaining alternate sites, are considered to have an equally low potential for paleontological impacts.

### 6.4.10 Public Health

The A2PP, Modesto WWTP, and Washington Road sites are remote from large residential areas, schools, hospitals, churches, or other facilities that would potentially be considered sensitive receptors for public health. The Morgan Road site is located about 300 feet from the nearest residence and would require additional evaluation to determine potential impacts on residents at this proximity. Public health impacts are generally related to air quality. If a power plant were located at any of the three alternative sites, it would require an emergency diesel fire pump, which could create a new emissions source having substantial public health impacts. Hence, all three alternative sites are less desirable than the A2PP.

### 6.4.11 Socioeconomics

The A2PP and three alternative sites are located in Stanislaus County. The closest large urban area to all of these sites is the greater Modesto/Turlock area. Therefore, it is likely that most purchases for construction and operation equipment and supplies would be made in the greater Modesto/Turlock area. Since the point of sale and the county of sale receive the greater portion of sales taxes that are not retained by the state, the local impacts would be similar among the alternatives. Both the A2PP and the Morgan Road site are located in Ceres, so purchases made within the City of Ceres would result in a small increase of sales tax to the City.

Workforce would likely come from Stanislaus, Ceres, Merced, San Joaquin, Fresno, and possibly the San Francisco Bay Area. However, due to the proximity of these sites to one another, the origin of the workforce would not change among the alternative sites.

Because TID is a public agency, it does not pay property taxes. Therefore, no jurisdiction would receive property taxes from this plant and there would be no difference among the alternate sites.

### 6.4.12 Soils

The A2PP and three alternative sites would manage stormwater at all locations by onsite retention ponds and implementation of best management practices to minimize soil erosion. Therefore, impacts to soil resources are expected to be comparable among all of these sites.

### 6.4.13 Traffic and Transportation

The A2PP and three alternative sites are accessible from Highway 99 and Interstate 5. The A2PP site is accessible from both Highway 99 and Interstate 5 from the Crows Landing Road on- and off-ramps. The Modesto WWTP site, is not directly off collector boulevards requiring more travel on 2-lane roads. The Washington Road site, is located off main roads (Crows Landing and West Main), which both have exit ramps on Highway 99. The Morgan Road site is accessible from Highway 99 from the El Camino Avenue on- and off-ramps. However, the entire area is served through a north/south, east/west grid of roads making construction traffic easily dispersed throughout the road network.

A spur of the Tidewater Southern Railroad lines serves the Washington Road site. The rail line provides service to the Foster Farms granary and other industrial facilities to the east. Access to the Washington Road site from West Main Avenue would require crossing this spur. However, the spur is infrequently used and has crossing arms. The other alternative locations and the A2PP site do not have easily accessible rail lines.

Because the A2PP will share staffing resources with the Almond Power Plant, this site will require fewer vehicle trips once the plant is operational. The three alternative sites, which will not share staffing resources, will require additional vehicle trips during operations.

### 6.4.14 Visual Resources

The potential for visual resource impacts associated with each of the sites varies depending on the relative visibility of the sites from roads and residences and the length and potential visibility of any new transmission lines that the power plant would require. Visual impacts are also a function of the surrounding facilities.

The A2PP would be located within an industrial area, and is screened by the WinCo distribution warehouse to the west, the Almond Power Plant to the south, and the Stanislaus Farm Supply to the north. Several smaller industrial facilities (a modular building facility and a drilling equipment laydown storage area) are located to the east, as well as the

Ceres WWTP. Two transmission lines would be needed at this site, at 0.9 mile and 1.2 miles, and would be located near existing transmission lines tying into the Almond Power Plant.

The Modesto WWTP site is slightly elevated and can be seen in the distant views by those traveling east on West Main Avenue. In addition, this location would require the construction of an 8-mile-long transmission line adjacent to predominantly agricultural fields. There are limited sensitive receptors in the vicinity.

The Washington Road site would be adjacent to the existing Walnut peaking plant. It would be in an area that has already been converted to utility uses and is adjacent to the City of Turlock's industrial area. Transmission lines for this site would be short, as this site could tie directly into the substation adjacent to the Walnut peaking plant, less than 200 feet to the north.

The Morgan Road site is very visible from the residential neighborhood to the south. It is bordered to the east and north by larger industrial buildings. Open agricultural land is located immediately to the west. Less than a half-mile to the east (past the agricultural property) is a cluster of large industrial buildings. At this location, the project would be similar with the size and scale of the adjacent industrial buildings; however, it would increase the industrial character of the area. In addition, this site would be located less than 300 feet from the nearest residence, with no screening available from warehouses or other industrial buildings.

### 6.4.15 Water Resources

Process water would be supplied to the A2PP using a tie-in to the existing water system between the Almond Power Plant and the Ceres WWTP. The three alternative sites would require water from the Modesto WWTP (Alternative 1), the Turlock WWTP (Alternative 2, Washington Road), or the Ceres WWTP (Alternative 3, Morgan Road). Therefore, all sites are generally equivalent with respect to availability of recycled water; although, the A2PP has the added benefit of tying into an existing water line rather than having to construct a new line. For disposal of process wastewater, the A2PP and Alternative 3 would be able to send the water back to the Ceres WWTP. Alternatives 1 and 2 could require the use of a ZLD system, which would result in reduced efficiency and increased solid waste production. In the event that the concentrations of total dissolved solids (TDS) or nitrate in process wastewater from the Modesto WWTP site are too high, it would have to be treated onsite using ZLD. Due to high levels of nitrates, the respective wastewater treatment providers for Alternatives 1 and 2 may not be willing to accept wastewater for treatment, requiring the use of other water-treatment technology.

