Supplemental Filing

Air Quality and Public Health

Revised April 7, 2010

In support of the

Application for Certification

for

Oakley Generation Station Project

Oakley, California
(09-AFC-4)

Submitted to the:

California Energy Commission

Submitted by:

RADBACK ENERGY

With Technical Assistance by:

CH2MHILL
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Introduction

Attached a supplemental filing in support of the Contra Costa Generating Station, LLC Oakley Generating Station (OGS) project (09-AFC-04) Application for Certification (AFC). This filing represents a replacement of the Air Quality (Section 5.1) and Public Health (Section 5.9) sections as filed in the AFC on June 30, 2009. This supplement replaces and supersedes the original AFC sections and subsequent filings in response to CEC Staff Data Requests. This filing includes the two AFC sections and also revised appendixes for the air quality and public health analyses. Appendix 5.1C, however, is not included here. This appendix is the Prevention of Significant Deterioration (PSD) protocol. The protocol has not changed and is also not applicable to the OGS project because the OGS does not trigger PSD review.

ATTACHMENT A

Revised AFC Section 5.1, Air Quality

5.1 Air Quality

5.1.1 Introduction

This section presents the methodology and results of an analysis performed to assess potential effects of airborne emissions from the construction and routine operation of the Oakley Generating Station Project (OGS). Section 5.1.1 presents the introduction, applicant information, and the basic Bay Area Air Quality Management District (BAAQMD) rules applicable to the project. Section 5.1.2 presents the project description, both current and proposed. Section 5.1.3 presents data on the emissions of criteria and air toxic pollutants from the project. Section 5.1.4 discusses the Best Available Control Technology (BACT) evaluation for the project. Section 5.1.5 presents the air quality effects analysis for the project. Section 5.1.6 presents applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.7 presents agency contacts, and Section 5.1.8 presents permit requirements and schedules. Section 5.1.9 contains references cited or consulted in preparing this section.

Contra Costa Generating Station, LLC (Applicant) is proposing to construct and operate the Oakley Generating Station (OGS) which will be a nominally rated 624 MW, natural gas-fired combined cycle facility.

The project is planning to operate as a base loaded power plant and is proposed to operate up to approximately 8,463 hours per year, with an expected facility capacity factor at 60 to 80 percent. The project will consist of the following:

- Installation of two (2) nominally rated 213 megawatt (MW) GE 7FA combustion turbines with Dry Low NO_x (DLN) combustors and evaporative inlet air cooling.
- Installation of two (2) non-fired HRSGs coupled to a single GE D11 condensing steam turbine generator capable with a nominal rating of 218 MW.
- SCR and CO catalyst systems on both turbine/HRSG power trains.
- Installation of air cooled condenser to provide cooling and heat rejection from the power block process.
- Installation of an auxiliary boiler rated at 34,000 lbs steam/hr, firing natural gas. The boiler will provide auxiliary steam when the main power block is offline and during startups. The boiler will be equipped with ultralow NO_x burners and flue gas recirculation (FGR).
- Installation of all required auxiliary support systems.

The project design will incorporate the air pollution emission controls designed to meet BAAQMD BACT determinations. These controls will include DLN combustors in the CTG to limit nitrogen oxide (NO_x) production, selective catalytic reduction (SCR) with aqueous ammonia for additional NO_x reduction in the HRSG, an oxidation catalyst to control carbon monoxide (CO) and precursor organic compounds (POC) emissions. Fuel to be used will be pipeline specification natural gas**.** The auxiliary boiler will be equipped with ultra low NO_x burners and FGR.

5.1.2 Project Description

5.1.2.1 Current Site and Facilities

The project site is a 21.95-acre site located within the boundary of an existing 210-acre site owned by E. I. DuPont. CCGS, LLC holds an option to purchase the 21.95-acre site, and DuPont is currently proceeding with a lot line adjustment to separate the site from the larger 210-acre parcel. The project site is currently zoned "heavy industrial", with surrounding land uses comprised of industrial, vacant industrial, commercial, and agricultural. The site is located in the City of Oakley, Contra Costa County, California. The City of Oakley is presently revising its zoning regulations to match the 2020 General Plan. The site zoning will change from "heavy industrial" to "utility energy" land use, with the reminder of the DuPont site classified as "business park" or "light industrial".

The project site is bounded to the west by the Pacific Gas and Electric Company's (PG&E's) Antioch Terminal, a large natural gas transmission hub, to the north by DuPont property that is either industrial or vacant industrial, to the east by DuPont's titanium dioxide landfill area, and to the south by the Atchison, Topeka and Santa Fe railroad. Immediately south of the railroad is a large parcel currently in agriculture. A 74.6-acre commercial development, the Rivers Oaks Crossing, has been proposed for this parcel.

The site Universal Transverse Mercator (UTM) coordinates are as follows: 610,176.8 meters easting, 4,207,415 meters northing, Zone 10 (NAD27).

The project site elevation is approximately 20 feet above mean sea level (MSL). Because the site is located within the existing property boundary, the project site and surrounding areas are highly developed, and have been subject to disturbance for many years.

5.1.2.2 Project Equipment Specifications

The facility will consist of the following major equipment.

- Two 213 MW GE 7FA combustion turbines
- One 218 MW GE D11 steam turbine
- Two unfired HRSGs
- One auxiliary boiler
- One air-cooled condenser
- One evaporative fluid cooler
- One diesel powered fire pump

All power from the facility will be delivered to the California power grid under the control of the California Independent System Operator (CAISO).

The equipment specifications for the emissions sources are summarized in Table 5.1-1, Plant Specifications, as follows:

TABLE 5.1-1
Plant Specifications

Parameter	59 F/60 Percent Relative Humidity
Net Facility Output, MW*	624
CTG Heat Input, MMbtu/hr (LHV)*	1,896

TABLE 5.1-1
Plant Specifications

Parameter	59 F/60 Percent Relative Humidity
Net Facility Heat Rate, Btu/kWh (LHV)*	6,752

*Under ISO conditions.
Source: Radback-OGS Team, 2010.

Specifically, the emission sources will have the following characteristics.

5.1.2.2.1 Combustion Turbine

- Manufacturer: GE
- Model: 7FA
- Fuel: Pipeline quality natural gas
- Heat Input: ~2,150 MMBtu/hr (HHV) at 34°F
- Fuel consumption: up to ~2,103,718 standard cubic feet per hour
- Exhaust flow: ~1,161,633 actual cubic feet per minute at34 degrees Fahrenheit (°F) and 60 percent relative humidity
- Exhaust temperature: ~191 °F at the HRSG stack top exit

5.1.2.2.2 Heat Recovery Steam Generator

- Manufacturer: Not Selected
- Fuel: None
- Duct Burner Heat Input : No duct burners
- Steam Production Rating: 643 Klbs/hr (nominal)

5.1.2.2.3 Auxiliary Boiler

- Manufacturer: Not Selected
- Fuel: Pipeline quality natural gas
- Heat Input: 50.6 MMBtu/hr (HHV)
- Steam Production: 34,000 lb/hr

5.1.2.2.4 Evaporative Fluid Cooler

- Manufacturer: Marley or equivalent
- Number of Cells: 3
- Number of Fans: 3 (~190,600 actual cubic feet per minute each)
- Water circulation rate: 5,880 gallons per minute total
- Drift rate: 0.003 percent of circulating water flow (0.00003 fraction)
- Expected total dissolved solids (TDS): ~1,500 parts per million by weight (ppmw)

5.1.2.2.5 Fire Pump

- Manufacturer: Clarke model number JW6H-UFAD80
- Fuel: Ultra low sulfur diesel
- Horsepower: 400 BHP

Natural gas will be the only fuel used during plant operation with the exception of the fire pump which will fire ultra low sulfur diesel fuel. The typical natural gas composition is shown in Appendix 5.1A. Natural gas combustion results in the formation of NO_x, CO, precursor organic compounds (POCs), SO_2, PM_{10}, and $PM_{2.5}$. Because natural gas is a clean-burning fuel, there will be minimal formation of combustion PM_{10}, $PM_{2.5}$, and SO_2.

The fuel used on this project is similar to the fuels used on similar combined cycle power generation facilities. Table 5.1-2 presents a fuel use summary for the facility. Fuel use values are based on the maximum heat rating of each system, fuel specifications, and maximum operational scenario. Fuel analysis data for both natural gas and diesel fuel is presented in Appendix 5.1A.

TABLE 5.1-2
Estimated Fuel Use Summary for the Project

System	Fuel	Per Hour, mmscf	Per Day, mmscf	Per Year, mmscf
Combustion Turbine (each)	Natural gas	2.104	50.4489	17,317.65
Auxiliary Boiler	Natural Gas	0.0495	1.176	213.90
Fire Pump	Ultra Low Sulfur Diesel	18.7 gallons/hr	18.7 gallons/day	991.1 gallons/yr

*Natural gas heat rate of ~1022 Btu/scf
Auxiliary Boiler operation up to 24-hours per day, 4,324 hours per year.
Fire pump testing occurs 56 minutes per day, 53 testing events per year or 49 hours per year.
Source: Radback-OGS Team, 2010.

5.1.2.3 Climate and Meteorology

The overall climate in the project area is dominated by the semi-permanent eastern Pacific high pressure system, centered over the northeastern Pacific Ocean. This high is typically centered between the 140 W and 150 W meridians. Its position and size typically governs California's weather. In the summer, the high is strongest and moves to its northernmost position, which results in strong northwesterly air flow and negligible precipitation. A thermal low pressure area from the Sonoran-Mojave Desert also causes air to flow onshore over the San Francisco Bay area much of the summer.

The steady northwesterly flow around the eastern edge of the Pacific high pressure cell exerts a stress on the ocean surface along the west coast. This causes cold water to form at the surface, which cools the air even further. This cooling produces a high incidence of fog and clouds along the northern California coast in summer.

In the winter, the high weakens and moves southwestward toward Hawaii, which allows storms originating in the Gulf of Alaska to reach northern California, bringing wind and rain. About 80 percent of the region's annual rainfall of approximately 19.5 inches occurs between November and March. During the winter rainy periods, inversions are weak or nonexistent, winds are often moderate, and the air pollution potential is very low. During summer and fall, when the Pacific high becomes dominant, inversions become strong and often are surface based; winds are light and the pollution potential is high. These periods are often characterized by winds that flow out of the Central Valley into the Bay Area and often include Tule fog.

Historical climatic data for the project area was derived from the following sites located near the project site:

- BAAQMD
- National Weather Service
- National Climatic Data Center

Data for the Antioch Pump Plant (#040232) for the period 3-1-1955 through 12-31-2008 shows the following:

- Annual average maximum temperature = 73.3 ^{o}F
- Annual average minimum temperature = 48.0 ^{o}F
- Annual average total precipitation = 13.17 in.

Appendix 5.1B contains summary climate and meteorological data for the Antioch station. Annual and quarterly wind roses for the Contra Costa Power Plant (CCP) meteorological monitoring station for the five-year period prepared by BAAQMD for 2001-02 and 2004-07 are also presented in Appendix 5.1B. The annual wind rose data indicates that a majority of the regional wind flow is from the west through northwest, with periods of calm winds experienced approximately 8.48% of the time.

5.1.3 Emissions Evaluation

5.1.3.1 Facility Emissions

Installation and operation of the project will result in the emissions signature for the site that will be less than 100 tpy for all criteria pollutants, and as such the project will be considered a major NSR source for NO_x under the BAAQMD rules. The project will not trigger the requirements of the Federal Prevention of Significant Deterioration (PSD) program since the emissions of one or more criteria pollutants will not exceed either the 100 tpy major source applicability thresholds. The applicability determination for PSD is based on both the commissioning year and post commissioning year emissions. Thus, none of the proposed operational profile years will exceed the PSD applicability thresholds. Criteria pollutant emissions from the new combustion turbines/HRSGs and auxiliary equipment are delineated in the following sections, while emissions of hazardous air pollutants are delineated in Section 5.9. Backup data for both the criteria and hazardous air pollutant emission calculations are provided in Appendix 5.1A.

The hourly, daily and annual emissions for all criteria pollutants are based upon worst-case assumptions for each pollutant. The intent was to envelope the project emissions based upon the three (3) dispatch profiles provided in Appendix 5.1A. The daily operation always assumes 24 hours of operation with at least one cold or warm/hot start and one shutdown. The worst-case annual emissions profiles will be dependent upon pollutant and which worst-case dispatch assumption produces the maximum annual potential to emit. Thus, the following assumptions will apply to the proposed project:

- For the highest annual emissions of NO_x, SO_2, and PM10/2.5, up to 8,424 hours of operation at base load, up to 51 hot starts, one (1) cold start, and up to 52 shutdowns per year for a total of 8,463 hours per year with up to 24 hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 403 hours per year. This is identified on the attached spreadsheet in Appendix 5.1-A as Annual Emissions 3.

- For the highest annual emissions of POC, up to 5,433 hours at base load with up to 260 hot starts, 51 warm starts, one (1) cold start, and up to 312 shutdowns for a total of 5,662 hours per year with up to 24-hour per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 3,992 hours per year. This is identified in Appendix 5.1-A as Annual Emissions 2.
- For the highest annual emissions of CO, up to 5,157 hours per year of base load operation, up to 275 hot starts, 25 cold starts, and up to 300 shutdowns per year for a total of 5,390 hours per year with up to 24-hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,324 hours per year. This is identified in Appendix 5.1-A as Annual Emissions 1.
- All three emissions scenarios include 1,500 hours per year for the evaporative fluid cooler with up to 24 hours per day of operation, and 49 hours per year for fire pump testing.

The BAAQMD has proposed $PM_{2.5}$ significance thresholds at 1.2 µg/m^3 for 24-hour averages and 0.3 µg/m^3 for annual averages. The existing background 24-hour $PM_{2.5}$ monitoring data from Concord already equals the Federal standard but does not exceed the annual standard. The BAAQMD has been formally re-designated as a Federal non-attainment area for $PM_{2.5}$.

During the first year of operation, plant commissioning activities, which is planned to occur over an estimated 831operating hours during the first year of operation, will have higher hourly and daily emission profiles than during normal operations in the subsequent years of operation. The emissions during the first year of operation are presented below and were included in the air quality modeling analysis along with subsequent post commissioning yearly emissions.

The proposed project will be a major NSR source as defined by the air district's siting regulations for NO_x and will be subject to District requirements for emission offsets and air quality modeling analyses for criteria pollutants and toxics. The applicant has prepared an air quality emissions and impact analysis to comply with the BAAQMD and the California Energy Commission (CEC) regulations. The modeling analysis includes impact evaluations for those pollutants shown in Table 5.1-3 and the CEC requirements for evaluation of project air quality impacts. The emissions presented in Table 5.1-3 are the worst-case potential emissions on an annual basis.

Per Table 5.1-3, the project will result in emissions that will not exceed the EPA/BAAQMD PSD major source thresholds for any pollutant. Additionally, NO_x emissions from the proposed project will exceed the BAAQMD thresholds defining a major source for purposes of New Source Review (NSR), and emissions will exceed the EPA/BAAQMD major source thresholds of 10 tons per year for a single HAP and 25 tons per year for all HAPs. The project triggers the BAAQMD offset requirements for NO_x only. Air quality and toxics impacts analyses are required as part of the major source permit application. Modeled ambient impacts are below the levels at which preconstruction monitoring is required.

The emissions calculations presented in the application represent the highest potential emissions. As stated previously, the turbines will be the General Electric Model 7FA, each equipped with dry low NO_x combustors. Each turbine will incorporate General Electric's

Rapid Response capability with cold, warm, and hot starts taking shorter time to achieve compliance with normal steady state emission limits than conventional start-ups. Each turbine will also include an unfired HRSG. During periods of plant shutdown, a 50.6 MMBtu/hr auxiliary boiler will be utilized to maintain the plant in a hot-standby condition.

TABLE 5.1-3
Significant Emissions Threshold Summary

Pollutant	Cumulative Increase, tpy	Federal/State Attainment		Federal and BAAQMD Major Source Thresholds PSD/NNSR, tpy		Significant Emissions Rate, tpy	Major Source (PSD/NSR)	Significant Emissions Increase
NO_x	98.8	Y	Y	100	40	40	NSR	N
SO_2	12.6	Y	Y	100	100	40	No	N
CO	98.8	Y	Y	100	100	100	No	N
PM10	76.3	Y	N	100	100	15	No	N
PM2.5	76.3	N	N	100	100	15	No	N
POC (O_3 Precursor)	29.5	N	N	100	40	40	NoSR	N

5.1.3.2 Normal Operations

Operation of the proposed process and equipment systems will result in emissions to the atmosphere of both criteria and toxic air pollutants. Criteria pollutant emissions will consist primarily of NO_x, CO, POCs, sulfur oxides (SO_x), total suspended particulates (TSP), PM_{10}, and $PM_{2.5}$. Air toxic pollutants will consist of a combination of toxic gases and toxic PM species. Table 5.1-4, lists the pollutants that may potentially be emitted from the project.

TABLE 5.1-4
Chemical Substances Potentially Emitted to the Air from the Project

Criteria Pollutants

Particulate Matter
Carbon Monoxide
Sulfur Oxides
Nitrogen Oxides
Volatile Organic Compounds
Lead

Noncriteria Pollutants (Toxic Pollutants)

Ammonia
Polycyclic Aromatic Hydrocarbons (PAHs)
Acetaldehyde
Acrolein
Benzene
1-3 Butadiene
Ethylbenzene
Formaldehyde
Hexane (n-Hexane)
Xylene
Arsenic
Aluminum
Cadmium
Chromium VI
Copper
Iron
Mercury
Manganese

TABLE 5.1-4
Chemical Substances Potentially Emitted to the Air from the Project

Naphthalene
Propylene
Propylene Oxide
Toluene
Nickel
Silver
Zinc
Diesel PM

5.1.3.3 Criteria Pollutant Emissions

Tables 5.1-5 through 5.1-8 present data on the criteria pollutant emissions expected from the facility equipment and systems under normal operating scenarios. The maximum hourly emissions are based on Case 01C (34°F day at base load operation) or are based on cold start maximum hourly emission rates. A cold start is defined as a one hour event with the turbine/HRSG stack emissions in BACT compliance at the end of the first hour. The worst case day for emissions is defined at one cold start (45 minutes of start plus 15 minutes of base load), one shutdown (30 minutes of shutdown plus 30 minutes of base load), and 22 hours of base load operation (Case 01F stack parameters at 80 percent load and Case 01C base load emissions). Three operational profiles were examined for this application and are summarized in Appendix 5.1A. The differences between the three operational profiles are based on annual run time hours and the total annual startup/shutdown events. For NO_x, PM, and SO_x, the maximum potential to emit are based on a profile having 8,463 hours of operation with one cold start 51 warm/hot starts and 52 shutdowns. For CO, the worst-case emissions are based on a profile having 5,390 hours of operation with 25 cold starts and 275 warm/hot starts and 300 shutdowns. The worst-case POC emissions are based on 5,662 hours of operation with one (1) cold start, 260 hot starts, 51 warm starts and 312 shutdowns. Thus, for each pollutant, the maximum potential to emit is presented in Appendix 5.1A and in the tables below.

In addition, the facility may need periodic combustor tuning. This is a regular plant equipment maintenance procedure in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the equipment manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The routine tuning operations are not expected to exceed sixteen (16) hours per year per turbine or 8 hours per event per turbine. The tuning emissions are listed in Table 5.1-6.

TABLE 5.1-5
Combustion Turbine/HRSG and Aux Boiler Emissions for the Project (Steady State Operation-Controlled Per Turbine Non Commissioning Year)

Pollutant	Emission Factor and Units	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)*
NO_x	2.0 ppmvd[a]	15.52	372.48	49.3
CO	2.0 ppmvd[a]	9.45	226.8	49.0
POC	1.0 ppmvd	2.71	65.04	14.6
SO_x	<=0.00281 lbs/MMBtu	6.00	144.0	6.3
$PM_{10/2.5}$	9.0 lb/hr	9.0	216.0	38.1
NH_3	5.0 ppmvd	14.36	344.64	60.66
Auxiliary Boiler at 4,324 hours per year				
NO_x	7.0 ppmvd	0.42	10.08	0.92

TABLE 5.1-5
Combustion Turbine/HRSG and Aux Boiler Emissions for the Project (Steady State Operation-Controlled Per Turbine Non Commissioning Year)

Pollutant	Emission Factor and Units	Max Hour Emissions (lbs)	Max Daily Emissions (lbs)	Max Annual Emissions (tons)*
CO	10.0 ppmvd	0.37	8.88	0.79
POC	5.0 ppmvd	0.11	2.54	0.24
SO_x	0.00276 lbs/MMBtu	0.14	3.38	0.30
$PM_{10/2.5}$	0.007 lbs/MMBtu	0.35	8.50	0.77

*Annual Emissions assume startup/shutdown operation

[a] Annual NO_x emissions are based on 1.5 ppmvd and annual CO based on 1.0 ppmvd. Annual SO_x is based on 0.25 gr/100 scf (1.5 lb/hr) while short term is based on 1.0 gr/100scf (6 lb/hr). All annual emissions assume annual operational profile with startup/shutdowns.
Note: Auxiliary boiler operates up to 24 hours per day when turbines are not operational and up to 2 overlapping hours per day during turbine operation.

Source: Radback-OGS Team, 2010.

TABLE 5.1-6
Startup and Shutdown Emissions Per Turbine

Parameter/Mode	Cold Startup/Tuning[a]	Hot/Warm Startup	Shutdown
NO_x, lbs/event	96.0/768.0	22.0	39.0
CO, lbs/event	360.0/2,880.0	85.0	140.0
POC, lbs/event	67.0/536.0	31.0	17.0
PM_{10}, lbs/event	6.8/54.4	2.1	4.5
SO_x, lbs/event	2.9/23.2	0.9	1.9
Event Time, minutes[b]	90 minutes	30 minutes	60 minutes
Maximum Number of Events/Year	25 (Annual Case 1)	312 (Annual Case 2)	312 (Annual Case 2)

Source: Radback-OGS Team, 2010.

[a] Combustor tuning (per turbine) not to exceed 16 hours per year, 8 hours per event.

[b] The startup time presented represents expected worst-case. Actual startup event times may be less..

TABLE 5.1-7
Each Combustion Turbine/HRSG Emissions for the Project (Including Base Load Cold, Hot/Warm Startup and Shutdown, Whichever is Greater) for the Non-Commissioning Year

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
NO_x	N/A	99.88	488.12	49.3
CO	N/A	362.36	715.00	49.0
POCs	N/A	67.68	145.57	14.6
SO_x	N/A	6.0	144.0	6.3*

TABLE 5.1-7
Each Combustion Turbine/HRSG Emissions for the Project (Including Base Load Cold, Hot/Warm Startup and Shutdown, Whichever is Greater) for the Non-Commissioning Year

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
$PM_{10/2.5}$	N/A	9.0	216.0	38.1

Annual average SO_x is based on annual average grain loading of 0.25 gr/scf and 1.5 lb/hr emission rate
Source: Radback-OGS Team, 2010.