### 6.4.16 Waste Management

The same quantity of waste will be generated at the proposed site as at all alternative sites. The environmental impact of waste disposal would not differ significantly between the alternative sites.

### 6.4.17 Summary and Comparison

Although each of the alternative sites is feasible and could meet some, if not all, of the basic project objectives, the A2PP site is clearly the preferred alternative for a variety of reasons.

The Modesto WWTP site was rejected because this site has the potential for the greatest impact on biological resources due to its close proximity to abundant wetland and riparian habitat to the south and west. These wetlands and riparian habitats are several acres in size, and lead directly to the San Joaquin River. In addition, due to the proximity of the site to the San Joaquin River, this site had the greatest potential for impact to cultural resources. It is also in the most rural location, which would be a significant change to the character of the area. The Modesto WWTP site would require a much longer transmission line for interconnection (approximately 8 miles long, compared to 0.9 or 1.2 miles for the A2PP transmission line). This site would also require the installation of the diesel-fired fire pump, increasing the diesel particulates in the area and potential public health impacts. Finally, the Modesto WWTP site offers no opportunity to share staff and infrastructure with existing TID generating facilities.

The Washington Road site was rejected because the site is zoned agricultural and is designated as prime farmland. Therefore, a power plant is not consistent with the zoning. Another factor weighing against the Washington Road site is its proximity to residences. Assuming that only approximately 5 acres on the western boundary of this property would be needed to site the proposed plant, the two residences located on the eastern border of the parcel would be the nearest residents at approximately 800 feet. Additionally, several other houses are located approximately 950 feet to the north and south of this site. At these close distances, significant additional noise mitigation would likely be required. While the Washington Road site would allow the sharing of the substation and switchyard with the Walnut peaking plant, because the power plants would be separated by a street and railroad tracks, sharing of some facilities (ammonia tank, fire system) would not be possible. This site would also require the installation of the diesel-fired fire pump, increasing the diesel particulates in the area and potential public health impacts. It would also not be possible to share staff because the new power plant will require staff 24 hours a day, while the Walnut Peaking Plant does not have onsite staff 24 hours a day/7 days a week.

The Morgan Road site was rejected because of its close proximity (just 300 feet) from an existing residential subdivision. While it is possible that the potential noise and visual impacts on these nearby receptions could be mitigated to a level of insignificance, this mitigation would add significant costs to the project in comparison to the A2PP site. This site would also require the installation of the diesel-fired fire pump, increasing the diesel particulates in the area and potential public health impacts. Additionally, the Morgan Road site does not offer the opportunity for sharing infrastructure and staff with existing TID generating facilities.

All three alternative sites would require the installation of new fire pumps, while the A2PP will be able to utilize the existing fire pump and fire protection system at the A2PP. Additionally, none of the three alternatives will satisfy the basic project objective of having the ability to share facilities and infrastructure with existing generating facilities: the anhydrous ammonia system, the 12,000-gallon storage tank and unloading facilities, the well water for service water and emergency shower/eyewash stations, the recycled water supply and wastewater discharge system, the process water system, the instrument and service air systems, the oil/water separator, the demineralized and reverse osmosis water storage tanks, and the administration building, including the control room and office space.

The A2PP site will result in the least potential environmental impacts compared to the Morgan Road, Washington Road, and Modesto WWTP sites. When compared to these alternatives, the A2PP site provides the best cost and least impact opportunity to fulfill the project objectives because the A2PP site is adjacent to an existing process water supply source from the Ceres WWTP, is located in an industrial area with large buildings that screen the site, and will be adjacent to an existing power plant, which offers the ability to share staff and facilities between the two plants including the existing emergency diesel fire pump.

Taken all together, the A2PP site best meets the project objectives without resulting in any adverse environmental impacts as compared to the Morgan Road, Washington Road, and Modesto WWTP sites. As a result, the Morgan Road, Washington Road, and Modesto WWTP sites were rejected in favor of the A2PP site. Table 6.4-4 provides a summary comparison of the A2PP and alternative sites, in light of the key project objectives and environmental factors.