TABLE 5.1-8
Evaporative Fluid Cooler and Fire Pump Engine Emissions for the Project

Pollutant	TDS (mg/L)	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
Evaporative Fluid Cooler				
$PM_{10/2.5}$	1,500	0.132	3.17	0.099
Pollutant	**g/hp-hr**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
Fire Pump Engine				
NO_x	2.61	2.148	2.148	0.0569
CO	0.84	0.691	0.691	0.0183
POC	0.10	0.086	0.086	0.0023
SO_x	0.0015% by weight	0.004	0.004	0.0001
$PM_{10/2.5}$	0.10	0.085	0.085	0.0022

Notes: Evaporative fluid cooler operates up to 24 hours per day and up to 1,500 hours per year.
Fire pump operates 56 minutes per test, 49 hours per year.

Source: Radback-OGS Team, 2010.

Table 5.1-9 presents a summary of the total proposed facility operational emissions, including commissioning emissions. During the first year of operation, plant commissioning activities, which is planned to occur over an estimated 2,556 hours, will have higher hourly and daily emission profiles for up to 831 hours than during normal operations in the subsequent years of operation. For commissioning, the worst-case hour assumed one turbine in cold start with the other turbine undergoing commissioning activities based on the activity that produced the highest emission rate. The worst-case day assumed one turbine in commissioning for 24-hours with the other turbine undergoing the non-commissioning activity that produced the maximum 24-hour emission rate.

TABLE 5.1-9
Summary of Total Facility Emissions for the Project

Pollutant	**pounds/hour** ***(commissioning hour)***	**pounds/day*** ***(commissioning day)****	**tons/year** ***(commissioning year)***
NO$_x$[1]	200.19	979.24	98.8
	(249.00)	*(2,869.77)*	*(98.8)*
CO[2]	725.09	1,431.43	98.8
	(1,062.73)	*(11,520.54)*	*(98.8)*
POCs[3]	135.46	291.44	29.5
	(105.96)	*(1,055.38)*	*(29.5)*
SO$_x$[1]	12.14	288.57	12.6
	(12.14)	*(288.57)*	*(12.6)*
TSP[1]	18.49	*436.68*	76.3
	(18.49)	*(436.68)*	*(76.3)*
PM10/2.5[1]	18.49	*436.68*	76.3
	(18.49)	*(436.68)*	*(76.3)*
NH$_3$[1]	28.84	689.74	117.72

Normal Operation Assumptions:

[1] Annual NO$_x$, PM, and SO$_x$ based on 8,463 hours per year of operation from the turbines (1 cold start and 51 hot starts), 403 hours for the auxiliary boiler, and 1,500 hours per year for the evaporative condenser. Annual SO$_x$ emissions based on annual average grain loading and 1.5 lb/hr.

[2] Annual CO is based on 5,390 hours of operation with 25 cold starts and 275 warm/hot starts with the auxiliary boiler at 4,324 hours per year.

[3] POC based on 5,662 hours of operation with one cold start and 311 warm/hot starts.

* Daily emissions assume 24 hours per day operation for the turbines and 2 hours per day for the auxiliary boiler. Plant wide annual boiler emissions based on annual worst case assumption per pollutant as noted. Worst case commissioning day assumed 24-hours of no load operation for one turbine with the other turbine already commissioned and operating with worst-case operating day assumptions.

Worst case hourly assumes that the fire pump is not tested during turbine startup.

Hourly commissioning assumes 1-hour of auxiliary boiler operation and daily commissioning assumes 2 hours of auxiliary boiler operation.

Commissioning expected to occur over a four (4) month period.

Source: Radback-OGS Team, 2010.

5.1.3.3.1 Greenhouse Gas Emissions

Climate Change and Global Warming

Climate change refers to any significant change in measures of climate, such as average temperature, precipitation, or wind patterns over a period of time. Climate change may result from natural factors, natural processes, and human activities that change the composition of the atmosphere and alter the surface and features of the land. Significant changes in global climate patterns have recently been associated with global warming, an average increase in the temperature of the atmosphere near the Earth's surface, attributed to accumulation of GHG emissions in the atmosphere. GHGs trap heat in the atmosphere, which in turn heats the surface of the Earth.

Some GHGs occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The emission of

GHGs through the combustion of fossil fuels (i.e., fuels containing carbon) in conjunction with other human activities, appears to be closely associated with global warming.

State law defines GHG to include the following: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) (Health and Safety Code §38505(g)). The most common GHG that results from human activity is CO2, followed by CH4 and N2O.

Legislative Action

Assembly Bill (AB) 1493 (June 2002)

On July 22, 2002, Governor Gray Davis of California signed into law Assembly Bill (AB) 1493, a statute directing the California Air Resources Board (CARB) to "develop and adopt regulations that achieve the maximum feasible and cost-effective reduction of GHG emissions from motor vehicles." The statute required CARB to develop and adopt the regulations no later than January 1, 2005. AB 1493 allows credits for reductions in GHG emissions occurring before CARB's regulations become final (i.e., an early reduction credit). AB 1493 also required that no later than July 1, 2003, the California Climate Action Registry, in consultation with the CARB, shall adopt procedures for the reporting of reductions in GHG emissions from mobile sources.

Executive Order S-3-05 (June 2005)

On June 1, 2005, Governor Arnold Schwarzenegger announced GHG emission reduction targets for California. The governor signed Executive Order S-3-05 which established GHG emission reduction targets and charged the secretary of the California Environmental Protection Agency (CalEPA) with the coordination of the oversight of efforts to achieve them. The Executive Order establishes three targets for reducing global warming pollution:

- Reduce GHG emissions to 2000 emission levels by 2010;
- Reduce GHG emissions to 1990 emission levels by 2020; and,
- Reduce GHG emissions to 80 percent below 1990 levels by 2050.

"Global Warming Solutions Act of 2006" (AB 32)

The Global Warming Solutions Act of 2006 (AB32) was signed into law on September 27, 2006. AB32 does not "limit or expand" existing authority of districts. Specifically, AB32 requires CARB to:

- Establish a statewide greenhouse gas emissions cap for 2020, based on 1990 emissions by January 1, 2008;
- Adopt mandatory reporting rules for significant sources of greenhouse gases by January 1, 2009;
- Adopt a plan by January 1, 2009, that indicates how emission reductions will be achieved from significant greenhouse gas sources via regulations, market mechanisms and other actions;

- Adopt regulations by January 1, 2011, that will achieve the maximum technologically feasible and cost-effective reductions in greenhouse gases, including provisions for using both market mechanisms and alternative compliance mechanisms;
- Convene an Environmental Justice Advisory Committee and an Economic and Technology Advancement Advisory Committee to advise CARB;
- Ensure public notice and opportunity for comment for all CARB actions;
- Adopt rules for "sources" of greenhouse gases, including non-vehicular sources; and
- Prior to imposing any mandates or authorizing market mechanisms, evaluate several factors, including but not limited to impacts on California's economy, the environment and public health, equity between regulated entities; electricity reliability, and conformance with other environmental laws, and ensure that the rules do not disproportionately impact low-income communities.

Consistent with the requirement to develop a Scoping Plan indicating how GHG emission reductions will be achieved through regulations, market mechanisms, and other actions, the Proposed Scoping Plan was released for public review and comment in October 2008. The Proposed Scoping Plan calls for reducing greenhouse gas emissions to 1990 levels by 2020. This means cutting approximately 30 percent from business-as-usual (BAU) emission levels projected for 2020, or about 15 percent from today's levels. Key elements of CARB staff's recommendations for reducing California's greenhouse gas emissions to 1990 levels by 2020 contained in the Proposed Scoping Plan include the following:

- Expansion and strengthening of existing energy efficiency programs and building and appliance standards;
- Expansion of the Renewables Portfolio Standard to 33 percent;
- Development of a California cap-and-trade program that links with other Western Climate Initiative (WCI) Partner programs to create a regional market system;
- Establishing targets for transportation-related greenhouse gases and pursuing policies and incentives to achieve those targets;
- Adoption and implementation of existing State laws and policies, including California's clean car standards goods movement measures, and the Low Carbon Fuel Standard; and
- Targeted fees, including a public good charge on water use, fees on high GWP gases and a fee to fund the State's long-term commitment to AB 32 administration.

Senate Bill (SB) 97 (August 2007)

In August 2007, Governor Schwarzenegger signed into law Senate Bill (SB) 97 – CEQA: Greenhouse Gas Emissions stating, "This bill advances a coordinated policy for reducing greenhouse gas emissions by directing the Office of Planning and Research (OPR) and the Resources Agency to develop CEQA guidelines on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions." Specifically, SB 97 requires OPR, by July 1, 2009, to prepare, develop, and transmit guidelines to the Resources Agency for the feasible mitigation of greenhouse gas emissions or the effects of greenhouse gas emissions, as required by CEQA, including, but not limited to, effects associated with transportation or energy consumption. The Resources Agency would be required to certify and adopt those guidelines by January 1, 2010. The OPR would be required to periodically update the guidelines to incorporate new information or criteria established by the CARB pursuant to the California Global Warming Solutions Act of 2006. SB 97 also identifies a limited number of types of projects that would be exempt under CEQA from analyzing GHG emissions. Finally, SB 97 will be repealed on January 1, 2010.

Consistent with SB 97, on June 19, 2008, OPR released its "Technical Advisory on CEQA and Climate Change," which was developed in cooperation with the Resources Agency, the California Environmental Protection Agency (Cal/EPA), and the California Air Resources Board (CARB). According to OPR, the "Technical Advisory" offers the informal interim guidance regarding the steps lead agencies should take to address climate change in their CEQA documents, until CEQA guidelines are developed pursuant to SB 97 on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions.

According to OPR, lead agencies should determine whether greenhouse gases may be generated by a proposed project, and if so, quantify or estimate the GHG emissions by type and source. Second, the lead agency must assess whether those emissions are individually or cumulatively significant. When assessing whether a project's effects on climate change are "cumulatively considerable" even though it's GHG contribution may be individually limited, the lead agency must consider the impact of the project when viewed in connection with the effects of past, current, and probable future projects. Finally, if the lead agency determines that the GHG emissions from the project as proposed are potentially significant, it must investigate and implement ways to avoid, reduce, or otherwise mitigate the impacts of those emissions.

Greenhouse Gas Impacts and CEQA

General scientific consensus and increasing public awareness regarding global warming and climate change have placed new focus on the CEQA review process as a means to address the effects of GHG emissions from proposed projects on climate change. Public agencies are striving to determine the appropriate means by which to evaluate and mitigate the impacts of proposed projects on climate change. Subsequent to the adoption of AB 32, the California Attorney General's Office determined that GHG emissions contributing to global climate change contribute to potential adverse environmental impacts that should be evaluated pursuant to the CEQA. The Attorney General's Office has submitted numerous comment letters to lead agencies on their CEQA documents for failure to analyze GHG emissions, failure to make a significance determination, and failure to implement feasible mitigation measures to reduce GHG emissions to the maximum extent feasible (SCAQMD, 2008).

Project GHG Estimates

GHG emissions have been estimated for both the construction and operation phases of the project.

Construction emissions are presented in Appendix 5.1E and include emission evaluations for the following source types:

- On and offsite construction equipment exhaust,

- Construction site delivery vehicle exhaust emissions (including railroad emissions),
- Construction site support vehicle exhaust emissions, and,
- Construction worker travel exhaust emissions.

Operational emissions of greenhouse gases (GHG) will be primarily from the combustion of fuels in the turbine, auxiliary boiler, and the fire pump along with SF6 emissions from the circuit breakers. Appendix 5.1A, contains the support data for the GHG emissions evaluation. Estimated carbon dioxide equivalents (CO_2e) emissions for the project operational phase, based on ISO conditions, are as follows:

CO_2e = 1,932,480.1 tons/year

The emission factors and calculation methods are based on the California Climate Action Registry General Protocol, January 2009, BAAQMD guidance, and CARB GHG Reporting Guidelines-2009. Additionally, a GHG control technology analysis is presented in Appendix 5.1F.

5.1.3.3.2 NSR Facility Status

BAAQMD regulations 2-2-215, 302 and 303 require OGS to provide emission offsets (emissions reduction credits, or ERCs) when emissions exceed specified levels on a pollutant-specific basis. Section 2-2-302 requires POC and NO_x emission reduction credits to be provided at an offset ratio of 1:1 or 1.15:1 dependent upon emissions levels. Because both POC and NO_x contribute to the Bay Area Basin ozone levels, Section 2-2-302.2 allows emission reduction credits of POC's to be used to offset increased emissions of NO_x, at the required offset ratios as stated above. Section 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tpy of SO_2 and $PM_{10/2.5}$. As facility emissions of SO_2 and $PM_{10/2.5}$ will be below 100 tpy, these pollutants will not need to be offset based upon BAAQMD rules.

Currently, the BAAQMD air basin is attainment/unclassified for nitrogen dioxide (NO_2), sulfur dioxide (SO_2), PM_{10}, and CO, and is non-attainment for $PM_{2.5}$ and ozone. Detailed emissions data on the facility are presented in Appendix 5.1A. Based upon the annual emissions presented in Table 5.1-9, the facility will not trigger the PSD program requirements for any attainment pollutant, including NO_x, CO, and PM10/2.5. Therefore, a PSD increment analysis and a Class I effects assessment will not be required (see Appendix 5.1C). The proposed criteria pollutant mitigation strategy for the project is discussed in Appendix 5.1G, , and is summarized below.

- NO_x and POC mitigation will be provided in the form of Emission Reduction Credits (ERCs) to satisfy BAAQMD Regulations 2-2-215, 302 and 303.
- $PM_{10/2.5}$ and SO_2 mitigation will be achieved by developing CEQA based mitigation programs, such as fireplace replacement, street sweeping, or funding the Carl Moyer program. These approaches will be discussed with the CEC staff.
- CO offsets are not required since the air basin is in attainment.

5.1.3.4 Hazardous Air Pollutants

See Section 5.9, Public Health, for a detailed discussion and quantification of HAP emissions from the project and the results of the health risk assessment. See Appendix 5.1D for the public health analysis health risk assessment (HRA) support materials. Sections 5.5 and 5.9 also discuss the need for Risk Management Plans pursuant to 40 CFR 68 and the California Accidental Release Program regulations.

5.1.3.5 Construction

Construction-related emissions are based on the following:

- Construction of the facility is expected to result in the temporary disturbance of approximately 20 acres. A 20-acre construction laydown and parking area will also be used for materials storage and craft labor parking.
- Moderate site preparation will be required prior to construction of the turbine/HRSGs, auxiliary boiler, fire pump, evaporative fluid cooler, building foundations, support structures, etc.
- Construction activity is expected to last for a total of 33 months.

Construction-related issues and emissions at the project site are consistent with issues and emissions encountered at any construction site. Compliance with the provisions of the following permits will generally result in minimal site emissions: (1) grading permit, (2) Stormwater Pollution Prevention Plan (SWPPP) requirements (construction site provisions), (3) use permit, (4) building permits, and (5) the BAAQMD Permit to Construct (PTC), which will require compliance with the provisions of all applicable fugitive dust rules that pertain to the site construction phase. An analysis of construction site emissions is presented in Appendix 5.1E, . This analysis incorporates the following mitigation measures or control strategies:

- The Applicant will have an on-site construction mitigation manager who will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the proposed construction mitigations will be provided on a periodic basis.
- All unpaved roads and disturbed areas in the project and construction laydown and parking area will be watered as frequently as necessary to control fugitive dust. The frequency of watering will be on a minimum schedule of every 2.5 hours during the daily construction activity period. Watering may be reduced or eliminated during periods of precipitation.
- On-site vehicle speeds will be limited to 5 mph on unpaved areas within the project site construction site.
- The construction site entrance will be posted with visible speed limit signs.
- All construction equipment vehicle tires will be inspected and cleaned as necessary to be free of dirt prior to leaving the construction site via paved roadways.
- Gravel ramps will be provided at the tire cleaning area.

- All unpaved exits from the construction site will be graveled or treated to reduce track-out to public roadways.
- All construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been provided.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other similar measures as specified in the construction SWPPP to prevent runoff to roadways.
- All paved roads within the construction site will be cleaned on a periodic basis (or less during periods of precipitation), to prevent the accumulation of dirt and debris.
- The first 500 feet of any public roadway exiting the construction site will be cleaned on a periodic basis (or less during periods of precipitation), using wet sweepers or air-filtered dry vacuum sweepers, when construction activity occurs or on any day when dirt or runoff from the construction site is visible on the public roadways.
- Any soil storage piles and/or disturbed areas that remain inactive for longer than 10 days will be covered, or shall be treated with appropriate dust suppressant compounds.
- All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions will be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to minimize fugitive dust emissions. A minimum freeboard height of 2 feet will be required on all bulk materials transport.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition will remain in place until the soil is stabilized or permanently covered with vegetation.
- Disturbed areas, which are presently vegetated, will be re-vegetated as soon as practical.

To mitigate exhaust emissions from construction equipment, the Applicant is proposing the following:

- The Applicant will work with the general contractor to utilize to the extent feasible, Environmental Protection Agency (EPA)/Air Resources Board Tier II/Tier III engine compliant equipment for equipment over 100 horsepower.
- Ensure periodic maintenance and inspections per the manufacturers specifications.
- Reduce idling time through equipment and construction scheduling.
- Use California low sulfur diesel fuels (<=15 ppmw Sulfur).

Based on the temporary nature and the time frame for construction, the Applicant believes that these measures will reduce construction emissions and effects to levels that are less than significant. Use of these mitigation measures and control strategies will ensure that the site does not cause any violations of existing air quality standards as a result of construction-related activities. Appendix 5.1E, presents the evaluation of construction related emissions as well as data on the construction related ambient air quality effects.

Table 5.1-10, BAAQMD CEQA Significance Thresholds, presents data on the regional air quality significance thresholds currently being implemented by the BAAQMD. The specific construction and operational thresholds were derived from the BAAQMD California Environmental Quality Act (CEQA) guidance.

TABLE 5.1-10
BAAQMD CEQA Significance Thresholds

Pollutant	Annual Operations Thresholds	Daily Operations Thresholds
NO_x	15 tpy	80 lbs/day
CO	—	—
POCs	15 tpy	80 lbs/day
SO_x	—	—
PM_{10}	15 tpy	80 lbs/day
$PM_{2.5}$	—	—

Note: The BAAQMD has not established numerical thresholds for construction activities, but rather the BAAQMD relies upon a set of feasible control measures to mitigate emissions. The construction mitigation measures as proposed above and in Appendix 5.1E meet the Districts CEQA guidelines.

Source: BAAQMD CEQA Manual, 12/99.

In addition to the local and regional significance criteria, the following general conformity analysis thresholds are as follows in accordance with Code of Federal Regulations (40 CFR Parts 6 and 51):

- NO_x – 100 tons per year
- POCs – 100 tons per year
- CO – 100 tons per year
- SO_x – 100 tons per year
- PM_{10} – 100 tons per year
- $PM_{2.5}$ – no value available (use 100 tpy based on PM_{10} moderate non-attainment area value)

Emissions from the construction phase are not estimated to exceed the conformity levels noted above. Emissions from the operational phase are subject to the BAAQMD NSR and general permitting provisions, and as such, are exempt from a conformity determination or analysis.

5.1.4 Best Available Control Technology Evaluation

5.1.4.1 Current Facility Control Technologies

A detailed top down BACT evaluation is provided in Appendix 5.1F for the combustion turbines, auxiliary boiler, and evaporative fluid cooler, which includes a greenhouse gas control technology analysis. Table 5.1-11, BACT Values for Combustion Turbines/HRSGs, summarizes the control technologies currently proposed for use on the combustion turbines/HRSGs.

TABLE 5.1-11
BACT Values for Combustion Turbines/HRSGs

Pollutant	BACT Emissions Range*	Proposed BACT
NO_x	2.0 – 2.5 ppmvd	2.0 ppmvd
CO	3.0 – 6.0 ppmvd	2.0 ppmvd
POCs	2.0 ppmvd	1.0 ppmvd
SO_x Natural Gas	1.0 gr S/100 scf (short term) 0.33 gr S/100 scf (long term)	1.0 gr S/100 scf (short term) 0.25 gr S/100 scf (long term)
TSP, $PM_{10}/PM_{2.5}$	9.0 – 18 lb/hr	9.0 lb/hr

*Source: CARB, BAAQMD, SDAPCD, SJVUAPCD, and BAAQMD BACT Guidelines.
Source: Radback-OGS Team, 2010.

5.1.4.2 Proposed Best Available Control Technology

Table 5.1-12, Proposed BACT for the Combustion Turbines/HRSGs, presents the proposed BACT for the combustion turbines/HRSGs.

TABLE 5.1-12
Proposed BACT for the Combustion Turbines/HRSGs

Pollutant	Proposed BACT Emissions Level	Proposed BACT System(s)	Meets Current BACT Requirements
NO_x	2.0 ppmvd (1-hour)	DLN (turbine) with SCR	Yes
CO	2.0 ppmvd (1-hour)	Oxidation Catalyst	Yes
POCs	1.0 ppmvd	Oxidation Catalyst	Yes
SO_x	1.0 gr S/100 scf (short term) 0.25 gr S/100 scf (long term)	Natural Gas	Yes
TSP, $PM_{10}/PM_{2.5}$	9.0 lbs/hr	Natural Gas	Yes
NH_3	5.0 ppmvd	Reagent for SCR System 29.4% aqueous ammonia	Yes

Note: HRSGs are unfired.
Source: CARB, BAAQMD, SDAPCD, SJVUAPCD, and BAAQMD BACT Guidelines.

5.1.4.2.1 Evaporative Fluid Cooler BACT

BAAQMD Regulation 2, Rule 1, section 128.4 exempts the evaporative fluid cooler from the permit process and is, therefore, not subject to the BACT requirements of Regulation 13. Additionally, Regulation 2, Rule 1, section 319 exempts a source from permitting if the emissions are less than five (5) tpy. OGS emissions of $PM_{10/2.5}$ are less than 200 lbs/year from this source. BACT is referenced here for the CEC.. Due to the small size of the evaporative fluid cooler BACT for the evaporative fluid cooler will be high efficiency drift eliminators rated at 0.00003 drift fraction (0.003 percent) of the circulating water flow.

Additionally, no drift eliminators in the 0.0005% range are typically available. Thus, BACT at 0.003% is proposed.

5.1.4.2.2 Auxiliary Boiler BACT

The proposed auxiliary boiler is rated at 50.6 MMBtu/hr (HHV), and will be used for a maximum of 24 hours per day and, dependent upon operational scenario, up to 4,324 hours per year. The auxiliary boiler will be fired exclusively on natural gas and will be equipped with ultra low NO_x burners and flue gas recirculation. Exhaust concentrations of NO_x and CO will be limited to 7 and 10 ppmvd at 3% O_2, respectively. POC emissions will be controlled to a level of 5 ppmvd while PM_{10} emissions are estimated to be 0.007 lb/MMBtu (HHV). These emissions levels meet the BAAQMD BACT limits for limited use small boilers firing clean fuels such as natural gas. The auxiliary boiler will be equipped with continuous emissions monitors which will record emissions of NO_x, CO, and O_2.

5.1.4.2.3 Fire Pump Engine BACT

The fire pump engine will be fired exclusively on California certified ultra low sulfur diesel fuel and will meet all the emissions standards as specified in: (1) CARB ATCM, (2) EPA/CARB Tier III, (3) NSPS Subpart IIII, and (4) 40 CFR 63 Subpart ZZZZ. Due to the low use rate of the engine for testing and maintenance, as well as its intended use for emergency fire protection, the engine meets the current BACT requirements of the BAAQMD.

5.1.5 Air Quality Impact Analysis

This section describes the results, in both magnitude and spatial extent, of ground level concentrations resulting from emissions from the project site. The maximum modeled facility concentrations were added to the maximum background concentrations to calculate a total impact when appropriate (e.g., for comparison to ambient air quality standards).

Potential air quality impacts were evaluated based on air quality dispersion modeling, as described herein and presented in the Air Quality Modeling Protocol previously submitted and approved by the BAAQMD and the CEC. A copy of the Air Quality Modeling Protocol is included in Appendix 5.1. All input and output modeling files are contained on a CD-ROM disk provided to the BAAQMD and CEC Staff under separate cover. All modeling analyses were performed using the techniques and methods as discussed with the BAAQMD and CEC through development of the Air Quality Modeling Protocol.

5.1.5.1 Dispersion Modeling

For modeling the potential impact of the project site in terrain that is both below and above stack top (defined as simple terrain when the terrain is below stack top and complex terrain when it is above stack top) the USEPA guideline model AERMOD (version 09292) was used as well as the latest versions of the AERMOD preprocessors to determine surface characteristics (AERSURFACE version 08009), to process meteorological data (AERMET version 06341), and to determine receptor slope factors (AERMAP version 09040). The purpose of the AERMOD modeling analysis was to evaluate compliance with the California and federal air quality standards.

The nearest representative surface data set in the general area of the proposed project site is the PG&E database collected at the Contra Costa Power Plant (CCP), located approximately 1.5 km northwest of the project site. This surface meteorological data set was provided by the BAAQMD for the years 2001-02 and 2004-06 and, for each of the listed years, data recovery exceeds 90 percent. The corresponding upper air data was collected at the Oakland International Airport for the same time periods. The CCP meteorological data provided were already processed for input to AERMOD by BAAQMD for the surface characteristics based on the meteorological monitoring location. Due to the slight differences in surface roughness between the meteorological monitoring location and the project site, the merged data files provided by BAAQMD were re-processed with Stage 3 of AERMET for the surface characteristics of the project site location. AERSURFACE was executed for the project site using the BAAQMD-recommended sectors (76° – 147°, 147° – 277°, 277° – 355°, and 355° – 76°) and moisture conditions determined by BAAQMD for each month of every year of the original CCP dataset using Antioch Pump Plant 3 meteorological station precipitation data and the percentile method specified in the AERSURFACE User's Guide. Months were assigned to each season according to BAAQMD defaults as follows: spring—February and March; summer—April through July; autumn—August through October; and winter—November through January. Both sets of meteorological data will be used to model the facility in the screening analysis and the worst-case from either set of screening runs will be used in the refined modeling analyses. Albedo, Bowen ratio, and surface roughness were classified for the CCP meteorological monitoring location by the BAAQMD. These parameters were also determined for the project site to prepare a second set of modeling files for the screening analysis (as noted above, these surface characteristics are relatively consistent throughout the area, including the locations of the meteorological monitoring site and project site). The AERSURFACE program (version 08009) was used to generate the surface characteristics for the project site as specified in EPA's January 2009 AERMOD Guidance Document and AERSURFACE User's Guide using default settings where appropriate. Surface roughness was determined by AERSURFACE for the sectors determined by BAAQMD for each location (see Figure 2 in the Air Quality Modeling Protocol). These AERSURFACE inputs/outputs are listed below in Table 5.1-13, AERSURFACE Inputs/Outputs for Use in AERMET.

TABLE 5.1-13
AERSURFACE Inputs/Outputs for Use in AERMET

Month	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
Seasonal Assignments and Other Assumptions for Both Meteorological Datasets:												
Season	**Winter**	**Spring**	**Spring**	**Summer**	**Summer**	**Summer**	**Summer**	**Autumn**	**Autumn**	**Autumn**	**Winter**	**Winter**
Snow	No	—	—	—	—	—	—	—	—	—	No	No
Arid	No	No	No	No	No	No	No	No	No	No	No	No
Airport	No	No	No	No	No	No	No	No	No	No	No	No
Bowen Ratio Classification for each Month/Year based on Antioch Pump Plant 3:												
2001	Avg	Wet	Dry	Avg	Avg	Wet	Dry	Wet	Dry	Dry	Avg	Wet
2002	Dry	Dry	Avg	Dry	Dry	Dry	Dry	Dry	Dry	Dry	Avg	Wet
2004	Avg	Wet	Dry	Dry	Avg	Dry	Dry	Dry	Dry	Wet	Avg	Wet
2005	Wet	Avg	Wet	Avg	Avg	Wet	Dry	Dry	Dry	Dry	Dry	Wet
2006	Avg	Avg	Wet	Wet	Dry	Dry	Dry	Dry	Dry	Avg	Dry	Avg
SURFACE CHARACTERISTICS FOR THE CCP METEOROLOGICAL DATA LOCATION **(608644, 4208274 meters, UTM Zone 10, NAD83)** **Surface Roughness (meters) for Sectors 1 (62°-150°) / 2 (150°-182°) / 3 (182°-243°) / 4 (243°-274°) / 5 (274°-62°):**												

TABLE 5.1-13
AERSURFACE Inputs/Outputs for Use in AERMET

Month	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
Sector 1	0.437	0.493	0.493	0.550	0.550	0.550	0.550	0.550	0.550	0.550	0.437	0.437
Sector 2	0.317	0.397	0.397	0.460	0.460	0.460	0.460	0.460	0.460	0.460	0.317	0.317
Sector 3	0.433	0.488	0.488	0.534	0.534	0.534	0.534	0.534	0.534	0.534	0.433	0.433
Sector 4	0.609	0.634	0.634	0.651	0.651	0.651	0.651	0.651	0.651	0.651	0.609	0.609
Sector 5	0.041	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.041	0.041
Albedo	0.16	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Bowen Ratio by surface moisture (surface moisture classification for each month/year given at the top of this table):												
Avg	0.49	0.34	0.34	0.42	0.42	0.42	0.42	0.49	0.49	0.49	0.49	0.49
Wet	0.33	0.27	0.27	0.30	0.30	0.30	0.30	0.33	0.33	0.33	0.33	0.33
Dry	0.94	0.70	0.70	0.83	0.83	0.83	0.83	0.94	0.94	0.94	0.94	0.94
SURFACE CHARACTERISTICS FOR THE PROJECT SITE LOCATION (610176.8, 4207394.7 meters, UTM Zone 10, NAD27) Surface Roughness (meters) for Sectors 1 (76º-147º) / 2 (147º-277º) / 3 (277º-355º) / 4 (355º-76º):												
Sector 1	0.121	0.195	0.195	0.299	0.299	0.299	0.299	0.299	0.299	0.299	0.121	0.121
Sector 2	0.233	0.320	0.320	0.399	0.399	0.399	0.399	0.399	0.399	0.399	0.233	0.233
Sector 3	0.217	0.311	0.311	0.409	0.409	0.409	0.409	0.409	0.409	0.409	0.217	0.217
Sector 4	0.253	0.343	0.343	0.415	0.415	0.415	0.415	0.415	0.415	0.415	0.253	0.253
Albedo	0.16	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Bowen Ratio by surface moisture (surface moisture classification for each month/year given at the top of this table):												
Avg	0.52	0.34	0.34	0.43	0.43	0.43	0.43	0.51	0.51	0.51	0.52	0.52
Wet	0.34	0.26	0.26	0.30	0.30	0.30	0.30	0.34	0.34	0.34	0.34	0.34
Dry	1.00	0.71	0.71	0.88	0.88	0.88	0.88	1.00	1.00	1.00	1.00	1.00

Source: Modeling Protocol, 2009.

AERMOD input data options are listed below. Use of these options follows the USEPA's modeling guidance. Default model option[1] for temperature gradients, wind profile exponents, and calm processing, which includes final plume rise, stack-tip downwash, and elevated receptor terrain heights option, and all sources were modeled as rural sources.

To assess 1-hour NO_2 impacts, the Ozone Limiting Method (OLM keyword) was used to estimate the conversion of modeled short-term NO_X concentrations to NO_2 that involves a comparison of the modeled NO_X concentration and the ambient ozone concentration to determine the limiting factor to NO_2 formation. If the ozone concentration is greater than 90% of the maximum NO_X concentration, total conversion is assumed (10% of the NO_X emissions are assumed to be in the form of NO_2 that accounts for in-stack and near-stack thermal conversion). If the NO_X concentration (90% of modeled concentration) is greater than the ozone concentration, the formation of NO_2 is limited by the ambient ozone concentration. In this case, the NO_2 concentration is set equal to the ozone concentration plus 10% of the modeled concentration. Since the maximum impact locations occur in the immediate project vicinity,

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[1] To reduce run times for the area source modeled for fugitive dust and the large number of point sources modeled for mobile combustion source equipment, the FASTALL keyword was used for modeling construction impacts.

modeled concentrations are expected to be due to downwash effects so plumes were assumed to be well mixed due to downwash effects and all proposed facility sources were combined in a single OLM source group. For the OLM analysis, ozone data from the Pittsburg monitoring site was used. Short periods of missing data (less than 4-5 hours) were interpolated from available Pittsburg ozone data while Bethel Island ozone data were substituted for longer periods of missing data. To demonstrate compliance with the new 1-hour NO_2 NAAQS, a FORTRAN postprocessor program was used as recently suggested by USEPA to calculate the 5-year average of the 8th highest (98th percentile) daily maximum 1-hour NO_2 concentrations. Based on guidance contained in the last USEPA *"Guideline on Air Quality Models"* that addressed short-term NO_2 impacts, concurrent hourly NO_2 background concentrations measured at Pittsburg were added to the modeled NO_2 concentrations to determine the 5-year average of the 8th highest (98th percentile) daily maximum 1-hour NO_2 concentrations. Missing Pittsburg NO_2 data were interpolated or replaced by Bethel Island data similar to the ozone data processed for AERMOD OLM processing. The ozone data prepared for the OLM AERMOD modeling analysis (for the 1-hour CAAQS comparison) and the NO_2 data prepared for the postprocessor program (for the 1-hour NAAQS comparison) were concurrent with the 5-year AERMOD meteorological dataset described elsewhere (i.e., 2001-02 and 2004-06). Finally, for the long-term NO_2 impact analyses, the national USEPA-default Ambient Ratio Method (ARM) factor of 75% was used to convert modeled NO_X impacts to NO_2 concentrations (i.e., the OLM option in AERMOD was NOT used for annual averaging times, with NO_X being modeled as an inert pollutant).

5.1.5.2 Model Selection

Several other USEPA models and programs were used to quantify pollutant impacts on the surrounding environment based on the emission sources operating parameters and their locations. The models used were Building Profile Input Program for PRIME (BPIP-PRIME, current version 04274), the HARP On-Ramp preprocessor, and the SCREEN3 (version 96043) dispersion model for fumigation impacts. These models, along with options for their use and how they are used, are discussed below.

- Comparison of impacts to significant impact levels.
- Compliance with state and federal ambient air quality standards (AAQS).
- Calculation of health risk impacts through the use of the HARP On-Ramp program.

5.1.5.3 Good Engineering Practice Stack Height Analysis

The Good Engineering Practice (GEP) stack height was calculated at 310 feet based on existing onsite and offsite structure dimensions (i.e., the air-cooled condenser) for all onsite stacks (i.e., turbines, fire pump, and wet cells). The design stack heights are less than GEP stack height, thus downwash impacts were included in the modeling analysis.

BPIP-PRIME was used to generate the wind-direction-specific building dimensions for input into AERMOD. All on-site were included for analysis with BPIP-PRIME. The building location plan, located in Appendix 5.1B, shows the buildings included in the downwash analysis.

5.1.5.4 Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from the U.S. Geological Survey (USGS) Digital Elevation Model (DEM) data using 10-meter spacing between grid nodes. All coordinates were referenced to UTM North American Datum 1927 (NAD27), Zone 10. The receptor locations and elevations from the DEM files were placed exactly on the DEM nodes. Every effort was made to maintain receptor spacing across DEM file boundaries.

Cartesian coordinate receptor grids are used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impacts locations. The receptor grids used in this analysis are listed below.

- 10-meter resolution from the project site fenceline and extending outwards in all directions 500-meters. This is called the downwash grid. In addition, receptors were placed at 10-meter intervals or less along the project site fenceline.
- 50-meter resolution that extends outwards from the edge of the downwash grid to 2 kilometers in all directions. This is referred to as the intermediate grid.
- 200-meter resolution that extends outwards from the edge of the intermediate grid to about 10 kilometers in all directions (and more if necessary to calculate the extent of any significant impact area(s)). This is referred to as the coarse grid.
- 10-meter resolution around any location on the coarse and intermediate grids where a maximum impact is modeled that is above the concentrations on the downwash grid.
- For the HARP On-Ramp program, the minimum receptor spacing was changed to 100 meter resolution due to the limitation of the number of receptors On-Ramp can use.

Concentrations within the facility fence-line will not be calculated. The receptor grid figure, located in Appendix 5.1B, displays the receptors grids used in the modeling assessment. A facility boundary figure is also presented in Appendix 5.1B.

5.1.5.5 Meteorological Data Selection

The use of the five years of meteorological data collected at Oakley Generating Station (OGS) and provided by the BAAQMD as described above, which were also reprocessed to include surface characteristics for the project site location and included in the modeling analyses, satisfies the definition of on-site data. Detailed discussions of the representativeness of the meteorological data and comparisons of the CCP and project site locations (including aerial photo figures) are contained in the Air Quality Modeling Protocol (included in Appendix 5.1C) that was previously submitted and approved by the BAAQMD and the CEC.

A graphical wind rose for the 2001-02 and 2004-06 period prepared by the BAAQMD is attached to the Air Quality Modeling Protocol included in Appendix 5.1C. Five-year quarterly wind roses for the modeling data set are also provided in Appendix 5.1B.

The area surrounding the project site, within 3 kilometers, can be characterized as mostly rural in accordance with the Auer land use classification methodology (USEPA's "*Guideline on Air Quality Models*"), with the water of the San Joaquin River to the north and open/undeveloped areas, commercial/industrial areas, and residential areas surrounding the project site. Therefore, in the modeling analyses supporting the permitting of the facility, all emissions were modeled as rural sources. Aerial photos and a Auer land use classification of the project site are contained in the Air Quality Modeling Protocol.

5.1.5.6 Background Air Quality

In 1970, the United States Congress instructed the USEPA to establish standards for air pollutants, which were of nationwide concern. This directive resulted from the concern of the effects of air pollutants on the health and welfare of the public. The resulting Clean Air Act (CAA) set forth air quality standards to protect the health and welfare of the public. Two levels of standards were promulgated—primary standards and secondary standards. Primary national ambient air quality standards (NAAQS) are "those which, in the judgment of the administrator [of the USEPA], based on air quality criteria and allowing an adequate margin of safety, are requisite to protect the public health (state of general health of community or population)." The secondary NAAQS are "those which in the judgment of the administrator [of the USEPA], based on air quality criteria, are requisite to protect the public welfare and ecosystems associated with the presence of air pollutants in the ambient air." To date, NAAQS have been established for seven criteria pollutants as follows: SO_2, CO, ozone, NO_2, PM_{10}, $PM_{2.5}$, and lead.

The criteria pollutants are those that have been demonstrated historically to be widespread and have a potential to cause adverse health effects. USEPA developed comprehensive documents detailing the basis of, or criteria for, the standards that limit the ambient concentrations of these pollutants. The State of California has also established AAQS that further limit the allowable concentrations of certain criteria pollutants. Review of the established air quality standards is undertaken by both USEPA and the State of California on a periodic basis. As a result of the periodic reviews, the standards have been updated and amended over the years following adoption.

Each federal or state AAQS is comprised of two basic elements: (1) a numerical limit expressed as an allowable concentration, and (2) an averaging time which specifies the period over which the concentration value is to be measured. Table 5.1-14, State and Federal Ambient Air Quality Standards, presents the current federal and state AAQS.

TABLE 5.1-14
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards Concentration	National Standards Concentration
Ozone	1-hour	0.09 ppm (180 µg/m^3)	—
	8-hour	0.07 ppm (137 µg/m^3)	0.075 ppm (147 µg/m^3) (3-year average of annual 4th highest daily maxima)
Carbon Monoxide	8-hour	9.0 ppm (10,000 µg/m^3)	9 ppm (10,000 µg/m^3)
	1-hour	20 ppm (23,000 µg/m^3)	35 ppm (40,000 µg/m^3)
Nitrogen dioxide	Annual Average	0.030 ppm (57 µg/m^3)	0.053 ppm (100 µg/m^3)
	1-hour	0.18 ppm (339 µg/m^3)	0.100 ppm (188 µg/m^3) (3-year average of annual 98th percentile daily maxima)
Sulfur dioxide	Annual Average	—	0.030 ppm (80 µg/m^3)
	24-hour	0.04 ppm (105 µg/m^3)	0.14 ppm (365 µg/m^3)
	3-hour	—	0.5 ppm (1,300 µg/m^3)

TABLE 5.1-14
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards Concentration	National Standards Concentration
	1-hour	0.25 ppm (655 µg/m^3)	—
Respirable particulate matter (10 micron)	24-hour	50 µg/m^3	150 µg/m^3
	Annual Arithmetic Mean	20 µg/m^3	—
Fine particulate matter (2.5 micron)	Annual Arithmetic Mean	12 µg/m^3	15.0 µg/m^3 (3-year average)
	24-hour	—	35 µg/m^3 (3-year average of annual 98th percentile daily concentrations)
Sulfates	24-hour	25 µg/m^3	—
Lead	30-day	1.5 µg/m^3	—
	3 Month Rolling Average	—	0.15 µg/m^3

Source: CARB website, table updated 11/17/08

µg/m^3 = micrograms per cubic meter
ppm = parts per million

Brief descriptions of health effects for the main criteria pollutants are as follows.

Ozone—Ozone is a reactive pollutant that is not emitted directly into the atmosphere, but rather is a secondary air pollutant produced in the atmosphere through a complex series of photochemical reactions involving precursor organic compounds (POC) and NO_x. POC and NO_x are therefore known as precursor compounds for ozone. Significant ozone production generally requires ozone precursors to be present in a stable atmosphere with strong sunlight for approximately three hours. Ozone is a regional air pollutant because it is not emitted directly by sources, but is formed downwind of sources of POC and NO_x under the influence of wind and sunlight. Short-term exposure to ozone can irritate the eyes and cause constriction of the airways. In addition to causing shortness of breath, ozone can aggravate existing respiratory diseases such as asthma, bronchitis, and emphysema.

Carbon Monoxide—CO is a non-reactive pollutant that is a product of incomplete combustion. Ambient CO concentrations generally follow the spatial and temporal distributions of vehicular traffic and are also influenced by meteorological factors such as wind speed and atmospheric mixing. Under inversion conditions, CO concentrations may be distributed more uniformly over an area out to some distance from vehicular sources. When inhaled at high concentrations, CO combines with hemoglobin in the blood and reduces the oxygen-carrying capacity of the blood. This results in reduced oxygen reaching the brain, heart, and other body tissues. This condition is especially critical for people with cardiovascular diseases, chronic lung disease or anemia, as well as fetuses.

Particulate Matter (PM_{10} and $PM_{2.5}$)—PM_{10} consists of particulate matter that is 10 microns or less in diameter (a micron is 1 millionth of a meter), and fine particulate matter, $PM_{2.5}$, consists of particulate matter 2.5 microns or less in diameter. Both PM_{10} and $PM_{2.5}$ represent fractions of particulate matter, which can be inhaled into the air passages and the lungs and can cause adverse health effects. Particulate matter in the atmosphere results from many kinds of dust- and fume-producing industrial and agricultural operations, combustion, and atmospheric photochemical reactions. Some of these operations, such as demolition and construction activities, contribute to increases in local PM_{10} concentrations, while others, such as vehicular traffic, affect regional PM_{10} concentrations.

Several studies that the USEPA relied on for its staff report have shown an association between exposure to particulate matter, both PM_{10} and $PM_{2.5}$, and respiratory ailments or cardiovascular disease. Other studies have related particulate matter to increases in asthma attacks. In general, these studies have shown that short-term and long-term exposure to particulate matter can cause acute and chronic health effects. $PM_{2.5}$, which can penetrate deep into the lungs, causes more serious respiratory ailments.

Nitrogen Dioxide and Sulfur Dioxide—NO_2 and SO_2 are two gaseous compounds within a larger group of compounds, NO_x and SO_x, respectively, which are products of the combustion of fuel. NO_x and SO_x emission sources can elevate local NO_2 and SO_2 concentrations, and both are regional precursor compounds to particulate matter. As described above, NO_x is also an ozone precursor compound and can affect regional visibility. (NO_2 is the "whiskey brown-colored" gas readily visible during periods of heavy air pollution.) Elevated concentrations of these compounds are associated with increased risk of acute and chronic respiratory disease.

SO_2 and NO_2 emissions can be oxidized in the atmosphere to eventually form sulfates and nitrates, which contribute to acid rain. Large power facilities with high emissions of these substances from the use of coal or oil are subject to emissions reductions under the Phase I Acid Rain Program of Title IV of the 1990 CAA Amendments. Power facilities, with individual equipment capacity of 25 MW or greater that use natural gas or other fuels with low sulfur content, are subject to the Phase II Program of Title IV. The Phase II program requires facilities to install Continuous Monitoring Systems (CMS) in accordance with 40 CFR Part 75 and report annual emissions of SO_x and NO_x. Thus, the acid rain program provisions will apply to the project site. The project site will participate in the Acid Rain allowance program through the purchase of SO_2 allowances. Sufficient quantities of SO_2 allowances are available for use on this project site.