**TABLE 6.4-4**
Comparison of the Proposed Site and Alternative Site Locations

| Characteristic | A2PP | Alternative 1 Modesto WWTP | Alternative 2 Washington Road | Alternative 3 Morgan Road |
|---|---|---|---|---|
| Location within TID's service territory | Yes | Yes | Yes | Yes |
| Ability to gain site control | Yes | Unknown | Unknown | Unknown |
| Availability of sufficient land area | Yes | Yes | Yes | Yes |
| Shared facilities and infrastructure with existing facilities | Yes | No | Partial | No |
| Proximity to existing transmission, distribution lines and an existing substation | 0.9 or 1.2 miles | 9 miles | Less than 0.1 mile (300 ft) | 3.2 miles |
| Distance to water supply source of appropriate quality and quantity | 0.5 mile | 1 mile | 2 miles | 1.5 miles |
| Land use consistent with City and County General Plans | Yes | With conditional use permit | With Rezone | With General Plan Amendment/Rezone |
| Proximity to nearest residence (ft) | 1,580 | 1,300 | 800 | 300 |
| Potential Presence of T&E Species & Habitat | Low | Moderate | Low | Low |

**TABLE 6.4-4**
Comparison of the Proposed Site and Alternative Site Locations

| Characteristic | A2PP | Alternative 1 Modesto WWTP | Alternative 2 Washington Road | Alternative 3 Morgan Road |
|---|---|---|---|---|
| Cultural/ Archaeological Sensitivity | Low | Moderate | Low | Low |
| Potential noise impacts | Low | Low | Moderate | High |
| Potential visual impacts | Low | Moderate | Low | Moderate |
| Potential soils impacts | Low (previously disturbed) | Moderate (lower quality farmland) | High (prime farmland) | Low (disturbed) |

# 6.5 Alternative Project Design Features

## 6.5.1 Alternative Linear Facilities

Linear facilities required for the A2PP include an electric transmission line and a natural gas supply line (Figure 1.1-3). A new water supply line is not needed as the A2PP will tie into the existing water treatment system at the existing Almond Power Plant. The A2PP will also not require any new sanitary sewer connection because there are no sanitary sewer facilities at the site. The proposed linear facilities are presented in Section 1.0, Executive Summary; Section 2.0, Project Description; Section 3.0, Electric Transmission; and Section 4.0, Natural Gas Supply. This section compares the alternative routes. The comparison is made among the following categories:

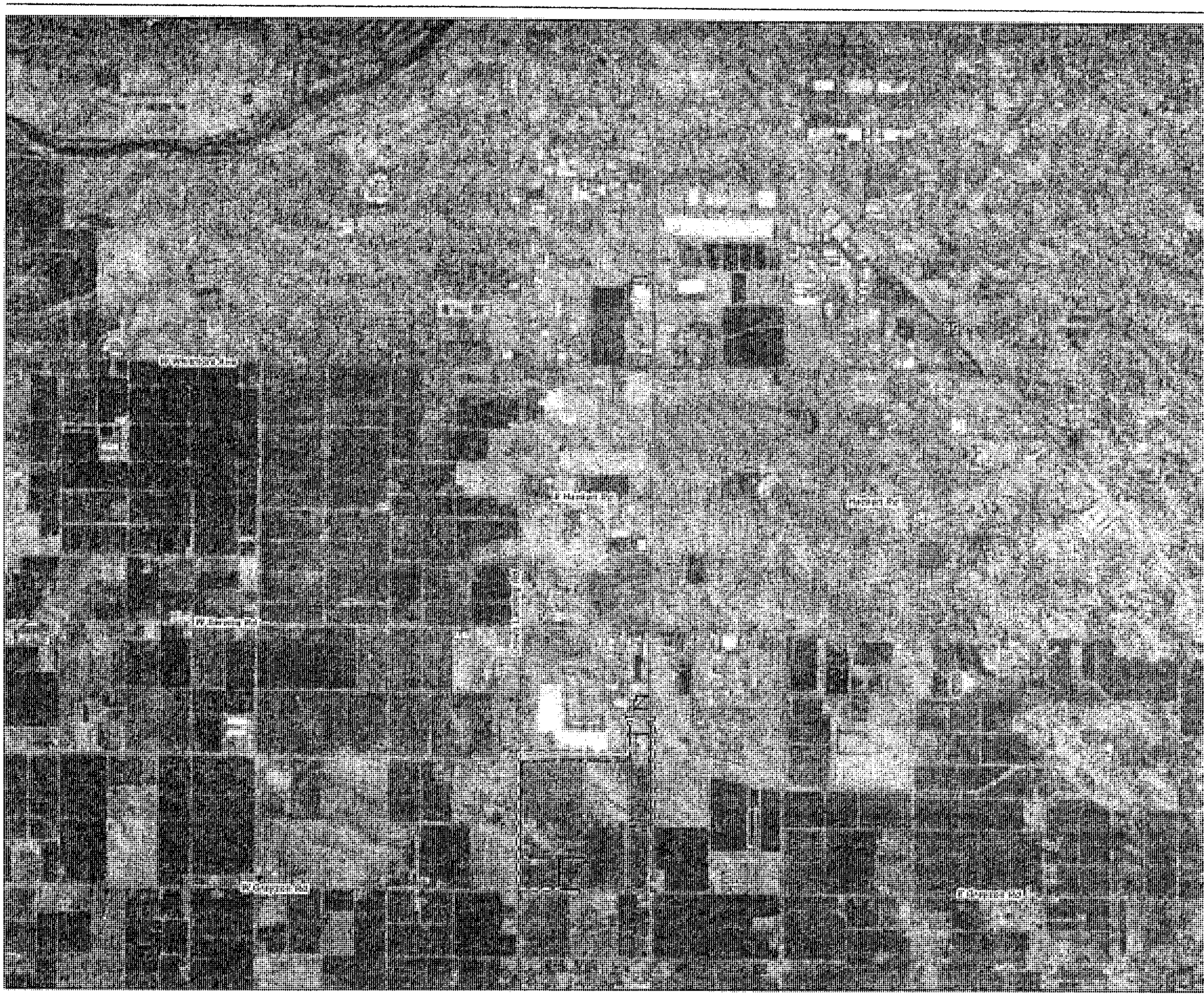
**Institutional Factors.** Institutional factors are an assessment of the ease of obtaining rights-of-way, public agency support, required permits, etc.