Lead—Gasoline-powered automobile engines used to be the major source of airborne lead in urban areas. Excessive exposure to lead concentrations can result in gastrointestinal disturbances, anemia, and kidney disease, and, in severe cases, neuromuscular and neurological dysfunction. The use of lead additives in motor vehicle fuel has been eliminated in California and lead concentrations have declined substantially as a result.

The nearest criteria pollutant air quality monitoring sites to the project site would be the stations located at Bethel Island, Pittsburg, and Concord. Ambient monitoring data for these sites for the most recent three-year period is summarized in Table 5.1-16, Summary of Air Quality Monitoring Data for the Most Recent 3 Year Period. Data from these sites is estimated to present a reasonable representation of background air quality for the project site and the facility's impact area.

Table 5.1-15, BAAQMD Attainment Status Table, presents the BAAQMD attainment status.

TABLE 5.1-15
BAAQMD Attainment Status

Pollutant	Averaging Time	Federal Status	State Status
Ozone	1-hr	NA	NA
Ozone	8-hr	NA	NA
NO_2	All	UNC/ATT	ATT
CO	All	ATT	ATT
SO_2	All	ATT	ATT
PM_{10}	All	UNC	NA
$PM_{2.5}$	All	NA	NA

ATT = attainment
NA = non-attainment
UNC = unclassified

Source: BAAQMD Website, 2008 and 40 CFR 81.305.

TABLE 5.1-16
Summary of Air Quality Monitoring Data for Most Recent 3-Year Period

Pollutant	Site	Avg. Time	2006	2007	2008
Ozone, ppm	Bethel Isl.	1-Hr Max	.116	.093	.109
	Pittsburg		.105	.100	.106
	Bethel Isl.	8-Hr Max	.085	.071	.076
	Pittsburg		.079	.067	.067
PM_{10}, µg/m^3	Bethel Isl.	24-Hr Max	82	47	78
	Pittsburg		58	56	74
	Bethel Isl.	Annual AM	19.4	18.8	24
	Pittsburg		19.9	19.4	20
$PM_{2.5}$, µg/m^3	Concord	24-Hr 98th Percentile	33.6	34.9	35.2
	Concord	Annual AM	9.3	8.4	9.3
CO, ppm	Bethel Isl.	1-Hr Max	1.3	1.1	1.0
	Pittsburg		3.3	2.8	2.8
	Bethel Isl.	8-Hr Max	1.0	.8	.8
	Pittsburg		1.9	1.5	1.4
NO_2, ppm	Bethel Isl.	1-Hr Max	.044	.048	.03
	Pittsburg		.052	.051	.044
	Bethel Isl.	1-Hr Daily Max 98th Percentile	.034	.036	.030
	Pittsburg		.043	.044	.044
	Bethel Isl.	Annual AM	.008	.008	.006
	Pittsburg		.011	.01	.009
SO_2, ppm	Bethel Isl.	1-Hr Max	.017	.018	.012
		3-Hr Max	.011	.013	.009
		24-Hr Max	.007	.005	.004

	Annual AM	.002	.002	.002
Pittsburg	1-Hr Max	.045	.047	.023
	3-Hr Max	.025	.024	.015
	24-Hr Max	.009	.007	.006
	Annual AM	.003	.002	.002

Source: AQMD website, Air Quality Monitoring Summaries for 2006-2008. EPA AIRS Data System, EPA Website, 2009.

Table 5.1-17, Background Air Quality Values, shows the background air quality values (converted to µg/m^3 when appropriate) based upon the data presented in Table 5.1-16, Summary of Air Quality Monitoring Data for the Most Recent 3-Year Period. The background values represent the highest values reported for any site during any single year of the most recent three-year period. Appendix 5.1B, , presents the background air quality data summaries.

TABLE 5.1-17
Background Air Quality Values

Pollutant and Averaging Time	Background Value, µg/m^3
Ozone – 1-hr	227
Ozone – 8-hr	166.5
PM_{10} – 24-hr	82
PM_{10} – Annual	24
$PM_{2.5}$ – 24-hr	35.2[a]
$PM_{2.5}$ – Annual	9.3
CO – 1-hr	3,771
CO – 8-hr	2,171
NO_2 – 1-hr	98.1
NO_2 – 3-yr Avg. of 98th% 1-hr Daily Max's	82.2[a]
NO_2 – Annual	20.8
SO_2 – 1-hr	122.2
SO_2 – 3-hr	65.0
SO_2 – 24-hr	23.4
SO_2 – Annual	7.8
Sulfate, 24-hr	ND

[a] Regulatory-defined background for project vicinity based on the 3-year average of the 2006-2008 98th percentile concentrations for the appropriate averaging time (February 26, 2009 BAAQMD guidance for PM2.5 and February 11, 2010 BAAQMD personal communication for NO_2). When modeling compliance with the new 1-hour NO_2 NAAQS using OLM, concurrent hourly NO_2 concentrations were used rather than the background value shown above.

5.1.5.6.1 Impacts on Class I and Class II Areas

Operational characteristics of the combustion turbine such as emission rate, exit velocity, and exit temperature vary by operating load and ambient temperature. The project site will be operated over a variety of these temperature ranges. Thus, the air quality analysis considered the range of operational characteristics over a variety of ambient temperatures. The screening modeling analysis, using AERMOD and the five-year set of hourly meteorology (i.e., years 2001-02 and 2004-06 of the CCP meteorological dataset prepared by BAAQMD for AERMOD and the same dataset reprocessed to include the surface characteristics Albedo, Bowen ratio, and surface roughness for the project site) was performed for various load conditions in order to determine the combustion turbine operating condition that will result in the highest modeled concentrations for averaging periods of 24 hours or less. These conditions were considered for following ambient temperature conditions: 34°F (a cold day), 59°F (average conditions), and 104°F (a hot day). The 59°F condition was assumed to represent annual average conditions. As such, no screening analyses were performed for annual average concentrations, which were modeled for the 59°F case at 100 percent load (combustion turbine inlet air evaporative cooling on), which is the typical operating scenario.

The results of the load screening analysis are listed in Appendix 5.1B. The screening analysis shows that the worst-case load and ambient temperature condition is 80 percent load at 34°F for all short-term impacts except for 49 percent load at 34°F for 24-hour PM10/2.5 impacts. The startup and commissioning modeling analysis used the worst-case dispersion conditions of 49 percent load at 34°F with maximum estimated emissions. In addition, the CCP meteorological data processed with the project site surface characteristics produced higher turbine screening impacts for all pollutants and averaging times. Therefore, the CCP meteorological data processed with the project site surface characteristics were used for the refined analysis and construction impacts modeling.

5.1.5.7 Refined Analysis

All facility sources were modeled in the analysis for comparisons with Significant Impact Levels (SILs) and California Ambient Air Quality Standards (CAAQS)/National Ambient Air Quality Standards (NAAQS), as necessary.

The project will use GE's Rapid Response technology which will limit all startup/shutdown periods to 90 minutes or less. Since AERMOD is based on one (1) hour steady state conditions, the startup/shutdown emission rate used for modeling assumed the remaining time periods were at full load operation. For example, to model the one (1) hour cold start condition of 90 minutes, the entire cold start emissions were assumed to be emitted over 45 minutes with the remaining 15 minutes in the hour were set to full load operation emissions after adjusting the full load emission by the time (0.25). For the two (2) proposed turbines, start-up/shutdown emissions were also accounted for in the refined analysis for all short-term (24-hours or less) and long-term (annual) averages in the air quality modeling. For modeling the short-term averaging times, the highest one-hour startup emissions from the combustion turbines (cold start) were used for determining one-hour NO_x and CO impacts. For the eight-hour CO modeling during startup, one cold start (1-hour), one shutdown (1-hour), one hot start and five (5) hours of base load operation were assumed (this scenario was used to assess a turbine trip during a startup period). The annual emission estimates already included emissions from start-up, shutdown, and maintenance activities. Detailed emission calculations for all averaging periods are included in Appendix 5.1A. The modeling assumptions included the following:

- Auxiliary boiler operation is 24 hours per day during turbine operation and 4,324 hours per year
- Fire pump operates 56 minutes per day, 49 hours per year

- Evaporative fluid cooler operates 24 hours per day and 1,500 hours per year
- Turbines operate 24 hours per day
- Worst-case annual emissions: 8,424 hours base load, 51 warm/hot starts, 1 cold starts, 52 shutdowns = 8,463 hours (Annual Case 3)
- Cold start is 45 minutes which is the worst case start plus 15 minutes of base load emissions
- CO 8-hour impacts calculated as 1 cold start + one hot start + one shutdown + 5 hours base load
- Fire pump not tested during 1 hour turbine start cycle but is included in the 8 hour start
- Aux boiler assumed to operate during a 1-hour cold start for the 1-hour startup modeling and two hours for 8-hour CO startup modeling

The worst-case modeling input information for each pollutant and averaging period are shown in Table 5.1-18, Stack Parameters and Emission Rates for the Modeled Sources, for normal operating conditions and combustion turbine startup/shutdown conditions. As discussed above, the combustion turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case operating condition for that pollutant and averaging period identified in the load screening analysis. Stack parameters associated with operation at 80 percent load and evaporative cooler off at 34°F were modeled for all short-term averaging times except 49 percent load at 34°F for 24-hour PM10 impacts. The 100 percent load case with evaporative cooler on at the annual average temperature of 59°F was used in modeling annual average impacts. The startup and commissioning modeling analysis used the worst-case dispersion conditions of 49 percent load at 34°F with maximum estimated emissions.

TABLE 5.1-18
Stack Parameters and Emission Rates for Each of the Modeled Sources

	Stack Height (m)	Stack Temp. (deg K)	Exit Vel. (m/s)	Stack Diam. (m)	Emission Rates (g/s)			
					NO_x	SO_2	CO	$PM_{10/2.5}$
Averaging Period: 1-hour for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	1.956	0.756	1.191	—
Fire Pump	4.877	714.26	32.22	0.2032	2.706E-1	5.040E-4	0.087	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	5.292E-2	1.764E-2	0.047	—
Averaging Period: 3-hours for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	0.756	-	—
Fire Pump	4.877	714.26	32.22	0.2032	—	1.680E-4	-	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	1.764E-2	-	—
Averaging Period: 8-hours for Normal Operating Conditions								
Each Turbine/HRSG	47.396	358.0	19.26	5.5992	—	—	1.191	—

TABLE 5.1-18
Stack Parameters and Emission Rates for Each of the Modeled Sources

	Stack Height (m)	Stack Temp. (deg K)	Exit Vel. (m/s)	Stack Diam. (m)	Emission Rates (g/s)			
					NO_x	SO_2	CO	$PM_{10/2.5}$
Fire Pump	4.877	714.26	32.22	0.2032	—	—	0.0109.	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	—	0.012	—
Averaging Period: 24-hours for Normal Operating Conditions								
Each Turbine/HRSG[a]	47.396	350.5[a]	14.16[a]	5.5992	—	0.756	—	1.134
Fire Pump	4.877	714.26	32.22	0.2032	—	2.100E-5	—	4.463E-4
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	1.470E-3	—	3.717E-3
Each Evap. Cooler Cell	7.010	304.21	10.19	3.353	—	—	—	5.544E-3
Averaging Period: Annual for Normal Operating Conditions								
Each Turbine/HRSG	47.396	361.4	22.04	5.5992	1.418	0.181	—	1.096
Fire Pump	4.877	714.26	32.22	0.2032	1.514E-3	2.819E-6	—	5.991E-5
Auxiliary Boiler	15.240	416.48	15.08	0.7620	2.435E-3	8.115E-4	—	2.052E-3
Each Evap. Cooler Cell	7.010	304.21	10.19	3.353	—	—	—	9.493E-4
Averaging Period: 1-hour for Cold Start-up/Shutdown Conditions								
Each Turbine/HRSG	47.396	350.5	14.16	5.5992	12.585	—	45.658	—
Fire Pump	4.877	714.26	32.22	0.2032	—	—	—	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	5.292E-2	—	0.047	—
Averaging Period: 8-hours for Cold Start-up/Shutdown Conditions								
Each Turbine/HRSG	47.396	350.5	14.16	5.5992	—	—	10.218	—
Fire Pump	4.877	714.26	32.22	0.2032	—	—	0.0109	—
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	—	0.012	—
Commissioning Period: 1-hour								
Turbine/HRSG N	47.396	350.5	14.16	5.5992	18.736	—	45.658	
Turbine/HRSG S	47.396	350.5	14.16	5.5992	12.585	—	88.20	
Auxiliary Boiler	15.240	416.48	15.08	0.7620	5.292E-2	—	0.047	
Commissioning Period: 8-hour								
Turbine/HRSG N	47.396	350.5	14.16	5.5992	—	—	88.20	
Turbine/HRSG S	47.396	350.5	14.16	5.5992	—	—	10.218	
Fire Pump	4.877	714.26	32.22	0.2032	—	—	0.0109	
Auxiliary Boiler	15.240	416.48	15.08	0.7620	—	—	0.047	

Source: Radback-OGS Team, 2010.

TABLE 5.1-18
Stack Parameters and Emission Rates for Each of the Modeled Sources

	Stack Height (m)	Stack Temp. (deg K)	Exit Vel. (m/s)	Stack Diam. (m)	Emission Rates (g/s)			
					NO_x	SO_2	CO	$PM_{10/2.5}$

[a] SO_2 24-hour worst-case Stack Temp and Exit Vel. from the screening analyses were 358.0 K and 19.26 m/s.

5.1.5.8 Normal Operations Impact Analysis

In order to determine the magnitude and location of the maximum impacts for each pollutant and averaging period, the AERMOD model was used. Table 5.1-19 summarizes maximum modeled concentrations for each criteria pollutant and associated averaging periods. In order to assess the significance of the modeled concentrations, they were compared to the Class II PSD SILs. All modeled facility pollutant concentrations are less than the federal significance impact levels with the exception of the proposed 24-hour and annual PM2.5 SIL. Annual impacts for the first year of commission activities were not assessed as these emissions are equal to the normal year operations.

Maximum impacts for 24-hour and annual averages for SO_2, NO_X, and $PM_{10/2.5}$ occurred in the 50-meter spaced intermediate grid. Therefore, additional 10-meter spaced refined receptor grids were modeled for these pollutants and averaging times. Additionally, the 8-hour CO startup was also modeled with the additional 10-meter spaced grid. The maximum impacts for the other pollutants and averaging times (i.e., NO_2 1-hour averages, CO 1-hour and 8-hour averages, and SO_2 1-hour and 3-hour averages) occurred in the immediate vicinity of the facility either on the fenceline or within the downwash grid in the 10-meter-spaced receptor areas. Therefore, no additional 10-meter-spaced receptor grids in the coarse or intermediate receptor grid areas were required for these pollutants/averaging times. Again, it should be noted that the refined modeling analyses was performed with the CCP meteorological data processed with the project site surface characteristics based on the results of the turbine screening analyses.

As stated previously, the maximum modeled impacts for all pollutants and averaging times are less than all applicable federal significance impact levels with the exception of the proposed 24-hour and annual PM2.5 SIL. However, the area has recently been redesignated as non-attainment for PM2.5. Therefore, the project site would not significantly affect the attainment status of any pollutant and facility impacts are considered to not be discernable from or significantly increase existing background pollutant concentrations. Facility impacts are also less than the 1-hour NO_2 CAAQS. Total concentrations (maximum modeled impacts plus maximum background concentrations) only exceed CAAQS/NAAQS for those pollutants and averaging times where background concentrations already equal or exceed the standards (i.e., the 24-hour and annual PM_{10} CAAQS and the 24-hour $PM_{2.5}$ NAAQS).

TABLE 5.1-19
Air Quality Impact Results for Refined Modeling Analysis of Project

Pollutant	Avg. Period	Maximum Concentration (µg/m^3)	Background (µg/m^3)	Total (µg/m^3)	Class II Significance Level (µg/m^3)	Ambient Air Quality CAAQS/NAAQS	
						(µg/m^3)	(µg/m^3)
Normal Operating Conditions							
NO$_2$ Max[a]	1-hour	126.0	98.1	224.1	-	339	-
NO$_2$ 98th%Avg[a]	1-hour	-	-	134.2[b]	-	-	188
NO$_2$[c]	Annual	0.44	20.8	21.2	1	57	100
CO	1-hour	52.6	3771	3824	2,000	23,000	40,000
	8-hour	8.7	2171	2180	500	10,000	10,000
SO$_2$	1-hour	10.1	122.2	132.3	-	655	-
	3-hour	7.5	65.0	72.5	25	-	1,300
	24-hour	2.0	23.4	25.4	5	105	365
	Annual	0.08	7.8	7.9	1	-	80
PM$_{10}$	24-hour	4.18	82	86.2	5	50	150
	Annual	0.46	24	24.5	1	20	-
PM$_{2.5}$	24-hour	4.18	35.2	39.4	1.2[d]	-	35
	Annual	0.46	9.3	9.76	0.3[d]	12	15.0
Start-up/Shutdown Periods							
NO$_2$ Max[a]	1-hour	-	-	274.1	-	339	-
NO$_2$ 98th%Avg[a]	1-hour	-	-	126.4[b]	-	-	188
CO	1-hour	763	3771	4534	2,000	23,000	40,000
	8-hour	95	2171	2266	500	10,000	10,000
Commissioning Activities							
NO$_2$ Max[a]	1-hour	198.5	98.1	296.6	-	339	-
NO$_2$ 98th%Avg[a]	1-hour	112.4	24.5	136.9[b]	-	-	188
CO	1-hour	1136	3771	4907	2,000	23,000	40,000
	8-hour	477	2171	2648	500	10,000	10,000

[a] NO$_2$ 1-hour impacts evaluated using the Ozone Limiting Method (OLM).
[b] Five-year average concentration of 8th-highest (98th percentile) daily maximum concentrations evaluated by a postprocessor, after including concurrent background NO$_2$ 1-hour concentrations.
[c] NO$_2$ annual impacts evaluated using the Ambient Ratio Method (ARM) with a USEPA-default ratio of 75%.
[d] Proposed significance levels. The projects impacts exceed the proposed SILs for PM2.5. The area has now been re-designated to non-attainment for PM2.5, thus no further analysis is proposed.
Source: Radback-OGS Team, 2010.

There are several scenarios that are possible during commissioning which are expected to result in NO$_X$, CO and POC emissions that are greater than during normal operations. During commissioning, SO$_2$ and PM$_{10/2.5}$ emissions are expected to be no greater than full load operations. Typically, some of the commissioning activities occur prior to the installation of the abatement equipment, e.g., SCR and oxidation catalyst, while the combustion turbines are being tuned to achieve optimum performance. During combustion turbine tuning, NO$_X$ and CO emission control systems would not be functioning.

For the purposes of air quality modeling, NO_2 and CO impacts could be higher during commissioning than under other operating conditions already evaluated. The commissioning activities for the combustion turbine are expected to consist of several phases. Though precise emission values during the phases of commissioning cannot be provided given the consideration for contingencies during shakedown, the worst case short-term emissions profile during expected commissioning-period operating loads are summarized in Table 5.1-20, Estimated Maximum Hourly Emissions Rates.

TABLE 5.1-20
Estimated Single Turbine Maximum Hourly Emissions Rates During Commissioning*

		NO_X	**CO**	**POC**	**$PM_{10/2.5}$**	**SO_x**
Emission Rate	lb/hr	148.7	700.00	37.9	9.0	6.0

* Turbines only
Source: Radback-OGS Team, 2010

The new combustion turbine's commissioning period (with and without SCR and CO catalyst loading), with an estimated duration of 831 operating hours total, is expected to consist of the following processes and time periods as delineated in Table 5.1-21, Commissioning Schedule.

TABLE 5.1-21
Commissioning Schedule

Stage	**Activities**	**Emissions Controls**	**Duration (time, hours)**
1	1) Combustion turbine first fire 2) Combustion turbine full speed/no load testing	DLN: None SCR/CO: None/None	72 hours per turbine 144 hours total
2	1) Steam blow 2) Combustion turbine tuning 3) Part load testing	DLN: Partial SCR/CO: None/None	218 hours per turbine 436 hours total
3	1) Combustion turbine full load testing 2) Combustion turbine tuning 3) SCR tuning	DLN: Partial SCR/CO: Partial/Partial	72 hours per turbine 144 hours total

Source: Radback-OGS Team, 2010

Both turbines could be commissioned at the same time. However, only one turbine will be operated during this process where the emissions would exceed the normal operational modes (which includes startup/shutdown). Appendix 5.1A lists the specific emissions during each phase of the commissioning activity.

The modeling presented in Table 5.1-19 summarizes the results of the commissioning assessment and assumes one turbine is in commissioning phase with the other turbine in startup operation.

Fumigation analyses with the USEPA Model SCREEN3 (version 96043) were conducted based on USEPA guidance given in *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019) and BAAQMD guidance contained in *"Permit Modeling Guidance"* (June 2007). Stack parameters for the worst-case 1-hour source configuration from the AERMOD screening analysis were used for the fumigation analysis.

Fumigation impacts for startup periods and commissioning activities were analyzed as well as normal operating conditions. The site is classified as a rural source location based on the Auer land use classification methodology. Therefore, only rural dispersion conditions were considered since there is no need to adjust fumigation impacts for urban dispersion conditions.

The inversion breakup fumigation impact of 1.243 micrograms/cubic meter (µg/m^3) for a unitized emission rate (1 gram/second, [g/s]) was predicted to occur 16,055 meters from the turbines for a single turbine stack under normal operating conditions. This result is predicted to occur by SCREEN3 for rural conditions of F stability and 2.5 m/s wind speed at the stack release height. At the inversion breakup fumigation distance for the turbines, the maximum auxiliary boiler and fire pump impacts were 8.469 and 11.10 µg/m^3, respectively, for a 1 g/s emission rate for each stack under rural conditions for all SCREEN3 meteorological combinations. No inversion breakup fumigation impacts are predicted to occur by SCREEN3 for the auxiliary boiler or fire pump stacks.

For startup periods and commissioning activities, the inversion breakup fumigation impact would be 1.608 µg/m^3 for a unitized emission rate of 1 g/s at a distance of 13,276 meters. The maximum auxiliary boiler and fire pump impacts were 10.23 and 13.46 µg/m^3, respectively, for a 1 g/s emission rate for all SCREEN3 meteorological combinations at this distance.

These unitized impacts were used to calculate 1-hour inversion breakup impacts for all pollutants by multiplying the unitized impacts by the pollutant emission rates (in g/s). The fumigation impacts from the two proposed turbines are added to the SCREEN3 fire pump and auxiliary boiler impacts at the same distance to obtain combined pollutant impacts for the entire facility. The maximum fumigation impact is compared to the maximum 1-hour impacts from the refined AERMOD analyses in the following table.