**Engineering/Construction Feasibility.** Engineering/construction feasibility is an assessment of how the linear facility can be physically placed along a given route.

**Environmental Factors.** Environmental factors are an initial assessment of which routes would have the least impact on the environment. Environmental impacts must be either not significant or less than significant with mitigation.

## 6.5.2 Electric Transmission Lines

Three alternative electrical transmission routes were evaluated in addition to the proposed route. Two of these routes appear feasible. The proposed and alternative routes that were considered are presented in Figure 6.5-1 and described below.



LEGEND
115-kV Circuit 1 Line (Corridor 1)
115-kV Circuit 2 Line (Corridor 2)
Reconductored 69kV Sub-Transmission Line
Alternate Route A
Alternate Route B
Alternate Route C
Proposed Grayson Substation
Laydown Area
Project Site

Note:
The Grayson Substation is being developed as a separate Project

N

0 1,000 2,000
Feet

**FIGURE 6.5-1**
**ALTERNATIVE LINEAR LOCATIONS**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

#### 6.5.2.1 Description of Routes

**Proposed Transmission Route** - When operational, the plant will have the capability of generating 174 megawatts with three LM6000PG combustion turbine generators. The proposed route includes the following two corridors and reconductoring of the 69-kV sub-transmission line.

- Corridor 1 - The proposed 115-kV route will exit the project site at the southwest corner, head south to the TID Lateral 2, cross over TID Lateral 2 then jog west briefly before continuing south along the shared property line of several private agricultural properties (Assessor Parcels 041-007-010, -005, -003) before terminating in to the proposed Grayson Substation. The total distance is approximately 0.9 mile.
- Corridor 2 - The proposed 115-kV route will exit the project site at the southwest corner and will extend south to the TID Lateral 2 then west to Crow's Landing Road then south to a private agricultural road and east into the proposed Grayson Substation. The total distance is approximately 1.2 miles.

**Alternative Transmission Routes.** Three separate alternative transmission line corridors Alternate Route A, B, and C were analyzed as alternatives to the proposed transmission routes.

- **Alternate Route A** - The proposed 115-kV route would exit the project on the southeast corner, and head south for 0.35 mile along the railroad tracks. The transmission line would then turn west along an agricultural road for 0.25 mile, and then south along a second agricultural road for 0.15 mile to the proposed Grayson Substation. The total route would be approximately 0.8 mile.
- **Alternate Route B** - The proposed 115-kV route would exit the project on the southeast corner, and head south for 0.6 mile, and turning west on Grayson Road for 0.3 mile to the proposed Grayson Substation. The total route would be approximately 0.9 mile.
- **Alternate Route C** - The proposed 115-kV route will exit the project site at the southwest corner for 0.2 mile, head west along the northern boundary of the TID Lateral 2 for 0.4 mile, and then head south on Crows Landing Road for 0.5 mile. At Grayson Road, the line would turn east for 0.5 mile to the proposed Grayson Substation. The total route would be approximately 1.6 miles.

#### 6.5.2.2 Institutional Factors

Alternate Routes B and C follow the alignment of railroads and public roads, where waterlines and other utility easements are relatively common and do not interfere with local uses. Corridor 1 and Alternate Route A, however, follow the alignment of non-public use agricultural roads, and would impact property owners and their farming activities. For Corridor 2, and Routes B and C, there are no indications of any institutional factors, rights-of-way, or land uses that would favor the routes.

#### 6.5.2.3 Engineering/Construction Feasibility

**Alternate Route A** - Alternate Route A is sited along a railroad track and non-public agricultural roads. Construction along the railroad track would be within an existing TID easement. Construction along the agricultural fields would be similar to those anticipated for the proposed Corridor 1.

**Alternate Route B** - Alternate Route B is sited along the railroad tracks and Grayson Road. Grayson Road from the railroad tracks heading east to the proposed Grayson Substation is impacted by existing easements and does not have adequate space for an additional 115-kV transmission line.

**Alternate Route** C - Alternate Route C is located along the TID Lateral 2, Crows Landing Road, and Grayson Road. There is potential during the short-term construction phase for traffic to be impacted, however these impacts are comparable to those for the proposed Corridor 2. Any construction-related impacts, such as ground disturbance or pavement damage, would be mitigated through restoration of the disturbed areas. Traffic control would be required for those portions of the alternative that follow roadways similar to the proposed Corridor 2. Traffic on most roads is light and limited to local travel.

#### 6.5.2.4 Environmental Factors

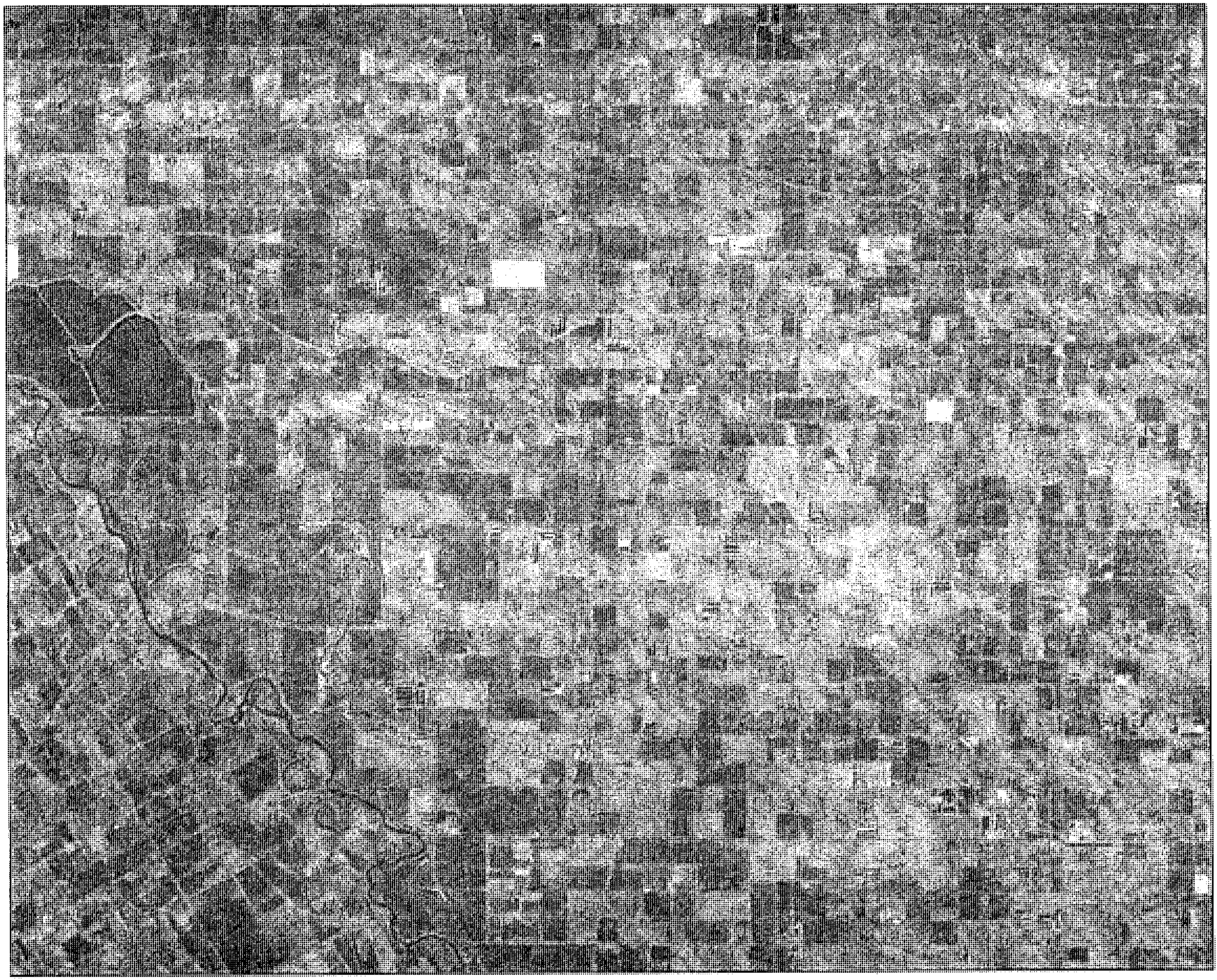
**Alternate Route A** - Alternate Route A is sited along a railroad track and non-public agricultural roads. Similar to Corridor 1, the portion of the line within the agricultural roads would impact land owners dependant on those roads to access their farmed fields. In addition, transmission poles located along these roads have the potential to remove small amounts of land from active farming (approximately 4 feet by 4 feet). Since there are orchards along this route, trees also need to be pruned regularly to avoid impacting the transmission lines.

**Alternate Route B** - Alternate Route B would be sited within a TID easement along the railroad tracks, and along a TID easement along Grayson Road. However, as discussed earlier, Grayson Road is impacted from the railroad tracks east to the proposed Grayson Substation and adequate space is not available for an additional 115-kV transmission line and associated transmission poles.

**Alternate Route** C - Alternate Route C is located along the TID irrigation canal and Crows Landing Road, and Grayson Road. The northeast intersection of Crows Landing Road and Grayson Road is currently an agricultural field; however, there are plans to develop this as a strip mall and gas station. The addition of a transmission line along this corridor could have undesirable visual impacts, and would not necessarily be conducive to the proposed activities on this corner.

### 6.5.3 Natural Gas Supply Lines

PG&E is currently determining the final alignment of the natural gas pipeline. Two possible alternatives have been evaluated for this AFC. Both routes appear feasible. A final determination on the alignment will be available in mid-2009. The two alternative routes are presented in Figure 6.5-2 and described below.