Table 5.1-22
Inversion Breakup Fumigation Impacts

Pollutant/Avg. Time	Fumigation Impact for Two (2) Turbines	Aux. Blr Impact	Fire Pump Impact	Total Impact	Maximum Impacts for Normal Dispersion from AERMOD/SCREEN3
Impacts (µg/m^3) at Inversion Breakup Distance for Normal Operating Conditions					
NO_X 1-hour	4.863	0.587	3.004	8.454	126/112
SO_2 1-hour	1.879	0.196	0.006	2.081	10.1/12.8
CO 1-hour	2.961	0.522	0.966	4.449	52.6/50.3
PM 1-hour	2.819	0.495	0.119	3.433	–/27.2
Impacts (µg/m^3) at Inversion Breakup Distance for Startup Periods					
NO_X 1-hour	40.473	0.712	–	41.185	176/266
CO 1-hour	146.836	0.633	–	147.469	763/934
Impacts (µg/m^3) at Inversion Breakup Distance for Commissioning Activities					
NO_X 1-hour	50.364	0.712	–	51.076	199/328
CO 1-hour	215.244	0.633	–	215.877	1136/1365

As shown above, the maximum 1-hour inversion breakup fumigation impacts are less than maximum 1-hour facility impacts predicted by AERMOD and/or SCREEN3 to occur under normal dispersion conditions. (Therefore, no further analysis of inversion breakup fumigation impacts for additional short-term averaging times (3-hours, 8-hours, or 24-hours) is required as described in Section 4.5.3 of *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019).

Shoreline fumigation impacts were also assessed since the nearest distance to the shoreline of the San Joaquin River is less than 3000 meters from the turbine stacks. Like the inversion breakup fumigation analysis, the SCREEN3 model was also used to perform the shoreline fumigation analysis. The default Thermal Internal Boundary Layer (TIBL) factor in the SCREEN3 model is set to a value of 6.0. Shoreline fumigation for TIBL factors from 2 to 6 were also calculated as required by the BAAQMD Modeling Guidance by revising and recompiling SCREEN3 for TIBL factors of 2.0, 3.0, 4.0, and 5.0. The final effective plume centerline height for the turbine stacks is 165 meters for rural conditions of F stability and 2.5 meter/second (m/s) wind speeds at the turbine stack release height. TIBL heights at the nearest turbine stack to the shoreline of the San Francisco Bay (a distance of about 950 meters) range from 62 to 154 meters for TIBL factors from 2.0 to 5.0 (for normal operating conditions). The TIBL height at the turbine stack location is greater than the final effective plume centerline height for a 6.0 TIBL factor under normal operating conditions and for TIBL factors of 5.0 and 6.0 for startup periods and commissioning activities, so no shoreline fumigation impacts would occur for these cases). No shoreline fumigation impacts are predicted to occur by SCREEN3 for either the fire pump or auxiliary boiler stacks for any TIBL factor modeled from 2.0 to 6.0. Like the inversion breakup fumigation analysis, SCREEN3 was used to assess impacts at the shoreline fumigation distance for these other facility sources using rural dispersion conditions with all SCREEN3 meteorological combinations and ignoring terrain at the distance of the maximum fumigation concentration.

The highest turbine shoreline fumigation impact from varying the TIBL factor was 8.730 $\mu g/m^3$ for a unitized emission rate of 1.0 g/s/turbine and a 5.0 TIBL factor at a distance of 1347 meters from the turbine stack for normal operating conditions. At this distance, the maximum auxiliary boiler and fire pump impacts were 56.85 and 76.96 $\mu g/m^3$, respectively, for a 1 g/s emission rate for each stack under rural conditions for all SCREEN3 meteorological combinations. For startup periods and commissioning activities, the maximum impacts for a 1 g/s emission rate are 7.635, 43.84, and 59.08 $\mu g/m^3$ for the turbines, auxiliary boiler, and firepump, respectively, at a distance of 2177 meters for a 4.0 TIBL factor. These unitized impacts were used to calculate total 1-hour impacts for the entire facility by multiplying the unitized impacts by the pollutant emission rates (in g/s) and adding the impacts together. These 1-hour pollutant impacts are shown in the following table.

TABLE 5.1-23
Shoreline Fumigation Impacts

Pollutant/Avg. Time	Fumigation Impact for Two (2) Turbines	Aux. Blr Impact	Fire Pump Impact	Total Impact	Maximum Impacts for Normal Dispersion from AERMOD/SCREEN3
Impacts (μg/m^3) for Shoreline Fumigation Distance for Normal Operating Conditions					
NO_X 1-hour	34.152	4.073	20.825	59.050	126/112
SO_2 1-hour	13.200	1.358	0.039	14.597	10.1/12.8
CO 1-hour	20.795	3.617	6.696	31.108	52.6/50.3
PM 1-hour	19.800	3.433	0.824	24.057	–/27.2
Impacts (μg/m^3) at Inversion Breakup Distance for Startup Periods					
NO_X 1-hour	192.173	3.127	–	195.300	176/266
CO 1-hour	697.198	2.777	–	699.975	763/934
Impacts (μg/m^3) at Inversion Breakup Distance for Commissioning Activities					
NO_X 1-hour	239.136	3.127	–	242.263	199/328
CO 1-hour	1022.006	2.777	–	1024.783	1136/1365

As shown above, the maximum 1-hour inversion breakup fumigation impacts are less than maximum 1-hour facility impacts predicted by AERMOD and/or SCREEN3 to occur under normal dispersion conditions for all pollutants other than SO_2. Therefore, no further analysis of shoreline fumigation impacts is required for NO_X, CO, and PM for additional short-term averaging times (3-hours, 8-hours, or 24-hours). For SO_2, impacts for other short-term averaging times were calculated as described in Section 4.5.3 of *"Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised"* (EPA-454/R-92-019). These SO_2 impacts are shown below compared to the significance levels and ambient air quality standards.

TABLE 5.1-24
SO_2 Impact Results for Shoreline Fumigation

Pollutant	Avg. Period	Maximum Concentration (μg/m^3)	Background (μg/m^3)	Total (μg/m^3)	Class II Significance Level (μg/m^3)	Ambient Air Quality CAAQS/NAAQS (μg/m^3)	(μg/m^3)
Normal Operating Conditions							
SO_2	1-hour	14.6	122.2	136.8	—	655	—
	3-hour	7.8	65.0	72.8	25	—	1,300
	24-hour	1.2	23.4	24.6	5	105	365

A comparison to Table 5.1-24 shows that the 1-hour and 3-hour SO_2 shoreline fumigation impacts are greater than the maximum refined AERMOD results. However, like the AERMOD results, all of these facility impacts are less than the applicable significance levels and total facility impacts plus background concentrations are far less than the ambient air quality standards. Therefore, the fumigation impacts do not change the conclusions of the refined AERMOD analyses.

Based upon emissions data provided to the Federal Land Managers (FLMs), specifically the United States Park Service (Dee Moris), the FLMs did not require a Class I air quality related values (AQRV) analyses to either deposition or visibility at the closest Class I areas, which are Pinnacles National Monument and Point Reyes National Seashore. A copy of the National Park Service letter exempting this project from a Class I ARQV analysis is included in Appendix 5.1C. However, the Class I areas were modeled for comparisons to the Federal Class I significance levels for increment analysis.

The projected impacts from all proposed criteria pollutant emissions were modeled at both Class I areas with CALPUFF in screening mode. As listed in Table 5.2-25, all impacts are well below the Significant Impact Levels (SIL) for all criteria pollutants and averaging periods.

To assess the potential for air quality impacts at the nearest Class I areas, Point Reyes National Seashore (86 to 112 kilometers from the project site) and Pinnacles National Monument (169 to 182 kilometers from the project site), the CALPUFF long-range transport model was used in a screening mode to assess the impacts of particulate matter (PM10 and PM2.5) and nitrogen dioxide (NO_2). The screening mode of CALPUFF uses a 3-dimensional homogeneous meteorological field for simulating transport and dispersion of pollutants for each hour. CALPUFF was used with the same meteorological data set that was approved in the 2006 application for RCEC that was approved by the BAAQMD. Specifically, five years of hourly surface and upper air data from a single monitoring station are required to identify the worst-case impacts when applying CALPUFF in a screening model.

Surface observations from San Francisco International Airport and upper air data from Oakland for 1986-1990 were used in the analysis. The PCRAMMET meteorological preprocessor was used to process the data. Five years of SCRAM surface data was supplemented with precipitation, surface pressure, relative humidity, and precipitation type data from the NCDC SAMSON/HUSWO CD-ROMs data sets.

CALPUFF was run with the recommended defaults specified in the IWAQM Phase II summary report. User-defined options were specified as follows:

- Number of X grid cells = 2
- Number of Y grid cells = 2
- Grid spacing = 165 kilometers for Point Reyes and 225 kilometers for Pinnacles
- Number of vertical layers = 2
- Cell face heights = 0, 5000

The projected impacts from all proposed criteria pollutant emissions were modeled at both Class I areas with AERMOD. As listed in Table 5.1-25, all impacts are below the Significant Impact Levels (SIL) for all criteria pollutants and averaging periods.

TABLE 5.1-25
Criteria Pollutant Class I SILs and Increments

Pollutant	Averaging Interval	Pinnacles (μg/m^3)	Point Reyes (μg/m^3)	Class I Significant Impact Level (μg/m^3)	Class I PSD Increment (μg/m^3)
NO_2	Annual	0.00066	0.00176	0.1	2.5
PM10	24-Hour	0.01890	0.04323	0.3	10
	Annual	0.00051	0.00136	0.2	5
PM2.5	24-Hour	0.01890	0.04323	0.07	10
	Annual	0.00051	0.00136	0.04	5

5.1.5.9 Impacts on Soils, Visibility, Vegetation, and Sensitive Species

This section provides an overview of the region including discussions of regional habitat and vegetation communities, regional special-status plant species, and the methods and results of biological surveys in and near the project site.

The project site is approximately 15 feet above mean sea level and can be found on the U.S. Geological Survey (USGS) Jersey Island, California 7.5-minute series topographic quadrangle within Section 22, Township 2 North, Range 2 East. The project facility will be located 0.25 mile north of State Route (SR) 4 and 0.1 mile east of SR160. Land use in the region includes residential, commercial, industrial, and agricultural.

A description of regional biogeography and habitat types was obtained from reference sources including *Ecological Subregions of California* (USDA, 1997), *Preliminary Descriptions of the Terrestrial Natural Communities of California* (Holland, 1986), *A Manual of California Vegetation* (Sawyer and Keeler-Wolf, 1995), the California Department of Fish and Game (CDFG) *Biological Information and Observation System* (BIOS, 2009), and the *California Environmental Resources Evaluation System* (CERES, 2008). The U.S. Fish and Wildlife Service (USFWS) National Wetlands Inventory (NWI) was also queried to determine the location of reported wetlands in proximity to the site (USFWS, 2009). These sources, as well as aerial photographs and USGS topographical maps, were consulted to determine the terrestrial and aquatic biological resources with potential to occur within 10 miles of the project site.

A list of sensitive biological resources for the region including natural communities and special-status plant and wildlife species was compiled for the project using the CDFG California Natural Diversity Database (CNDDB) RareFind3 database full condensed report for thirteen 7.5-minute USGS quadrangles including Birds Landing, Rio Vista, Isleton, Antioch North, Honker Bay, Jersey Island, Bouldin Island, Clayton, Antioch South, Brentwood, Woodward Island, Tassajara, and Byron Hot Springs (Appendix 5.2A, CDFG, 2009); California Native Plant Society's (CNPS) online Inventory (CNPS, 2000) for the 13 quadrangle region (Skinner et al., 1994); a USFWS species list for the 13 quadrangle region (Appendix 5.2B, USFWS 2009b); East Contra Costa County Habitat Conservation Plan/Natural Community Conservation Plan (ECCC HCP/NCCP) (Jones and Stokes, 2006); the Contra Costa County Breeding Bird Atlas (Herr, 2002); and project-specific onsite field surveys. A list of potentially occurring sensitive biological resources was generated for the region based on the combined results of these reference sources. The information in the reference sources listed above is based on known occurrences, historical records, or the presence of suitable habitat for any given life stage of a particular species.

Ecoregions are ecosystems of regional extent that share common climatic and vegetation characteristics. Ecoregions are hierarchically organized into domains, divisions, provinces, and sections. The project site lies within the Westside Alluvial Fans and Terraces subsection of the Great Valley Ecological Section (USDA, 1997). This subsection occurs on terraces and alluvial fans along the western edge of the San Joaquin Valley, adjacent to the Coast Ranges (Figure 5.2-1).

Generally, the predominant natural plant community in the Westside Alluvial Fans and Terraces subsection is needlegrass grassland, although none is reported or mapped in the CNDDB within 10 miles of the project site. Valley oak, northern claypan vernal pools, and stabilized interior dune communities are also present in the region. The Delta subsection to the north and east of the project site also contains several emergent aquatic natural plant communities including coastal and valley freshwater marsh and coastal brackish marsh along the San Joaquin River banks. The Central California Coast Range ecological section to the south of the site also contains cismontane alkali marsh, alkali seep, and alkali meadow natural communities.

Current land use within the region is mixed, with agriculture dominating the delta areas to the north and residential, commercial, and industrial uses near developed urban areas including Oakley (1.75 miles west of the site), Antioch (1.5 miles to the west), and Brentwood (4.5 miles to the south). SR 160 is approximately 0.1 mile west of the site, SR 4 is 0.25 mile to the south and a Burlington Northern-Santa Fe (BNSF) Railway is immediately adjacent to the south side of the project site. These transportation corridors connect the region to the San Francisco Bay Area and Sacramento-San Joaquin Delta.

The OGS site is approximately 0.6 mile south of the San Joaquin River, within the San Joaquin Delta Hydrologic Unit of the San Joaquin Hydrologic Region (BIOS, 2009).

Air emissions from the project include nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulates (PM_{10}). Nitrogen oxide gases (NO, NO_2) convert to nitrate particulates in a form that is suitable for uptake by most plants. The effect of this nitrogen could be to promote plant growth that could potentially encourage nonnative plant species at the expense of native species. Sensitive habitats that may harbor sensitive plant species susceptible to the effects of nitrogen deposition area located 1.6 miles west of the OGS site, at the Antioch Dunes National Wildlife Refuge.

To assess nitrogen deposition, AERMOD, which was used in the air quality permitting analysis to evaluate the project’s air quality impacts, was also used in the deposition analysis. As described previously, AERMOD is a steady-state, mass-conserving, nonreactive (i.e., no chemistry) plume dispersion model. The ability of AERMOD to overestimate impacts was expanded on by including several other assumptions with regards to nitrogen formation and deposition, in order to assess the potential for impacts from the OGS project. These assumptions include:

- 100 percent conversion of oxides of nitrogen (NO_x) and ammonia (NH_3) into atmospherically derived nitrogen (ADN) within the turbine stack(s) rather than allowing the conversion of NO_x and NH_3 to occur over distance and time within the atmosphere
- Depositional rates and parameters were based upon nitric acid (HNO_3) which, of all the depositional species, has the most affinity for impacts to soils and vegetation and the most tendency to "stick" to what it is deposited upon
- Maximum settling velocities to produce maximum deposition rates
- Maximum potential emissions were used rather than actual emissions in the calculation of nitrogen deposition
- And, once it leaves the turbine stack, nitrogen immediately begins to deposit in the surrounding lands.

To produce conservative results (overestimates), modeling assumptions regarding the complex chemistry that occurs to produce nitrogen from NO_x, ammonia, and other pollutants were not used in this modeling analysis. As one example, it was assumed that the pollutants leaving the stack(s) would already be in the form of depositional nitrogen (nitrate and ammonium ions). To do this, the emissions of NO_x and ammonia were summed and then adjusted for the molecular weight of nitrogen. Thus, all impacts would represent 100 percent conversion of combustion emissions into depositional nitrogen. This assumption leads to an exceedingly conservative estimation of nitrogen deposition, because areas with the highest nitrogen emissions do not necessarily experience the greatest deposition effects, which usually occur far from the original nitrogen source. In addition, since mass is conserved in the model, all downwind calculations of nitrogen deposition, regardless of distance and formation rates, are overestimated by the model.

The AERMOD model calculates atmospheric deposition of nitrogen by calculating the wet and dry fluxes of total nitrogen. This deposition is accomplished by using a resistance model for the dry deposition part, and by assigning particle phase washout coefficients for the wet removal process from rainout. As discussed below, depositional parameters are input into the model in order to calculate the deposition of nitrogen. Again, depositional parameters were based on HNO_3, which is consistent with the conservative modeling assumptions that overestimate the amounts of nitrogen deposition from the proposed project. Nitric acid tends to deposit more readily than most other compounds.

No chemical conversion (which takes place over distance and time) was allowed to occur. In reality, the nitrate aerosol cannot be considered a stable product, such as sulfate typically is. Also, unlike sulfate, the ambient concentration of atmospherically derived nitrogen is limited by the availability of ammonia, which is preferentially scavenged by sulfate. Because of the preferential scavenging of ammonia by sulfate, the available ammonia in the atmosphere is often computed as total ammonia minus sulfate. These effects were not included in the analysis.

The assumption that atmospherically derived nitrogen forms instantaneously in stack and immediately begins to deposit in the surrounding areas leads to an estimation of nitrogen deposition that is unrealistically high, and would likely be several orders of magnitude higher than the actual process itself. This is especially true in the immediate area(s) surrounding the project site.

The other assumptions listed above, along with those inherent in AERMOD, add to the conservative nature of the modeling analysis. All these factors were combined into one modeling study to produce much higher impacts than would be modeled using less conservative assumptions. The goal of the analysis was to combine many conservative assumptions into one modeling analysis in order to overestimate the potential impact from operation of the OGS project.

In order to model gaseous deposition, the model requires land use characteristics and gas deposition resistance terms based on five seasonal categories. The seasonal categories are input into AERMOD on a month by month basis, corresponding to each summer, fall, winter, and spring seasons. Additionally, land use data is input based on wind direction.

For both wet and dry deposition, AERMOD requires the following additional inputs:

- The molecular diffusivity (D_a) for the pollutant being modeled [cubic centimeters per second (cm^2/s)]
- The diffusivity in water (D_w) for the pollutant being modeled [cubic centimeters per second (cm^2/s)]
- The cuticular resistance to uptake by lipids for individual leaves (rcl) for the pollutant (s/cm),
- The Henry's Law coefficient (Pa) for the parameter (m^3/mol)

For this analysis, it was assumed that the deposition parameters would be based on gaseous nitric acid. Nitric acid was chosen to represent total nitrogen deposition since nitric acid has the greatest potential for depositional effects. The deposition parameters were obtained from a draft Argonne National Laboratory report (Wesely, et. al., 2002).

In addition to the above inputs, the dry and wet deposition algorithm also requires surface roughness length (cm), friction velocity (meters per second), Monin-Obukhov length (meters), surface pressure, precipitation type, and precipitation rate. For AERMOD, the meteorology used in this analysis was based on the 2003-2007 data set collected at the Oakland International Airport. This is the same meteorological data set that was used for the air quality permit application.

The Antioch Dunes critical habitat was assigned a unique vegetative and land use type. The Antioch Dunes critical habitat area land use is best described as rangeland to model deposition, including the surface roughness length, leaf-area index, and plant-growth state. For roughness lengths, domain-averaged values for rangeland for both an active growing season and an inactive season were identified. Leaf area indices were also based on domain-averaged values for an active growing season and an inactive/dormant season. To calculate nitrogen deposition velocities, the state of the vegetation must also be specified and included both active and stressed active an unstressed.

This approach was used to develop conservative, worst-case scenarios to evaluate potential nitrogen deposition on the critical habitat. The following scenario was used in the assessment of nitrogen depositional fluxes:

Hayward Regional Seashore

- Land use: rangeland
- Vegetation state: active and stressed
- Roughness length = 0.5 meter
- Leaf area index = 0.5
- Diffusivity in air = 0.16E-04 (cm^2/s)
- Diffusivity in water = 0.30E-08 (cm^2/s)
- Leaf Lipid Resistance = 0.10E+08 (s/cm)
- Henry's Law Coefficient = 0.80E-07 (m^3/mol)

Results of the wet and dry nitrogen deposition modeling were summed to produce annual deposition rates in units of kilograms per hectare per year (kg/ha-yr). As the critical habitats cover a variety of elevations and distances, the maximum deposition rate calculated all receptors was used to for comparison to significance. The maximum project nitrogen deposition rates would be 0.08912 kg/ha/yr, based on the worst-case NO_x and ammonia emissions of 8,463 hours per year.

A threshold at which harmful effects from nitrogen deposition on plant communities has not been firmly established. However, a value of 5 kilograms per hectare per year (kg/ha/yr) is often used for comparing nitrogen deposition among plant communities. Research conducted in the South San Francisco Bay Area indicates that intensified annual grass invasions can occur in areas with nitrogen deposition levels of 11–20 kg/ha/yr, with limited invasions at levels of 4–5 kg/ha/yr (Weiss 2006a and Weiss 2007, as cited in CEC 2007). The levels of nitrogen deposition from the project in the Antioch Dunes area are estimated at 0.08912 kg/ha/yr, far below levels necessary to cause adverse effects.

Furthermore, the level of nitrogen deposition from the project emissions on plant-available nitrogen would actually be less than the calculated amount because the deposition will be distributed in small amounts during the year and not all of the nitrogen added to the soil during each deposition event is available for plant use because of losses associated with soil processes. Therefore, it is unlikely that there would be significant impacts to biological resources from nitrogen deposition.

Particulate emissions will be controlled by inlet air filtration and use of natural gas. The deposition of airborne particulates (PM_{10}) can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Information on physical effects is scarce, presumably in part because such effects are slight or not obvious except under extreme situations (Lodge et al., 1981). Studies performed by Lerman and Darley (1975) found that particulate deposition rates of 365 g/m^2/year caused damage to fir trees, but rates of 274 g/m^2/year and 400 to 600 g/m^2/year did not damage vegetation at other sites.

The maximum annual PM10 impact for the facility is 0.46 $\mu g/m^3$. Assuming a deposition velocity of 2 cm/sec (worst-case deposition velocity, as recommended by the California Air

Resources Board [CARB]), this concentration converts to an annual deposition rate of 0.290 g/m^2/year, which is several orders of magnitude below that which is expected to result in mechanical injury to vegetation (i.e., 365 g/m^2/year; Lerman and Darley, 1975). Even the maximum annual background concentration of 24 μg/m^3, representative of the project vicinity, yields a total estimated particulate deposition rate of 15.318 g/m^2/year, still approximately one order of magnitude less than levels expected to result in plant injury.

The primary chemical mechanism for airborne particulates to cause injury to vegetation is by trace element toxicity. Many factors may influence the effects of trace elements on vegetation, including temperature, precipitation, soil type, and plant species (USFWS, 1978). Trace elements adsorbed to particulates emitted from power plant emissions reach the soil through direct deposition, the washing of plant surfaces by rainfall, and the decomposition of leaf litter. Ultimately, the potential toxicity of trace elements that reach the root zone through leaching will be dependent on whether the element is in a form readily available to plants. This availability is controlled in part by the soil cation exchange capacity, which is determined by soil texture, organic matter content, and the kind of clay present. Soil pH is also an important influence on cation exchange capacity; in acidic soils, the more mobile, lower valence forms of trace metals usually predominate over less mobile, higher valence forms. The silty clay and clay soils in the project area will have a lower potential for trace element toxicity from the comparatively high soil pH commonly found in local soils.

Perhaps the most important consideration in determining toxicity of trace elements to plants relates to existing concentrations in the soil. Several studies have been conducted relating endogenous trace element concentrations to the effects on biota of emissions from model power plants (Dvorak et al., 1977; Dvorak and Pentecost et al., 1977; Vaughan et al., 1975). These studies revealed that the predicted levels of particulate deposition for the area surrounding the model plant resulted in additions of trace elements to the soil over the operating life of the plant that were, in most cases, less than 10 percent of the total existing levels. Therefore, uptake by vegetation could not increase dramatically unless the forms of deposited trace elements were considerably more available than normal elements present in the soil.

The maximum potential nitrogen deposition rates that have been estimated for the Antioch Dunes critical habitat area are small compared to the nutritional nitrogen requirement of non-native grasses. Therefore, the small incremental impact of the proposed operation is insignificant given the small increase in depositional species.

Plume Blight Analysis

A plume blight analysis was conducted for surrounding Class II area for emissions from the OGS project, in accordance with PSD requirements for Class II visibility. The VISCREEN model (version 1.01) was used to conduct the plume blight analysis with a background visual range of 110 kilometers, as recommended in the "Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015).

VISCREEN was developed to conduct a visual effect evaluation of a plume as observed from a given vantage point located 10 kilometers from the Project site. Emissions input into the model are assumed to create an infinitely long, straight plume traveling toward the specified area. The model outputs the change in light extinction in terms of Delta E and contrast against both a terrain and sky background.

Table 5.1-28 contains the results of the Level 1 VISCREEN analysis for the surrounding Class II area. Potential NO_x and PM10 emissions were used for this analysis. Results of the VISCREEN analysis were compared to criteria provided in FLAG. There are no Class II visibility standards or levels of significance.

TABLE 5.1-27

Level 1 VISCREEN Analysis Results

Class II Area	**Nearest Boarder**	**Furthest Boarder**	**Delta E**				**Contrast**			
			Sky 10	**Sky 140**	**Terrain 10**	**Terrain 140**	**Sky 10**	**Sky 140**	**Terrain 10**	**Terrain 140**
Class II Visibility Analysis (inside Class II Area)	10	20	5.326	2.851	16.247	2.253	0.078	-0.055	0.119	**0.024**
Class II Visibility Analysis (outside Class II Area)	10	20	15.951	5.225	40.533	5.736	0.328	-0.155	0.343	**0.081**
Criteria[1]			2.00	2.00	2.00	2.00	0.05	0.05	0.05	0.05

1. Criteria for Delta E and Contrast are the default criteria suggested by FLAG.

5.1.6 Laws, Ordinances, Regulations, and Statutes (LORS)

Table 5.1-28 presents a summary of federal, state, and local air quality LORS deemed applicable to the project site.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Federal			
Title 40 CFR Part 50	Establishes AAQS for criteria pollutants.	EPA Region IX	OGS will conduct a dispersion modeling analysis to determine if the project will exceed the state or federal AAQS. Dispersion modeling indicates the OGS will not exceed the state or federal AAQS for the attainment pollutants. Non-attainment pollutant emissions will be mitigated through the surrendering of emission reduction credits consistent with the BAAQMD's SIP-Approved New Source Review program.
Title 40 CFR Part 51, NSR (BAAQMD Reg 2 Rule 2)	Requires pre-construction review and permitting of new or modified stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient air quality standards.	EPA Region IX	Requires NSR facility permitting for construction or modification of specified stationary sources. The NSR requirements are implemented at the local level with EPA oversight (BAAQMD Reg 2 Rule 2). Because the OGS will exceed the 10 lb/day trigger for at least one of the regulated pollutants, an ATC and PTO application will be obtained from the BAAQMD prior to construction of the project site. As a result, the compliance requirements of 40 CFR, Part 51.165 will be met.
Title 40 CFR Part 52, PSD	The PSD program allows new sources of air pollution to be constructed or existing sources to be modified in areas classified as attainment, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I Areas (e.g., national parks and wilderness areas).	EPA Region IX	The PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing major stationary source. BAAQMD classifies an unlisted source (which is not in the specified 28 source categories) that emits or has the potential to emit 250 tons per year (tpy) of any pollutant regulated by the Act as a major stationary source. For listed sources, the threshold is 100 tpy. NO_x or SO_x emissions from a modified major source are subject to PSD if the cumulative emission increases for either pollutant exceeds 40 tpy. In addition, a modification at a non-major source is subject to PSD if the modification itself would be considered a major source. Because the OGS is a combined-cycle project, it would be considered one of the 28 source categories. Therefore, the emission rates were compared to the 100 ton per year threshold. As shown in Table 5.1-9,none of the emissions exceed the major source thresholds of 100 tons per year. Therefore, OGS would not be subject to PSD analysis requirements.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR, Part 60	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD with EPA Region IX oversight	**Turbines:** 40 CFR Part 60 Subpart KKKK – NO_x Emission Limits for New Stationary Combustion Turbines applies to all new combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. The rule requires natural-gas-fired turbines greater than or equal to 30 MW to meet a NO_x emission limit of 50 nanograms per Joule (ng/J) (0.39 pounds per megawatt-hour [lb/MW-hr]), and an SO_2 limit of 73 ng/J (0.58 lb/MW-hr). Alternatively, a fuel sulfur limit of 500 parts per million by weight (ppmw) could be met. Stationary combustion turbines regulated under this subpart would be exempt from the requirements of Subpart GG. The proposed turbines will utilize low NO_x combustors along with an SCR system, pipeline-quality natural gas, and will comply with both the NO_x and SO_2 limits. The certified NO_x Continuous Emission Monitoring System (CEMS) will ensure compliance with the standard. Records of natural gas usage and fuel sulfur content will ensure compliance with the SO_2 limit.
Title 40 CFR, Part 60	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD with EPA Region IX oversight	**Fire Pump:** 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines) would apply to the diesel fire pump. The NMHC+NO_x emission limit for a model year 2009 fire pump between 300 and 600 hp would be 3.0 g/bhp, the CO emission limit would be 2.6 g/bhp, and the PM_{10} emission limit would be 0.15 g/bhp. The proposed CI ICE used to operate the emergency fire pump would be a Tier III, 400 bhp ICE. Therefore, the engine would meet the NMHC+NO_x, CO, and PM_{10} emission standards.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CFR, Part 63	Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific categories.	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 63—National Emission Standards for Hazardous Air Pollutants for Source Categories, establishes emission standards to limit emissions of hazardous air pollutants from specific source categories for Major HAP sources. Sources subject to Part 63 requirements must either use the maximum achievable control technology (MACT), be exempted under Part 63, or comply with published emission limitations. The potential NESHAPS applicable to the project issubpart ZZZZ, the NESHAPS for Stationary Reciprocating Internal Combustion Engines (RICE). Subpart YYYY (MACT for stationary gas turbines) was vacated by the courts and is no longer applicable. As shown in Section 5.9 (Public Health), OGS will exceed the major source thresholds for HAPs (10 tpy for any one pollutant (formaldehyde) or 25 tpy for all HAPs combined). As such, the turbines at OGS are subject to a case-by-case MACT determination. Installation and use of the proposed CO catalyst on each turbine meets the MACT requirements at this time. Subpart ZZZZ applies to area (minor) sources as well as major sources. Therefore, OGS will be subject to Subpart ZZZZ for the fire pump engine.
Title 40 CFR Part 64 (CAM Rule)	Establishes onsite monitoring requirements for emission control systems.	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 64—Compliance Assurance Monitoring (CAM), requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency. If an emission control system is not working properly, the CAM rule also requires a facility to take action to correct the control system malfunction. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. Emission control systems governed by Title V operating permits requiring continuous compliance determination methods are generally exempt from the CAM rule. OGS would have an emission control systems for NO_x and CO (SCR and oxidation catalyst). However, emissions of NO_x and CO would be directly measured by a continuous monitoring system. Therefore, OGS would not be subject to the CAM provisions.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
Title 40 CRF part 70 (BAAQMD Reg 2, Rule 6)	CAA Title V Operating Permit Program	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 70—Operating Permits Program, requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. The requirements of 40 CFR, Part 70 apply to facilities that are subject to NSPS requirements and are implemented at the local level through BAAQMD Reg 2, Rule 6. According to Reg 2, Rule 6, a facility would be considered a Major Facility if the facility had a potential to emit greater than 100 tpy on a pollutant specific basis or the HAP PTE is greater or equal to 25 tpy for combined HAPs and 10 tpy for individual HAPs.
Title 40 CFR part 72 (BAAQMD Reg 2, Rule 7)	CAA Acid Rain Program	BAAQMD with EPA Region IX oversight	Title 40, Code of Federal Regulations, Part 72—Acid Rain Program, establishes emission standards for SO_2 and NO_x emissions from electric generating units through the use of market incentives, requires sources to monitor and report acid gas emissions, and requires the acquisition of SO_2 allowances sufficient to offset SO_2 emissions on an annual basis. This program is implemented through BAAQMD's Reg 2, Rule 7. An acid rain facility, such as OGS, must also obtain an acid rain permit as mandated by Title IV of the Clean Air Act. A permit application must be submitted to the BAAQMD at least 24 months before operation of the new units commences. The application must present all relevant sources at the facility, a compliance plan for each unit, applicable standards, and estimated commencement date of operation. The necessary Title IV applications will be included during the CEC licensing proceeding.
State			
California Code of Regulations, Section 41700	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	BAAQMD with ARB oversight	The CEC conditions of certification and the air quality management district (AQMD) ATC processes are developed to ensure no adverse public health affects or public nuisances result from operation of the project site.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
California Code of Regulations Sections 93115 (Diesel ATCM)	The purpose of the airborne toxics control measure (ATCM) is to reduce diesel particulate emissions from stationary diesel fired compression engines.	BAAQMD with ARB oversight	The diesel ATCM applies to stationary compression engines with a rating of greater than 50 brake horsepower and requires the use of ARB-certified diesel fuel or equivalent, and limits emissions from the operation of compression engines. The proposed fire pump would be greater than 50 bhp. However, the fire pump would meet the Tier III emission standards and non-emergency hours of operation would be limited to 50 hours or less per year. Therefore, the project site would comply with the diesel ATCM.
California Assembly Bill 32 – Global Warming Solutions Act of 2006 (AB32)	The purpose is to reduce carbon emissions within the state by approximately 25% by the year 2020.	BAAQMD with ARB oversight	There are currently no applicable facility-specific greenhouse gas emission limits or caps. Therefore, greenhouse gas emissions have been estimated for OGS for informational purposes at this time.
Local			
BAAQMD Reg 1, Section 301 (Public Nuisance)	Prohibits the emissions of air contaminants or other material which create a public nuisance.	BAAQMD	The CEC conditions of exemption and the BAAQMD ATC process is designed to ensure that the operation of the project site will not cause a public nuisance.
BAAQMD Regulation 2, Rule 2 (Permits – NSR)	Purpose of this Rule is to provide for the review of new and modified sources and provide mechanisms, including the use of Best Available Control Technology (BACT), Best Available Control Technology for Toxics (TBACT), and emission offsets, by which authorities to construct such sources may be granted.	BAAQMD	Applicability: As part of the NSR permit approval process, an air quality dispersion analysis must be conducted using a mass emissions-based analysis contained in the rule or an approved dispersion model, to evaluate impacts of increased criteria pollutant emissions from any new or modified facility on ambient air quality. Compliance: An air quality dispersion analysis was conducted, using a mass emissions-based analysis contained in the rule and the AERMOD dispersion model. Applicability: The PSD requirements apply on a pollutant-specific in areas attaining the state and federal AAQS to any project that is a new major stationary source or a major modification to an existing major stationary source. (See Title 40 CFR Part 51 and Part 52 discussion for thresholds). This project is not subject to the PSD requirements. Applicability: BACT shall be applied to all new and modified sources with a potential to emit 10 pounds or more of any of the following: POC, NPOC, NOx, SO_2, PM_{10} or CO. (BAAQMD 2-2-301). Compliance: Based on the BACT thresholds, a BACT analysis was conducted for the following: POC, NOx, PM_{10} and CO. Applicability: A source shall be exempt from MACT requirements if the

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
			combined potential to emit from all related sources in a proposed modification is less than 10 tpy of any HAP and less than 25 tpy of any combination of HAPs. (BAAQMD 2-2-114). Compliance: The OGS does exceed the major source thresholds for HAPs (10 tpy for any one pollutant or 25 tpy for all HAPs combined). MACT for the stationary gas turbines is the installation and use of a CO oxidation catalyst. Applicability: Offsets for NOx are required at a 1.0 to 1.15 ratio if a modification to the permit causes a cumulative increase greater than 35 tpy. Offsets for POC are required for sources less than 35 pty at a offset ratio of 1.0 to 1.0. Offsets for PM_{10} and SO_x are required for a Major Facility at a 1.0 to 1.0 ratio if a modification to the permit causes a cumulative increase of 100 tpy. (BAAQMD 2-2-302 and 2-2-303). See Appendix 5.1G for offset strategy. The project is subject to offsets for NOx and POC. Applicability: A visibility, soils, and vegetation analysis is required if the proposed project is subject to PSD requirements and is within 10 kilometers of a Class I Area. (BAAQMD 2-2-417).
BAAQMD Regulation 2, Rule 3 (Permits – ATC and Permit to Operate [PTO] for Power Plants)	The purpose of this rule is to outline the special permitting provisions for the construction of power plants within the District.	BAAQMD	In conjunction with the submittal of the AFC to the CEC, OGS will work with the BAAQMD to provide the information needed for the issuance of a ATC. As stated in this rule, the review will be conducted as outlined in Regulation 2, Rule 2.
BAAQMD Regulation 2, Rule 5 (Permits – Toxics NSR)	The purpose of this rule is to provide for the review of new and modified sources of TAC emissions in order to evaluate potential public exposure and health risk, to mitigate potentially significant health risks resulting from these exposures, and to provide net health risk benefits by improving the level of control when existing sources are modified or replaced.	BAAQMD	TBACT shall be applied to any new or modified source of TACs where the source risk is a cancer risk greater than 1.0 in a million (10^{-6}), and/or a chronic hazard index greater than 0.20. An ATC or PTO will be denied if the facility cancer risk exceeds 10 in a million, or the facility chronic hazard index exceeds 1.0, or the facility acute hazard index exceeds 1.0. Section 5.9 and Appendix 5.1D present the results of the facility risk assessment, which shows compliance with all applicable AQMD significance values.
BAAQMD Regulation 2, Rule 6 (Permits – Title V)	The purpose of this rule is to implement the operating permit requirements of Title V of the CAA as amended in 1990.	BAAQMD with EPA Oversight	See Federal, Title 40 CFR, Part 70 to review applicability and the compliance assessment.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
BAAQMD Regulation 2, Rule 7 (Permits – Acid Rain)	The purpose of this rule is to incorporate by reference the provisions of 40 CFR Part 72 for purposes of implementing an acid rain program that meets the requirements of Title IV of the CAA.	BAAQMD with EPA Oversight	See Federal, Title 40 CFR, Part 72 to review applicability and the compliance assessment.
BAAQMD Regulation 6 (Particulate Matter and Visible Emissions)	Purpose of this Regulation is to limit the quantity of particulate matter in the atmosphere through the establishment of limitations on emission rates, concentration, visible emissions, and opacity.	BAAQMD	Exhaust emissions shall not be darker than No. 1 when compared to the Ringleman Chart for any period(s) aggregating 3 minutes in any hour, exceed the opacity standard of not greater than 20 percent for a period or periods aggregating 3 minutes in any hour, or exceed the 0.15 grains per dry standard cubic feet of exhaust gas volume. The use of clean fuels (natural gas and California certified low sulfur diesel fuel will insure compliance with these limits.
BAAQMD Regulation 7 (Odorous Substances)	The purpose of this regulation is to place general limitations on odorous substances and specific emission limitations on certain odorous compounds.	BAAQMD	Emissions of odorous substances shall not remain odorous after dilution with odor-free air at a rate of 1,000 volumes of odor-free air per volume of source sample. The maximum emissions of ammonia shall not exceed 5,000 ppm. Ammonia emissions from the SCR catalyst will be less than 5 ppmv. Therefore, maximum emissions will be below the 5,000 ppm limit, and odors from the OGS are expected to be less than significant.
BAAQMD Regulation 9, Rule 1	Establishes emission limits for sulfur dioxide from all sources and limits ground-level concentrations of SO_2	BAAQMD	Dispersion modeling will be conducted to determine if off-property SO_2 ground level concentrations are less than 0.5 ppm for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Sulfur contents in the fuel will be less than 0.5% and gas stream concentrations will be less than 300 ppm (dry).
BAAQMD Regulation 9, Rule 9	Purpose of this rule is to limit emissions of NO_x from stationary gas turbines.	BAAQMD	For turbines with a heat input rating greater than 500 million British thermal units per hour (MMBtu/hr) (40+ MW), NO_x emission levels shall not exceed 0.72 lb/MW-hr or 25 ppmv. BACT levels of less than 2.5 ppmv for NO_x will be applied to the project site; therefore, the NO_x emission levels for the project site will not exceed the 25 ppmv level.

TABLE 5.1-28
Applicable Laws, Ordinances, Regulations, and Standards for Protection of Air Quality

LORS	Purpose	Regulating Agency	Applicability/Compliance Strategy
BAAQMD Regulation 10 (40 CFR Part 60)	Establishes national standards of performance for new or modified facilities in specific source categories.	BAAQMD	See Federal, Title 40 CFR, Part 60 to review applicability and the compliance assessment.

5.1.7 Agencies and Agency Contacts

Table 5.1-28 presents data on the following: (1) air quality agencies that may or will exercise jurisdiction over air quality issues resulting from the power facility, (2) the most appropriate agency contact for the project site, (3) contact address and phone information, and (4) the agency involvement in required permits or approvals.

TABLE 5.1-28
Agencies, Contacts, Jurisdictional Involvement, Required Permits For Air Quality

Agency	Contact	Jurisdictional Area	Permit Status
California Energy Commission (CEC)	Assigned Project Manager 1516 Ninth St. Sacramento, CA 95814	Primary reviewing and certification agency.	Will certify the facility under the energy siting regulations and CEQA. Certification will contain a variety of conditions pertaining to emissions and operation.
Bay Area AQMD	Brian Bateman Dir. Engineering Div. 939 Ellis St. San Francisco, CA 94109 (415) 771-4653	Prepares Determination of Compliance (DOC) for CEC, Issues BAAQMD Authority to Construct (ATC) and Permit to Operate (PTO), Primary air regulatory and enforcement agency.	DOC will be prepared subsequent to AFC submittal. AFC plus District permit forms in Appendix 5.1I comprise the required District application.
California Air Resources Board (CARB)	Mike Tollstrup Chief, Project Assessment Branch 1001 I St., 6th Floor Sacramento, CA 95814 (916) 322-6026	Oversight of AQMD stationary source permitting and enforcement program	CARB staff will provide comments on applicable AFC sections affecting air quality and public health. CARB staff will also have opportunity to comment on draft PTC.
Environmental Protection Agency, Region IX	Gerardo Rios Chief, Permits Section USEPA-Region 9 75 Hawthorne St. San Francisco, CA 94105 (415) 947-3974	Oversight of all AQMD programs, including permitting and enforcement programs	USEPA Region 9 staff will receive a copy of the DOC. USEPA Region 9 staff will have opportunity to comment on draft PTC

5.1.8 Permits and Permit Schedule

An ATC application is required in accordance with the BAAQMD rules. Appendix 5.1-I contains the BAAQMD permitting application forms. These forms in conjunction with the AFC in its entirety, but specifically Section 2.0, Project Description; Section 5.1, Air Quality; Section 5.9, Public Health’ and Appendixes 5.1-A through 5.1-I constitute the required Authority to Construct application pursuant to the District rules.

5.1.9 References

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ATTACHMENT B

Revised AFC Section 5.9, Public Health

5.9 Public Health

This section presents the methodology and results of a human Health Risk Assessment (HRA) performed to assess potential effects and public exposure associated with airborne emissions from the routine operation of the Contra Costa Generating Station (CCGS or project). Section 5.9.1 describes the affected environment. Section 5.9.2 discusses the environmental consequences from the operation of the power facility and associated facilities. Section 5.9.3 discusses cumulative effects. Section 5.9.4 discusses mitigation measures. Section 5.9.5 presents applicable laws, ordinances, regulations, and standards (LORS). Section 5.9.6 provides permit requirements, schedules, and Section 5.9.7 lists agency contacts. Section 5.9.8 contains references cited or consulted in preparing this section.

The Applicant is proposing to construct and operate a nominal 624-megawatt (MW) combined-cycle, combustion turbine based electrical generating facility in Contra Costa County, California. The proposed new turbine installation will be constructed on the existing DuPont facility site in Oakley.

Air will be the dominant pathway for public exposure to chemical substances released by the Project. Emissions to the air will consist primarily of combustion byproducts from the new combustion turbines and the proposed fire pump engine. Potential health risks from combustion emissions will occur almost entirely by direct inhalation. To be conservative, additional pathways were included in the health risk modeling; however, direct inhalation is considered the most likely exposure pathway. The HRA was conducted in accordance with guidance established by the California Office of Environmental Health Hazard Assessment (OEHHA) and the California Air Resources Board (CARB) (OEHHA/CARB, 2003).

Combustion byproducts with established California Ambient Air Quality Standards (CAAQS) or National Ambient Air Quality Standards (NAAQS), including nitrogen oxides (NO_x), carbon monoxide (CO), and fine particulate matter (PM_{10}/$PM_{2.5}$) are addressed in Section 5.1, Air Quality. However, some discussion of the potential health risks associated with these substances is presented in this section. Human health risks associated with the potential accidental release of stored hazardous materials are discussed in Section 5.5, Hazardous Materials Handling.