LEGEND

Natural Gas Pipeline (Alternate A)

Natural Gas Pipeline (Alternate B)

Project Site

N

0 2,500 5,000
Feet

**FIGURE 6.5-2**
**ALTERNATIVE GAS PIPELINE LOCATIONS**
ALMOND 2 POWER PLANT
*CERES, CALIFORNIA*

**CH2MHILL**

#### 6.5.3.1 Description of Routes

**Alternate A** - The proposed gas pipeline route is approximately 9.1 miles long. The pipeline would run west along the TID Lateral 2 and south on Crows Landing Road to Bradbury Road where it would connect with PG&E's Line #215.

Construction of the pipeline would require a 50-foot-wide temporary construction corridor. The specific location of the pipeline would be determined based on the avoidance of any sensitive environmental resources, ability to obtain ROW, and the location of existing pipelines. Open trench construction would be used for pipeline installation.

**Alternate B** - The alignment would extend west from the A2PP along the TID Lateral 2 to Carpenter Road. The route would then turn south and run along an easement on Carpenter Road to Bradbury Road where it would connect with PG&E's Line #215. The overall alignment length is approximately 11.1 miles.

#### 6.5.3.2 Environmental Factors

Each of the proposed natural gas pipeline routes would have similar impacts in most of the environmental areas because they will be buried, constructed using similar methods, are located near each other, cross similar habitat, and cross the same number of irrigation channels. The differences between routes, although minor, would likely exist in the areas described below. It should be noted that these differences are slight and construction of either alternative route would not likely result in significant adverse impacts.

**Air Quality.** Impacts would occur as a result of emissions from construction equipment. Since construction techniques would be similar, there would be a slight benefit from construction of Alternate A, which is shorter. Because Alternate B is longer, additional soil would be disturbed resulting in additional fugitive dust impacts and vehicle emissions.

**Biological Resources.** Gas pipelines would generally follow roads and rights-of-way (ROW) that are partly disturbed and would be buried upon completion of construction. No significant site-specific natural habitats or resources have been identified at this time. Small sites can be avoided if discovered through small changes within the 50-foot corridor.

**Cultural Resources.** Cultural resource sensitivity, which is low, would not differ throughout the area covered by the alternative routes.

**Public Health.** Public health is a largely a function of air quality and, therefore, would indicate the same preferences as air quality.

**Traffic and Transportation.** Traffic impacts are anticipated to be minor because traffic is similar along all of these roads. However, impacts on traffic would occur from construction along the edge or within the roadway because one lane would need to be closed in either case. Therefore, because impacts on traffic and transportation are greater the longer the corridor, Alternate A would have the lower impacts.

##### 6.5.3.2.1 Institutional Factors

Each of the gas pipeline alternatives follows the alignment of rural public roads where waterlines and other utility easements are relatively common and do not interfere with local uses. There are no indications of any institutional factors, rights-of-way, or land uses that would favor the routes. Therefore, the least-cost alternative, the proposed route, is favored.

#### 6.5.3.2.2 Engineering/Construction Feasibility

Each alternative would involve open-cut trenching techniques. The pipeline would cross rural roads, and there could be temporary interference with local transport; but the duration of construction and relatively low-level of traffic would not cause significant adverse environmental impacts. Restoration will likely be required for both routes because both follow county roadways; however, every effort will be made to locate the pipeline outside of the paved road section where existing road ROW is available. Traffic control will also be required for both routes. Alternative routes are available to all regional traffic. The least-cost alternative would favor the Alternate A route because it is shorter.

#### 6.5.3.3 Conclusion

Since there are no substantial differences in environmental impacts, institutional factors, and engineering/construction feasibility, either route is feasible and all impacts would be mitigated below the level of significance.

# 6.6 Technology Alternatives

## 6.6.1 Generation Technology Alternatives

Selection of the power generation technology focused on those technologies that can use the natural gas readily available from the existing gas transmission system. Because a primary purpose is to use the plant to provide operating reserves and thus reliability for TID's Balancing Authority requirements, renewable energy sources were not considered. The following is a discussion of the suitability of non-renewable energy technologies for application to the A2PP.

### 6.6.1.1 Conventional Boiler and Steam Turbine

This technology burns fuel in the furnace of a conventional boiler to create steam. The steam is used to drive a steam turbine-generator, and the steam is then condensed and returned to the boiler. This is a dated technology that is able to achieve thermal efficiencies up to approximately 36 percent when utilizing natural gas, although efficiencies are somewhat higher when utilizing oil or coal. Because of this low efficiency and large space requirement, the conventional boiler and steam turbine technology was eliminated from consideration.

### 6.6.1.2 Conventional Combined-cycle Combustion Turbine

This technology integrates combustion turbines and steam turbines to achieve higher efficiencies. The combustion turbine's hot exhaust is passed through a heat recovery system generator to create steam used to drive a steam turbine-generator. This technology is able to achieve high thermal efficiencies. The combined-cycle alternative, however, requires very large capital cost more appropriate for a baseload facility, a large site, and very large quantities of water for cooling. In addition, conventional combined-cycle technology cannot match the GE Energy LM 6000PG technology for rapid startup, efficient cycling, and high part-power efficiency and load following capability. These are essential characteristics for a peaking facility.