5.9.1 Affected Environment

The project site is on 21.95 acres located within the boundary of an existing 210-acre site owned by DuPont. CCGS holds an option to purchase the 21.95-acre site, and DuPont is currently proceeding with a lot line adjustment to separate the site from the larger 210-acre parcel. The site is currently zoned “heavy industrial,” with surrounding land uses comprised of industrial, vacant industrial, commercial, and agricultural. The City of Oakley is revising its zoning regulations to match its 2020 General Plan. The site zoning will change from “heavy industrial” to “utility energy” land use, with the reminder of the DuPont site classified as “business park” or “light industrial.”

The site is bounded to the west by the Pacific Gas and Electric Company’s (PG&E) Antioch Terminal, a large natural gas transmission hub; to the north by DuPont property that is industrial and vacant industrial; to the east by DuPont’s titanium dioxide landfill area; and to the south by the Atchison, Topeka, and Santa Fe railroad. Immediately south of the railroad is a large parcel currently in agriculture. A 74.6-acre commercial development, the Rivers Oaks Crossing, has been proposed for this parcel.

The site elevation is approximately 32 feet above mean sea level. Because the site is in the existing DuPont property boundary, the project site and surrounding areas are highly developed, and have been subject to disturbance for many years.

The site Universal Transverse Mercator (UTM) coordinates are 610177 meters easting, 4207415 meters northing, Zone 10 (NAD27).

The site is in census tract 3020.03. Figures 5.1D-1, Sensitive Receptor Map, and 5.1D-2, Census Tracts in the Immediate Impact Area (Appendix 5.1D) show the site, sensitive receptor locations, and surrounding census tracts. The Census Findings table (Appendix 5.1D) presents a summary of data for each identified census tract adjacent to the site.

Sensitive receptors are defined as groups of individuals that may be more susceptible to health risks from chemical exposure. Public and private schools, day care facilities, convalescent homes, and hospitals are of particular concern. Appendix 5.1D presents a detailed listing of near-field sensitive receptors. The nearest sensitive receptors based on receptor type are listed in Table 5.9-1. Appendix 5.1D provides data on the population by census tract.

TABLE 5.9-1
Nearest Sensitive Receptors By Receptor Type

Receptor ID	Receptor Type	UTM Coordinates (E/N), meters
Nearest Residence-1	Residence	611203, 4207655
Nearest Residence-2	Residence	610938, 4207390
Nearest School	School	612604, 4206870
Nearest Hospital	Hospital	604974, 4204348
Nearest Daycare	Daycare Center	N/A
Nearest Convalescent Home	Convalescent Home	N/A
Nearest Worker (offsite)	Offsite Worker	610323, 4207564

Note:
N/A = indicates no such receptor type in the near-field radius of 2-3 miles.

Source: All coordinates from Google Earth (center location of each receptor location), converted to NAD27.

Air quality and health risk data presented by CARB in the 2008 Almanac of Emissions and Air Quality for the state shows that from 1990 through 2008 the average concentrations for the top 10 toxic air contaminants (TACs) have been substantially reduced, and the associated health risks for the state are showing a steady downward trend. This same trend is expected to have occurred in the San Francisco Bay Area Air Basin (SFBAAB). CARB-estimated emissions inventory values for the top 10 TACs for 2007 to 2008 are presented in Table 5.9-2.

TABLE 5.9-2
Top 10 Toxic Air Contaminants for the SFBAAB

TAC	SFBAAB Year 2008 Emissions (tons/yr)	Annual Average Concentration[1], 2007	Predicted Cancer Risk[1], per 10^6, 2007
Acetaldehyde	9103	0.56 ppb	3
Benzene	10794	0.274 ppb	25
1,3 Butadiene	3754	0.06 ppb	23
Carbon tetrachloride	4.04	ND	ND
Chromium 6	0.61	0.053 $\mu g/m^3$	8
Para-Dichlorobenzene	1508	ND	ND
Formaldehyde	20951	1.45 ppb	11
Methylene Chloride	6436	0.13 ppb	<1
Perchloroethylene	4982	0.031 ppb	1
Diesel PM	35884	ND	ND

Source: CARB, 2009a

5.9.2 Environmental Consequences

5.9.2.1 Significance Criteria

5.9.2.1.1 Cancer Risk

Cancer risk is the probability or chance of contracting cancer over a human life span (assumed to be 70 years). Carcinogens are not assumed to have a threshold below which there would be no human health effect. In other words, any exposure to a carcinogen is assumed to have some probability of causing cancer; the lower the exposure, the lower the cancer risk (that is, a linear, no-threshold model). Under various state and local regulations, an incremental cancer risk greater than 10 in a million from a project is considered to be a significant effect on public health. For example, the 10 in a million risk level is used by the Air Toxics Hot Spots (AB 2588) program and California's Proposition 65 as the public notification level for air toxic emissions from existing sources.

5.9.2.1.2 Non-Cancer Risk

Non-cancer health effects can be classified as either chronic or acute. In determining the potential health risks of non-cancerous air toxics, it is assumed there is a dose of the chemical of concern below which there would be no effect on human health. The air concentration corresponding to this dose is called the Reference Exposure Level (REL). Non-cancer health risks are measured in terms of a hazard quotient, which is the calculated exposure of each contaminant divided by its REL. Hazard quotients for pollutants affecting the same target organ are typically summed with the resulting totals expressed as hazard indices for each organ system. A hazard index of less than 1.0 is considered to be an insignificant health risk. For this HRA, all hazard quotients were summed regardless of target organ. This method leads to a conservative, upper-bound assessment. RELs used in the hazard index calculations were those published in the CARB/OEHHA listings (CARB, 2009b).

Chronic toxicity is defined as adverse health effects from prolonged chemical exposure, caused by chemicals accumulating in the body. Because chemical accumulation to toxic levels typically occurs slowly, symptoms of chronic effects usually do not appear until long after exposure commences. The lowest no-effect chronic exposure level for a non-carcinogenic air toxic is the chronic REL. Below this threshold, the body is capable of eliminating or detoxifying the chemical rapidly enough to prevent its accumulation. The chronic hazard index was calculated using the hazard quotients calculated with annual concentrations.

Acute toxicity is defined as adverse health effects caused by a brief chemical exposure of no more than 24 hours. For most chemicals, the air concentration required to produce acute effects is higher than the level required to produce chronic effects because the exposure duration is shorter. Because acute toxicity is predominantly manifested in the upper respiratory system at threshold exposures, all hazard quotients are typically summed to calculate the acute hazard index. One-hour average concentrations are divided by acute RELs to obtain a hazard index for health effects caused by relatively high, short-term exposure to air toxics.

5.9.2.2 Construction Phase Effects

The construction phase is expected to take approximately 33 months (followed by several months of startup and commissioning). No significant public health effects are expected during the construction phase. Strict construction practices that incorporate safety and compliance with applicable LORS will be followed (see Section 5.9.5). Additionally, mitigation measures to reduce air emissions from construction effects will be implemented as described in Section 5.1, Air Quality.

Temporary emissions from construction-related activities are discussed in Section 5.1, Air Quality. Ambient air modeling for particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), CO, sulfur dioxide (SO_2), and NO_x was performed as described in Section 5.1, Air Quality. Construction-related emissions are temporary and localized, resulting in no long-term effects to the public.

Small quantities of hazardous waste may be generated during the construction phase of the Project. Hazardous waste management plans will be in place so the potential for public exposure is minimal. Refer to Section 5.14, Waste Management, for more information. No acutely hazardous materials will be used or stored onsite during construction (see Section 5.5, Hazardous Materials Handling). To ensure worker safety during construction, safe work practices will be followed (Section 5.16, Worker Safety).

5.9.2.3 Operational Phase Effects

Environmental consequences potentially associated with the operation of the project are potential human exposure to chemical substances emitted to the air. The human health risks potentially associated with these chemical substances were evaluated in an HRA. The chemical substances potentially emitted to the air from the project turbine/heat recovery steam generator (HRSG), auxiliary boiler, fire pump engine, and cooling tower cells are listed in Table 5.9-3.

TABLE 5.9-3
Chemical Substances Potentially Emitted to the Air from the Project

Criteria Pollutants
Particulate Matter
Carbon Monoxide
Sulfur Oxides
Nitrogen Oxides
Volatile Organic Compounds
Lead
Noncriteria Pollutants (Toxic Pollutants)
Ammonia
Polycyclic Aromatic Hydrocarbons (PAHs)
Acetaldehyde
Acrolein
Benzene
1-3 Butadiene
Ethylbenzene
Formaldehyde
Hexane (n-Hexane)
Naphthalene
Propylene
Propylene Oxide
Toluene
Xylene
Arsenic
Aluminum
Cadmium
Chromium VI
Copper
Iron
Mercury
Manganese
Nickel
Silver
Zinc
Diesel PM

Emissions of criteria pollutants will adhere to NAAQS and CAAQS as discussed in Section 5.1, Air Quality. The project also will include emission control technologies necessary to meet the required emission standards specified for criteria pollutants under Bay Area Air Quality Management District (BAAQMD) rules. Offsets will be required because the project will be a new major source. Finally, air dispersion modeling results (presented in Section 5.1, Air Quality) show that emissions will not result in concentrations of criteria pollutants in air that would cause exceedances of ambient air quality standards (either NAAQS or CAAQS) or applicable significance thresholds. These standards are intended to protect the general public with a wide margin of safety. Therefore, the project is not anticipated to have a significant effect on public health from emissions of criteria pollutants.

The project operational phase, as currently evaluated, will emit HAP emissions in excess of the EPA/BAAQMD major source thresholds of 10 tons per year for a single pollutant (formaldehyde), and 25 tons per year for all pollutants combined. Potential effects associated with emissions of toxic pollutants to the air from the project were addressed in an HRA, presented in Appendix 5.1D. The HRA was prepared using guidelines developed by OEHHA and CARB, as implemented in the latest version of the Hotspots Analysis and Reporting Program (HARP) model (Version 1.4a)(HARP.2003). As an input into HARP, the HARP On-Ramp preprocessor (as compiled by CARB on February 3, 2009) was used to convert the AERMOD model output into a suitable format for HARP (HARP.2004).

5.9.2.4 Public Health Effect Study Methods

Emissions of toxic pollutants potentially associated with the project were estimated using emission factors approved by CARB and the U.S. Environmental Protection Agency (EPA). Concentrations of these pollutants in air potentially associated with project emissions were estimated using the HARP dispersion modeling module. Modeling allows the estimation of short- and long-term average concentrations in air for use in an HRA, accounting for site-specific terrain and meteorological conditions. Health risks potentially associated with the estimated concentrations of pollutants in the air were characterized in terms of excess lifetime cancer risks (for carcinogenic substances), or comparison with reference exposure levels for non-cancer health effects (for non-carcinogenic substances).

Health risks were evaluated for a hypothetical maximum exposed individual (MEI) located at the maximum impact receptor (MIR). The hypothetical MEI is an individual assumed to be at the MIR location, which is assumed to be a residential receptor where the highest concentrations of air pollutants associated with project emissions are predicted to occur, based on the air dispersion modeling. Human health risks associated with emissions from the project are unlikely to be higher at any other location than at the location of the MIR. If there is no significant effect associated with concentrations in air at the MIR location, it is unlikely that there would be significant effects in any location in the vicinity of the project. The highest concentration location represents the MIR.

Health risks potentially associated with concentrations of carcinogenic air pollutants were calculated as estimated excess lifetime cancer risks. The excess lifetime cancer risk for a pollutant is estimated as the product of the concentration in air and a unit risk value. The unit risk value is defined as the estimated probability of a person contracting cancer as a result of constant exposure to an ambient concentration of 1 microgram per cubic meter ($\mu g/m^3$) over a 70-year lifetime. In other words, it represents the increased cancer risk associated with continuous exposure to a concentration in the air over a 70-year lifetime. Evaluation of potential non-cancer health effects from exposure to short- and long-term concentrations in the air was performed by comparing modeled concentrations in air with the RELs. An REL is a concentration in the air at or below which no adverse health effects are anticipated. RELs are based on the most sensitive adverse effects reported in the medical and toxicological literature. Potential non-cancer effects were evaluated by calculating a ratio of the modeled concentration in the air and the REL. This ratio is referred to as a hazard quotient. The unit risk values and RELs used to characterize health risks associated with modeled concentrations in the air were obtained from the Consolidated Table of OEHHA/CARB Approved Risk Assessment Health Values (CARB, 2009b), and are presented in Table 5.9-4.

TABLE 5.9-4
Toxicity Values Used to Characterize Health Risks (Inhalation)

Compound	Unit Risk Factor $(\mu g/m^3)^{-1}$	Chronic Reference Exposure Level $(\mu g/m^3)$	Acute Reference Exposure Level $(\mu g/m^3)$
Ammonia	-	200	3,200
Acetaldehyde	0.0000027	140	470
Acrolein	-	0.35	2.5
Benzene	0.000029	60	1,300
1-3 Butadiene	0.00017	20	-
Ethylbenzene	0.0000025	2,000	-
Formaldehyde	0.000006	9	55
Hexane	-	7,000	-
Naphthalene	0.000034	9	-
PAHs (as BaP)	0.0011	-	-
Propylene	-	3,000	-
Propylene Oxide	.0000037	30	3,100
Toluene	-	300	37,000
Xylene	-	700	22,000
Arsenic	0.0033	0.015	0.20
Aluminum	-	-	-
Cadmium	0.0042	0.02	-
Chromium VI	0.15	0.2	-
Copper	-	-	100
Iron	-	-	-
Lead	0.000012	-	-
Mercury	-	0.03	0.6
Manganese	-	0.09	-
Nickel	0.00026	0.05	6
Silver	-	-	-
Zinc	-	-	-
Diesel PM	0.0003	5	-

Source: CARB, 2009b.

There were no identified or available health studies through the local public health department concerning the potentially affected population(s) within a 6-mile radius of the proposed power plant site related to respiratory illnesses, cancers, or related diseases.

Emissions of the various toxic and/or hazardous air pollutants are detailed in Appendix 5.1A.

5.9.2.5 Characterization of Risks from Toxic Air Pollutants

Based on 8,463 hours of operation, the excess lifetime cancer risk associated with concentrations in air estimated for the project MIR location is estimated to be 3.50×10^{-6}.

Excess lifetime cancer risks less than 1 x 10^{-6} are unlikely to represent significant public health effects that require additional controls of facility emissions. Risks higher than 1 x 10^{-6} may or may not be of concern, depending upon several factors. These include the conservatism of assumptions used in risk estimation, size of the potentially exposed population, and toxicity of the risk-driving chemicals. Health effects risk thresholds are listed in Table 5.9-5. Risks associated with pollutants potentially emitted from the Project are presented in Table 5.9-6. Further description of the methodology used to calculate health risks associated with emissions to the air is presented in Appendix 5.1D. As described previously, human health risks associated with emissions from the project are unlikely to be higher at any other location than at the location of the MIR. If there is no significant effect associated with concentrations in air at the MIR location, it is unlikely that there would be significant effects in any other location in the project vicinity.

TABLE 5.9-5
Health Effects Significant Threshold Levels for BAAQMD

Risk Category	Risk Threshold
Cancer Risk	1 per million without T-BACT 10 per million with T-BACT
Acute Hazard Index	<= 1.0
Chronic Hazard Index	<= 1.0
Cancer Burden	N/A

Notes:
N/A = not applicable in the BAAQMD
T-BACT = Toxic Best Available Control Technology

Source: BAAQMD Regulation 2, Rule 5.

Cancer risks potentially associated with facility emissions also were assessed in terms of cancer burden. Cancer burden is a hypothetical upper-bound estimate of the additional number of cancer cases that could be associated with emissions from the project. Cancer burden is calculated as the worst-case product of excess lifetime cancer risk and the number of individuals at that risk level. Application of the MIR cancer risk to the entire population of census tract 3020.03 results in an overly conservative estimate of cancer burden. The calculated cancer burden for the project is ~0.033.

TABLE 5.9-6
Project HRA Summary

	Turbines/HRSGs, Auxiliary Boiler, Fire Pump, and Cooling Tower	
Risk Category	**Project Values**	**Applicable Significance Threshold**
Cancer Risk	3.50 x 10^{-6}	10.0 X 10^{-6} with T-BACT
Chronic Hazard Index	0.021	1.0
Acute Hazard Index*	0.0807	1.0
Cancer Burden	0.033	N/A

[1] MIR effect area lies in Tract 3020.03, with a total population of ~10231.

TABLE 5.9-6
Project HRA Summary

	Turbines/HRSGs, Auxiliary Boiler, Fire Pump, and Cooling Tower	
Risk Category	**Project Values**	**Applicable Significance Threshold**

*at the maximum acute impact receptor.

Notes:
N/A = not applicable in the BAAQMD
T-BACT = Toxic Best Available Control Technology

Source: Radback Energy CCGS Team, 2009.

A detailed listing and map of affected census tracts and year 2000 population estimates are provided in Appendix 5.1D, Public Health.

As described previously, human health risks associated with project emissions are unlikely to be higher at any other location than at the MIR. Therefore, the risks for all of these individuals would be lower (and in most cases, substantially lower) than 3.50×10^{-6}. The estimated cancer burden was ~0.033, indicating that emissions from the project would not be associated with any increase in cancer cases in the previously defined population. Additionally, the cancer burden is less than the California threshold value. The methods used in this calculation considerably overstate the potential cancer burden, further suggesting that project emissions are unlikely to represent a significant public health effect in terms of cancer risk. Risk results for all of the identified nearfield sensitive receptors were well below the MIR values noted above.

The acute non-cancer hazard quotient associated with concentrations in air is shown in Table 5.9-6. The acute non-cancer hazard quotients for all target organs fall below 1.0. A hazard quotient less than 1.0 is unlikely to represent significant effect to public health. Further description of the methodology used to calculate health risks associated with emissions to the air is presented in Appendix 5.1D. Human health risks associated with project emissions are unlikely to be higher at any other location than at the MIR. If there is no significant effect associated with concentrations in the air at the MIR location, it is unlikely that there would be significant effects in any other location in the project vicinity.

Detailed risk and hazard values are provided in the HARP output presented in Appendix 5.1D.

The estimates of excess lifetime cancer risks and non-cancer risks associated with chronic or acute exposures fall below thresholds used for regulating emissions of toxic pollutants to the air. Historically, exposure to any level of a carcinogen has been considered to have a finite risk of inducing cancer. In other words, there is no threshold for carcinogenicity. Because risks at low levels of exposure cannot be quantified directly by either animal or epidemiological studies, mathematical models have estimated such risks by extrapolation from high to low doses. This modeling procedure is designed to provide a highly conservative estimate of cancer risks based on the most sensitive species of laboratory animal for extrapolation to humans. In other words, the assumption is that humans are as sensitive as the most sensitive animal species. Therefore, the true risk is not likely to be higher than risks estimated using unit risk factors and is most likely lower, and could even be zero.

An excess lifetime cancer risk of 1 x 10^{-6} is typically used as a screening threshold of significance for potential exposure to carcinogenic substances in air. The excess cancer risk level of 1 x 10^{-6}, which has historically been judged to be an acceptable risk, originates from efforts by the Food and Drug Administration to use quantitative HRA for regulating carcinogens in food additives in light of the zero tolerance provision of the Delany Amendment (Hutt, 1985). The associated dose, known as a "virtually safe dose," has become a standard used by many policy makers and the lay public for evaluating cancer risks. However, a study of regulatory actions pertaining to carcinogens found that an acceptable risk level can often be determined on a case-by-case basis. This analysis of 132 regulatory decisions, found that regulatory action was not taken to control estimated risks below 1 x 10^{-6} (one in a million), which are called de minimis risks. De minimis risks are historically considered risks of no regulatory concern. Chemical exposures with risks above 4 x 10^{-3}, called de manifestis risks, were consistently regulated. De manifestis risks are typically risks of regulatory concern. The risks falling between these two extremes were regulated in some cases, but not in others (Travis et al., 1987).

The estimated lifetime cancer risks to the maximally exposed individual located at the project MIR are well below the 10 x 10^{-6} significance level, and the aggregated cancer burden associated this risk level is less than 1.0 excess cancer case. Additionally, the cancer burden is less than the California threshold value. These risk estimates were calculated using assumptions that are highly health conservative. Evaluation of the risks associated with project emissions should consider that the conservatism in the assumptions and methods used in risk estimation considerably overstates the risks. Based on the results of this HRA, there are no significant public health effects anticipated from emissions of toxic pollutant to the air from the project.

5.9.2.6 Hazardous Materials

Hazardous materials will be used and stored at the project site. The hazardous materials stored in significant quantities onsite and descriptions of their uses are presented in Section 5.5, Hazardous Materials Handling. Use of chemicals at the project site will be in accordance with standard practices for storage and management of hazardous materials. Normal use of hazardous materials, therefore, will not pose significant effects to public health. While mitigation measures will be in place to prevent releases, accidental releases that migrate off-site could result in potential effects to the public.

The California Accidental Release Program regulations (CalARP) and Code of Federal Regulations (CFR) Title 40 Part 68 under the Clean Air Act establish emergency response planning requirements for specific hazardous materials. These regulations require preparation of a Risk Management Plan (RMP), which is a comprehensive program to identify hazards and predict the areas that may be affected by a release of a program listed hazardous material. Any RMP-listed materials proposed to be used at the project are discussed in Section 5.5, Hazardous Materials Handling.

5.9.2.7 Operation Odors

The project is not expected to emit or cause to be emitted any substances that could cause odors.

5.9.2.8 Electromagnetic Field Exposure

Electromagnetic fields (EMFs) occur independently of one another as electric and magnetic fields at the 60- Hertz frequency used in transmission lines, and both are created by electric charges. Electric fields exist when these charges are not moving. Magnetic fields are created when the electric charges are moving. The magnitude of both electric and magnetic fields falls off rapidly as the distance from the source increases (proportional to the inverse of the square of distance).

Because the electric transmission line does not travel through residential areas, and based on recent findings of the National Institute of Environmental Health Sciences (NIEHS, 1999), EMF exposures are not expected to result in a significant effect on public health. The NIEHS report to the U.S. Congress found that "the probability that EMF exposure is truly a health hazard is currently small. The weak epidemiological associations and lack of any laboratory support for these associations provide only marginal scientific support that exposure to this agent is causing any degree of harm" (NIEHS, 1999).

California does not have a regulatory level for magnetic fields. However, the values estimated for the project are well below those established by states that do have limits. Other states have established regulations for magnetic field strengths that have limits ranging from 150 milligauss to 250 milligauss at the edge of the right-of-way, depending on voltage. The California Energy Commission does not specify limits on magnetic fields for 230-kilovolt transmission lines.

5.9.2.9 Legionella

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling tower cells, including *Legionella*. *Legionella* is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in human-made water systems. It is the principal cause of legionellosis, otherwise known as Legionnaires' disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling tower cells and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionellosis.