#### 6.6.1.3 Kalina Combined-cycle

This technology is similar to the conventional combined-cycle, except a mixture of ammonia and water is used in place of pure water in the steam cycle. The Kalina cycle could potentially increase combined-cycle thermal efficiencies by several percentage points. This technology is still in the development phase and has not been commercially demonstrated; therefore, it was eliminated from consideration.

#### 6.6.1.4 Internal Combustion Engines

Reciprocating internal combustion engine designs are also available for small peaking power plant configurations. These are based on the design for large marine diesel engines, fitted to burn natural gas. Advantages of internal combustion engines are that they: (1) use very little water for cooling, because they use a closed-loop coolant system with radiators and fans; (2) provide quick-start capability (on-line at full power in 10 minutes); and (3) are responsive to load-following needs because they are deployed in small units (for example, 10 to 14 engines in one power plant), that can be started up and shut down at will. Disadvantages of this design include higher emissions than comparable combustion turbine technology and potentially higher cost as numerous smaller-sized engines would be needed in larger capacity plants.

### 6.6.2 Fuel Technology Alternatives

Technologies based on fuels other than natural gas were eliminated from consideration because they do not meet the project objective of utilizing natural gas available from the existing transmission system. Some of these alternative fuels have potential for additional air quality and public health impacts. Others, like certain biofuels, are not available in commercial quantities or are not available via pipeline of other reliable delivery system. Additional factors rendering alternative fuel technologies unsuitable for the proposed project are as follows:

- No geothermal or no new hydroelectric resources of sufficient size and sufficient operational profile exist in the TID service territory or adjacent territories.
- Biomass fuels such as wood waste are not locally available in sufficient quantities to make them a practical alternative fuel and A2PP site space is limited.
- Solar and wind technologies are generally not dispatchable and are, therefore, not capable of providing fast-starting, flexible generating capacity and are not capable of producing ancillary services other than reactive power.
- Coal, fuel oil and similar technologies emit more air pollutants than technologies utilizing natural gas.
- The availability of the natural gas resource provided by PG&E, as well as the environmental and operational advantages of natural gas technologies, makes natural gas the logical choice for the proposed project.

### 6.6.3 $NO_x$ Control Alternatives

To minimize $NO_x$ emissions from the A2PP, the combustion turbine generators will be equipped with water injection combustors and selective catalytic reduction (SCR) using anhydrous ammonia as the reducing agent. The following combustion turbine $NO_x$ control alternatives were considered:

- Steam injection (capable of 25 to 42 parts per million [ppm] $NO_x$)
- Water injection (capable of 25 to 42 ppm $NO_x$)
- Dry low $NO_x$ combustors (capable of 15 to 25 ppm $NO_x$)

Water injection or dry low $NO_x$ were selected because these allow for lower acceptable $NO_x$ emissions while being able to achieve an output turndown rate of 30 percent. This turndown is necessary to meet variable load demand.

The following reducing agent alternatives were considered for use with the SCR system as alternatives to the existing anhydrous ammonia systems:

- Aqueous ammonia
- Urea

Anhydrous ammonia is used in many facilities for $NO_x$ control, but is more hazardous than diluted forms of ammonia; however, because the anhydrous ammonia tank will be shared between the A2PP and Almond Power Plant facility, aqueous ammonia use is not feasible. Urea has not been commercially demonstrated for long-term use with SCR and was eliminated from consideration.

# 6.7 References

Doud, Kristin. 2009. Personal communication between Kristin Doud, Planner for Stanislaus County, and Aarty Joshi of CH2M HILL. February.

# San Joaquin Valley
# Unified Air Pollution Control District

## TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

### I. TYPE OF PERMIT ACTION (Check appropriate box)

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

| | |
|---|---|
| COMPANY NAME: Turlock Irrigation District | FACILITY ID: N - 3299 |
| 1. Type of Organization: [ ] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [✓] Utility | |
| 2. Owner's Name: Turlock Irrigation District | |
| 3. Agent to the Owner: Randy Baysinger | |

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

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

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

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

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

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

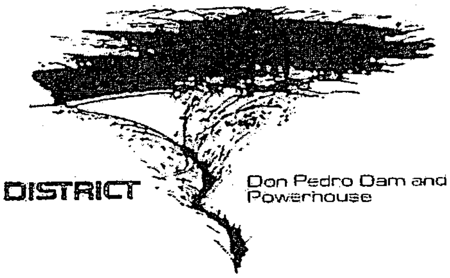
Randy Bg [signature]
Signature of Responsible Official

4-20-2009
Date

Randy Baysinger
Name of Responsible Official (please print)

Assistant General Manager, Power Supply
Title of Responsible Official (please print)

**TURLOCK IRRIGATION DISTRICT**
333 EAST CANAL DRIVE
POST OFFICE BOX 949
TURLOCK, CALIFORNIA 95381
(209) 883-8300


Don Pedro Dam and Powerhouse

September 15, 2009

Mr. Jagmeet Kahlon
San Joaquin Valley APCD
4800 Enterprise Way
Modesto, CA 95356-8718

Subject: Compliance Statement for the TID Almond 2 Power Plant Project

Dear Mr. Kahlon:

In accordance with Rule 2201, Section 4.15, "Additional Requirements for New Major Sources and Federal Major Modifications," Turlock Irrigation District (TID) is pleased to provide this compliance statement regarding its proposed Almond 2 Power Plant project.

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

- Almond Power Plant;
- Walnut Energy Center; and
- Walnut Power Plant.

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Please contact me if you have any questions regarding this certification.

Sincerely,

for Randy C. Baysinger
Assistant General Manager
Power Supply Administration
Turlock Irrigation District

cc: Jeffrey Adkins, Sierra Research
Sarah Madams, CH2M Hill
Susan Strachan, Strachan Consulting
Jeffery Harris, Ellison Schneider & Harris
Felicia Miller, CEC Project Manager

ATTACHMENT J
DISTRICT'S RESPONSE TO THE COMMENTS RECEIVED FROM THE APPLICANT ON THE PDOC ISSUED ON DECEMBER 3, 2009

## Response to the Comments from the Applicant

**Applicant's Comment #1:**

Page 1, Proposal: The fourth paragraph of this discussion states that "TID is expected to file applications to obtain ... PSD permits from EPA Region 9 for this project." This is not correct. TID evaluated PSD applicability in the application for a determination of compliance/authority to construct and determined that the proposed project is not subject to PSD review (Section 5.1.7.1.1 of the APC, pp. 5.1-52 through 54). A letter informing EPA of this determination was submitted to Region 9 on June 2, 2009; we made a formal request via email for concurrence with this determination on September 22, 2009. Please either remove this statement or revise it to indicate that TID has determined that the project is not required to obtain a PSD permit.

**District Response:**

The District has revised the document to state that "Per TID, the project is not required to obtain Prevention of Significant Deterioration (PSD) permit from the EPA."

**Applicant's Comment #2:**

Page 3, Equipment Listing and Draft Permit Conditions (Appendix A): The heat input rating for each CTG is shown in the equipment description as 523.2 MMBtu/hr. As discussed later in the analysis, the maximum rated heat input under cold temperature conditions is 554.9 MMBtu/hr while 523.2 MMBtu/hr is the nominal rating at average ambient temperature (60EF). To ensure that the description does not inadvertently limit the allowable heat input to the CTGs, we suggest showing the heat input rating as the permitted maximum heat input of 554.9 MMBtu/hr. This correction should also be made to the equipment description that appears at the beginning of each set of draft PDOC conditions.

**District Response:**

Each CTG is rated to deliver 54.2 MW under nominal ISO conditions, while operating at a heat input rate of 523.2 MMBtu/hr. Resetting heat input rate to 554.9 MMBtu/hr may not correspond to the turbine output of 54.2 MW. For this reason, the heat input rate has not been changed in the equipment description. To ensure that this heat input rate does not inadvertently become a limit, the District has decided to add "at nominal ISO MW rating" after the heat input rate in the equipment description of each permit.

**Applicant's Comment #3:**

Page 23 and Draft Condition 19 (Appendix At Emissions During the Commissioning Period: The draft condition correctly reflects the commissioning period emissions proposed in the application. However, the application neglected to mention that because turbine startups will occur during the commissioning period, the maximum hourly emissions during the commissioning period should not be lower than the startup emission limits. This affects only the hourly CO limit; we request that this hourly limit be changed from 29.36 lb/hr to 40.00 lb/hr. This will not create any new worst case hourly impacts as the new maximum hourly CO commissioning emissions limit will be the same as the maximum hourly CO startup emissions limit that has already been evaluated in the PDOC.

**District Response:**

The District agrees with the applicant and had reset the hourly limit of CO to 40.00 lb/hr for the commissioning period (Refer to condition #13 in Attachment A).

**BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA**
**1516 NINTH STREET, SACRAMENTO, CA 95814**
**1-800-822-6228 – WWW.ENERGY.CA.GOV**

**APPLICATION FOR CERTIFICATION FOR THE TID ALMOND 2 *POWER PLANT PROJECT***

**Docket No. 09-AFC-2**

***PROOF OF SERVICE***
**(Revised 2/8/10)**

**APPLICANT**
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e-recipient@caiso.com

**INTERVENORS**
California Unions for Reliable Energy ("CURE")
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Marc D. Joseph
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**Public Advisor**
**publicadviser@energy.state.ca.us**

*indicates change

## Declaration of Service

I, Mary Finn, declare that on Feburary 22, 2010, I served and filed copies of the attached, Notice of Final Determination of Compliance (FDOC) Facility: Turlock Irrigation District (09-AFC-02), dated, February 16, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/almond]**.

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

**(*Check all that Apply*)**

**FOR SERVICE TO ALL OTHER PARTIES:**

_____ sent electronically to all email addresses on the Proof of Service list;

__x__ by personal delivery or by depositing in the United States mail at Sacramento, CA with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

***AND***

**FOR FILING WITH THE ENERGY COMMISSION:**

_____ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

***OR***

__x__ depositing in the mail an original and 12 paper copies, as follows:

**CALIFORNIA ENERGY COMMISSION**
Attn: Docket No. 09-AFC-2
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

MF