Legionella can grow symbiotically with other bacteria and can infect protozoan hosts. This provides *Legionella* with protection from adverse environmental conditions, including making it more resistant to water treatment with chlorine, biocides, and other disinfectants. Thus, if not properly maintained, cooling water systems and their components can amplify and disseminate aerosols containing *Legionella*.

The State of California regulates recycled water for use in cooling tower cells in Title 22, Section 60303, California Code of Regulations. This section requires that chlorine or another biocide must be used to treat the cooling system water to minimize the growth of *Legionella* and other microorganisms to protect workers and the public who may come into contact with cooling tower mists.

The EPA published an extensive review of *Legionella* in a human health criteria document (EPA, 1999). The EPA noted that *Legionella* may propagate in biofilms (collections of microorganisms surrounded by slime they secrete, attached to either inert or living surfaces) and that aerosol-generating systems, such as cooling tower cells, can aid in the transmission of *Legionella* from water to air. The EPA has inadequate quantitative data on the infectivity of *Legionella* in humans to prepare a dose-response evaluation. Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of *Legionella*. Thus, the presence of even small numbers of *Legionella* bacteria presents a risk, however small, of disease in humans.

In 2000, the Cooling Tower Institute (CTI) issued its own report and guidelines for the best practices for control of *Legionella* (CTI, 2000). The CTI found that 40 to 60 percent of industrial cooling tower cells tested were found to contain *Legionella*. The CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling tower cells, and the overall general control of microbiological populations. Good preventive maintenance is important for the efficient operation of cooling tower cells and other evaporative equipment (ASHRAE, 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. The efficacy of any biocide in ensuring that bacteria, and in particular *Legionella* growth, is kept to a minimum is contingent on several factors, including proper dosage amounts, appropriate application procedures, and effective monitoring.

To ensure that *Legionella* growth is kept to a minimum, thereby protecting nearby workers and the public, an appropriate biocide program and anti-biofilm agent monitoring program would be prepared and implemented for the entire cooling tower, including the two new cooling tower cells associated with this project. These programs would ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. The mitigation measure presented in Section 5.9.4 would reduce to insignificant the chances of *Legionella* growing and dispersing (Risk Science Associates, 2008).

5.9.2.10 Summary of Effects

Results from the air toxics HRA based on emissions modeling indicate that there will be no significant incremental public health risks from construction or operation of the project. Results from criteria pollutant modeling for routine operations indicate that potential ambient concentrations of NO_2, CO, SO_2, and PM_{10} will not significantly affect air quality (Section 5.1, Air Quality). Potential concentrations are below the federal and California standards established to protect public health, including the more sensitive members of the population.

5.9.3 Cumulative Effects

The HRA for the project indicates that the maximum cancer risk will be approximately 3.50×10^{-6}, versus a significance threshold of 10.0 in 1 million with T-BACT at the point of maximum exposure to air toxics from power facility emissions. This risk level is considered to be insignificant. Non-cancer chronic and acute effects also will be less than significant. Therefore, the risk of effects from the project combining with effects from other past, present, and reasonably foreseeable future projects to make a significant effect are also very low. A cumulative health risk effect analysis is not proposed at this time because of the low emissions and low risks from the project.

5.9.4 Mitigation Measures

5.9.4.1 Criteria Pollutants

Emissions of criteria pollutants will be minimized by applying Best Available Control Technology (BACT) to the project. BACT for the turbines/HRSGs, auxiliary boiler, fire pump, and new evaporative condenser cells is discussed in Appendix 5.1F.

The project location is in an area that is designated by the federal air agencies as non-attainment for ozone and particulate matter. Pursuant to BAAQMD New Source Review Rule, offsets are required for the project. Therefore, further mitigation of emissions is not required to protect public health.

5.9.4.2 Toxic Pollutants

Emissions of toxic pollutants to the air will be minimized through the use of BACT/T-BACT.

5.9.4.2.1 Legionella Mitigation Measure

The Applicant will develop and implement a Cooling Water Management Plan to ensure that the potential for bacterial growth in cooling water is kept to a minimum. The plan will be consistent with the CTI's "Best Practices for Control of *Legionella*" guidelines and will include sampling and testing for the presence of *Legionella* bacteria at appropriate intervals (Risk Science Associates, 2008).

5.9.4.3 Hazardous Materials

Mitigation measures for hazardous materials are presented below and discussed in more detail in Section 5.5, Hazardous Materials Handling. Potential public health effects from the use of hazardous materials are only expected to occur as a result of an accidental release. The facility has many safety features designed to prevent and minimize effects from the use and accidental release of hazardous materials. The project site will include the design features listed below.

- Curbs, berms, and/or secondary containment structures will be provided where accidental release of chemicals may occur.
- A fire-protection system will be included to detect, alarm, and suppress a fire in accordance with applicable LORS.
- Construction of all storage systems will be in accordance with applicable construction standards and LORS.

If required, a RMP for the facility will be prepared prior to commencement of operations. The RMP will estimate the risk presented by handling affected materials at the site. The RMP will include a hazard analysis, offsite consequence analysis, seismic assessment, emergency response plan, and training procedures. The RMP process will accurately identify and propose adequate mitigation measures to reduce the risk to the lowest possible level.

A safety program will be implemented and will include safety training programs for contractors and operations personnel, including instructions on the proper use of personal protective equipment, safety operating procedures, fire safety, and emergency response actions. The safety program also will include programs on safely operating and maintaining systems that use hazardous materials. Emergency procedures for personnel include power facility evacuation, hazardous material spill cleanup, fire prevention, and emergency response.

Areas subject to potential leaks of hazardous materials will be paved and bermed. Incompatible materials will be stored in separate containment areas. Containment areas will be drained to either a collection sump or to holding or neutralization tanks. Also, piping and tanks exposed to potential traffic hazards will be additionally protected by traffic barriers.

5.9.5 Laws, Ordinances, Regulations, and Standards

An overview of the regulatory process for public health issues is presented in this section. The relevant LORS that affect public health and are applicable to the project are identified in Table 5.9-7. The conformity of the project with each of the LORS applicable to public health is also presented in this table, with references to the sections in this report where each of these issues is addressed. Table 5.9-7 also lists the primary agencies responsible for public health and the general category of the public health concern regulated by each.

TABLE 5.9-7
Summary of LORS – Public Health

LORS	Applicability	Primary Regulatory Agency	Project Conformance	Conformance (AFC Section)
Federal Clean Air Act Title III	Public exposure to air pollutants	EPA Region 9 CARB BAAQMD	Based on results of HRA as per CARB/OEHHA guidelines, toxic contaminants do not exceed acceptable levels. Emissions of criteria pollutants will be minimized by applying BACT to the Project.	Section 5.9, and Appendix 5.1D
Health and Safety Code 25249.5 et seq. (Safe Drinking Water and Toxic Enforcement Act of 1986—Proposition 65)	Public exposure to chemicals known to cause cancer or reproductive toxicity	OEHHA	Based on results of HRA as per CARB/OEHHA guidelines, toxic contaminants do not exceed thresholds that require exposure warnings.	Section 5.9, and Appendix 5.1D

TABLE 5.9-7
Summary of LORS – Public Health

LORS	Applicability	Primary Regulatory Agency	Project Conformance	Conformance (AFC Section)
40 CFR Part 68 (Risk Management Plan) and CalARP Program Title 19	Public exposure to specific hazardous materials	EPA Region 9 Contra Costa County Department of Health Services	A vulnerability analysis will be performed to assess potential risks from a spill or rupture from any affected storage tank. An RMP (if required) will be prepared prior to commencement of Project operations.	Section 5.9, and Appendix 5.1D, Section 5.5
California Health and Safety Code (CHSC) Sections 25531 to 25541	Public exposure to specific hazardous materials	Contra Costa County Department of Health Services CARB BAAQMD	A vulnerability analysis will be performed to assess potential risks from a spill or rupture from any affected storage tank.	Section 5.5
CHSC 25500-25542	Hazmat Inventory	State Office of Emergency Services and Contra Costa County Department of Environmental Health	Prepare all required hazardous material plans and inventories, distribute to affected agencies	Section 5.5
CHSC 44300 et seq.	AB2588 Air Toxics Program	BAAQMD	Participate in the AB2588 inventory and reporting program at the District level.	Section 5.9, and Appendix 5.1D
BAAQMD Regulation 2, Rule 5	Toxics New Source Review	BAAQMD	Application of BACT and T-BACT, preparation of HRA	Section 5.9, and Appendix 5.1D
CHSC 25249.5	Proposition 65	OEHHA	Comply with all signage and notification requirements.	Section 5.5
Health and Safety Code Sections 44360 to 44366 (Air Toxics “Hot Spots” Information and Assessment Act—AB 2588)	Public exposure to toxic air contaminants	CARB BAAQMD	Based on results of HRA as per CARB/OEHHA guidelines, toxic contaminants do not exceed acceptable levels.	Section 5.9, and Appendix 5.1D

5.9.6 Permits Required and Schedule

Agency-required permits related to public health include an RMP and BAAQMD Permit to Construct/Permit to Operate. These requirements are discussed in Section 5.5, Hazardous Materials Handling, and Section 5.1, Air Quality, respectively.

5.9.7 Agencies Involved and Agency Contacts

Table 5.9-8 provides contact information for agencies involved with public health.

TABLE 5.9-8
Summary of Agency Contacts for Public Health

Public Health Concern	Primary Regulatory Agency	Regulatory Contact
Public exposure to air pollutants	EPA Region 9	Gerardo Rios Chief, Permits Section EPA-Region 9 75 Hawthorne St. San Francisco, CA 94105 (415) 947-3974
	CARB	Mike Tollstrup 1001 1 Street, 19th Floor Sacramento, CA 95814 (916) 322-6026
	BAAQMD	Brian Bateman Director, Engineering Division 939 Ellis St. San Francisco, Ca. 94109 415-771-4653
Public exposure to chemicals known to cause cancer or reproductive toxicity	OEHHA	Cynthia Oshita or Susan Long P.O. Box 4010 Sacramento, CA 95812-4010 (916) 445-6900
Public exposure to acutely hazardous materials	EPA Region 9	Gerardo Rios Chief, Permits Section EPA-Region 9 75 Hawthorne St. San Francisco, CA 94105 (415) 947-3974
	Contra Costa County Health Services, Hazardous Materials Division	Randy Sawyer Director, Haz Mat Programs 4333 Pacheco Blvd. Martinez, Ca. 94553 (925) 646-2286

Source: Radback Energy CCGS Team, 2009.

5.9.8 References

California Air Resources Board (CARB). 2009a. California Almanac of Emissions and Air Quality – 2009 Edition. Planning and Technical Support Division.

California Air Resources Board (CARB). 2009b. Consolidated table of OEHHA/ARB approved risk assessment health values. (http://arbis.arb.ca.gov/toxics/healthval/contable.pdf)

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HARP. 2004. (Hotspots Analysis and Reporting Program) Express User Manual. Dillingham Software Engineering, Inc., Version 2.07, September 2004.

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OEHHA/CARB (Office of Environmental Health Hazard Assessment/California Air Resources Board). 2003. Air Toxics Hot Spots Program Risk Assessment Guidelines, CalEPA, August 2003. HARP Model, Version 1.4a, Updated July 2008.

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ASHRAE. 1998. American Society of Heating, Refrigeration, and Air Conditioning Engineers. 1998. Legionellosis: Position Paper, June 25.

EPA. 1999. Environmental Protection Agency. Legionella:Human Health Criteria Document. EPA -822-R-99-001. November.

Radback Energy – Contra Costa Generating Station, Project Research Team, 2009.

ATTACHMENT C

Revised Appendixes

APPENDIX 5.1A

Emission Calculations and Support Data

APPENDIX 5.1A

Emissions Calculations and Support Data

Tables presented in this Appendix are as follows:

In addition to the above tables, other miscellaneous support data for the device-specific emissions calculations may also be included in this Appendix.

Table 5.1A-1 Ammonia Slip Emissions

Unit	Lbs/hr	Lbs/Day	Tons/Yr
Turbine/HRSG 1	14.36	344.64	60.66
Turbine/HRSG 2	14.36	344.64	60.66
Aux Boiler	0	0	0

Table 5.1A-2 Fuel Use Estimates

Unit	Per hour	Per Day	Per Yr
Turbine/HRSG 1	2.104 mmscf	50.449 mmscf	17,317.65 mmscf
Turbine/HRSG 2	2.104 mmscf	50.449 mmscf	17,317.65 mmscf
Aux Boiler	0.0495 mmscf	1.176 mmscf	213.90 mmscf
Fire Pump Engine	20 gals	20 gals	1000 gals

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	**Case D**	**Case R**	**Case H**	**Case J**	**Case X**	**Case 01C**	**Case 01F**	**Case 01E**
		Max All Units	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**
Operating Conditions										
Ambient Dry Bulb Temp.	deg. F	59	59	59	104	104	104	34	34	34
Ambient Wet Bulb Temp.	deg. F	51	51	51	70	70	70	32	32	32
Relative Humidity	%	60%	60%	60%	18%	18%	18%	83%	83%	83%
Elevation	ft	21	21	21	21	21	21	21	21	21
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68	14.68
Combustion Turbine Load	%	100%	80%	49%	100%	80%	52%	100%	80%	49%
Combustion Turbines Operating		2	2	1	2	2	1	2	2	1
Evap Cooling or Fogging? (Yes/No)		Yes	No	No	Yes	No	No	No	No	No
Evap Cooling/Fogging Effectiveness	%	85%	%	85%	85%	85%	85%	85%	85%	85%
Duct Firing? (Yes/No)		No	No	No	No	No	No	No	No	No
Steam or Water Injection? (Yes/No)		No	No	No	No	No	No	No	No	No
Fuel Input (each CT)										
Fuel Type		Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CT Fuel (LHV)	MMBtu/hr	1,896	1,562	1,208	1,843	1,433	1,157	1,940	1,734	1,239
HRSG Fuel (LHV)	MMBtu/hr	0	0	0	0	0	0	0	0	0
Total Fuel (LHV)	MMBtu/hr	1,896	1,562	1,208	1,843	1,433	1,157	1,940	1,734	1,239
HHV/LHV =		1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085	1.1085
CT Fuel (HHV)	MMBtu/hr	2,102	1,731	1,339	2,043	1,589	1,283	2,150	1,923	1,373
HRSG Fuel (HHV)	MMBtu/hr	0	0	0	0	0	0	0	0	0
Total Fuel (HHV)	MMBtu/hr	2,102	1,731	1,339	2,043	1,589	1,283	2,150	1,923	1,373
CT Fuel	lb/hr	90,871	74,840	57,896	88,330	68,681	55,452	92,955	83,126	59,382
HRSG Fuel	lb/hr	0	0	0	0	0	0	0	0	0
Total Fuel	lb/hr	90,871	74,840	57,896	88,330	68,681	55,452	92,955	83,126	59,382
Inlet Air (each CT)										
N_2	mole % dry	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%	78.04%
O_2	mole % dry	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%	20.99%
CO_2	mole % dry	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
Ar	mole % dry	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight, dry air		28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97	28.97
Dry Bulb Temperature	deg. F	53.5	59.0	59.0	75.5	104.4	104.4	34.0	34.0	34.0
Moisture Content of Ambient Air	lb H_20/lb air	0.0064	0.0064	0.0064	0.0082	0.0082	0.0082	0.0034	0.0034	0.0034
Moisture Content of Inlet Air	lb H_20/lb air	0.0076	0.0064	0.0064	0.0149	0.0082	0.0082	0.0034	0.0034	0.0034

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	**Case D**	**Case R**	**Case H**	**Case J**	**Case X**	**Case 01C**	**Case 01F**	**Case 01E**
		Max All Units	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**
Relative Humidity of Inlet Air	%	88%	60%	60%	78%	18%	18%	83%	83%	83%
Moisture Content	moles $H_2$0/mole air	0.012	0.010	0.010	0.024	0.013	0.013	0.005	0.005	0.005
N_2	mole %	77.09%	77.25%	77.25%	76.22%	77.02%	77.02%	77.61%	77.61%	77.61%
O_2	mole %	20.74%	20.78%	20.78%	20.50%	20.72%	20.72%	20.88%	20.88%	20.88%
CO_2	mole %	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
H_2O	mole %	1.21%	1.01%	1.01%	2.34%	1.30%	1.30%	0.55%	0.55%	0.55%
Ar	mole %	0.93%	0.93%	0.93%	0.92%	0.93%	0.93%	0.93%	0.93%	0.93%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight		28.83	28.86	28.86	28.71	28.82	28.82	28.91	28.91	28.91
Inlet Air Flow	lb/hr	4,025,259	3,241,369	2,687,064	3,984,360	3,087,806	2,713,728	4,069,355	3,554,946	2,675,348
Combustion Turbine Exhaust (each CT)										
Excess Combustion Air	%	**163.8%**	**158.3%**	**176.7%**	**166.7%**	**167.6%**	**191.3%**	**161.8%**	**155.8%**	**169.4%**
N_2	lb/hr	3,016,114	2,431,819	2,015,898	2,964,181	2,312,374	2,032,170	3,061,989	2,674,949	2,013,044
O_2	lb/hr	575,145	457,642	395,396	569,015	444,768	409,850	581,175	500,285	388,772
CO_2	lb/hr	246,642	203,099	157,200	239,767	186,434	150,625	252,287	225,572	161,202
H_2O	lb/hr	226,443	181,896	141,853	248,832	173,208	141,642	214,285	191,339	137,148
Ar	lb/hr	51,786	41,753	34,613	50,894	39,703	34,893	52,573	45,927	34,564
Total Exhaust Flow	lb/hr	4,116,130	3,316,209	2,744,960	4,072,690	3,156,487	2,769,180	4,162,310	3,638,072	2,734,730
Manufacturer's Exhaust Flow	lb/hr	**4,116,130**	**3,316,209**	**2,744,960**	**4,072,690**	**3,156,487**	**2,769,180**	**4,162,310**	**3,638,072**	**2,734,730**
N_2	mass %	73.28%	73.33%	73.44%	72.78%	73.26%	73.39%	73.56%	73.53%	73.61%
O_2	mass %	13.97%	13.80%	14.40%	13.97%	14.09%	14.80%	13.96%	13.75%	14.22%
CO_2	mass %	5.99%	6.12%	5.73%	5.89%	5.91%	5.44%	6.06%	6.20%	5.89%
H_2O	mass %	5.50%	5.49%	5.17%	6.11%	5.49%	5.11%	5.15%	5.26%	5.02%
Ar	mass %	1.26%	1.26%	1.26%	1.25%	1.26%	1.26%	1.26%	1.26%	1.26%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
N_2	moles/hr	107,667	86,809	71,962	105,813	82,545	72,543	109,304	95,488	71,860
O_2	moles/hr	17,974	14,302	12,357	17,782	13,899	12,808	18,162	15,634	12,150
CO_2	moles/hr	5,620	4,628	3,582	5,463	4,248	3,432	5,749	5,140	3,673
H_2O	moles/hr	12,569	10,097	7,874	13,812	9,614	7,862	11,895	10,621	7,613
Ar	moles/hr	1,296	1,045	866	1,274	994	873	1,316	1,150	865
Total	moles/hr	145,126	116,881	96,641	144,145	111,301	97,519	146,426	128,033	96,161

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit
N_2	mole %	74.19%	74.27%	74.46%	73.41%	74.16%	74.39%	74.65%	74.58%	74.73%
O_2	mole %	12.38%	12.24%	12.79%	12.34%	12.49%	13.13%	12.40%	12.21%	12.63%
CO_2	mole %	3.87%	3.96%	3.71%	3.79%	3.82%	3.52%	3.93%	4.01%	3.82%
H_2O	mole %	8.66%	8.64%	8.15%	9.58%	8.64%	8.06%	8.12%	8.30%	7.92%
Ar	mole %	0.89%	0.89%	0.90%	0.88%	0.89%	0.90%	0.90%	0.90%	0.90%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Molecular Weight		28.37	28.38	28.41	28.26	28.36	28.40	28.43	28.42	28.44
CT Emissions (each CT) - Expected										
NO_X, @ 15% O_2	ppmvd	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**
CO	ppmvd	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**
POC	ppmvw	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
NO_X, as NO_2	lb/hr	68.3	56.2	43.5	66.4	51.6	41.6	69.8	62.5	44.6
CO	lb/hr	33.4	26.9	22.4	32.9	25.6	22.6	33.9	29.6	22.3
POC, as CH_4	lb/hr	3.3	2.6	2.2	3.2	2.5	2.2	3.3	2.9	2.2
PM_{10}	lb/hr	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**
Portion of PM_{10} from Sulfur Particulates	lb/hr	0.61	0.51	0.39	0.60	0.46	0.37	0.63	0.56	0.40
Portion of PM_{10} from Soot/Ash	lb/hr	8.4	8.5	8.6	8.4	8.5	8.6	8.4	8.4	8.6
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0
Total Emissions Upstream of Catalyst (each CT)										
NO_X, as NO_2	lb/hr	68.3	56.2	43.5	66.4	51.6	41.6	69.8	62.5	44.6
CO	lb/hr	33.4	26.9	22.4	32.9	25.6	22.6	33.9	29.6	22.3
POC, as CH_4	lb/hr	3.3	2.6	2.2	3.2	2.5	2.2	3.3	2.9	2.2
PM_{10}	lb/hr	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Portion of PM_{10} from Sulfur Particulates	lb/hr	0.6	0.5	0.4	0.6	0.5	0.4	0.6	0.6	0.4
Portion of PM_{10} from Soot/Ash	lb/hr	8.4	8.5	8.6	8.4	8.5	8.6	8.4	8.4	8.6
SO_2 Converted to PM_{10} w/in CT & HRSG	lb/hr	0.29	0.24	0.19	0.28	0.22	0.18	0.30	0.27	0.19
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit
CO Catalyst Performance (each CT)										
Required CO Reduction	lb/hr	28.8	23.1	19.4	28.4	22.1	19.8	29.2	25.4	19.3
Required CO Reduction (mass basis)	%	86%	86%	87%	86%	86%	88%	86%	86%	86%
Required POC Reduction	lb/hr	0.6	0.4	0.5	0.7	0.5	0.6	0.6	0.5	0.4
Required POC Reduction (mass basis)	%	19%	17%	22%	21%	20%	26%	18%	16%	20%
PM_{10} Increase from Sulfur Particulates	lb/hr	9.3	7.7	5.9	9.1	7.0	5.7	9.5	8.5	6.1
SO_2 Converted to PM_{10} w/in CO Catalyst	lb/hr	4.46	3.67	2.84	4.33	3.37	2.72	4.56	4.08	2.91
NOx Catalyst Performance (each CT)										
Required NO_X Reduction, as NO_2	lb/hr	56.9	46.9	36.2	55.3	43.0	34.7	58.2	52.1	37.2
Required NO_X Reduction (mass basis)	%	83%	83%	83%	83%	83%	83%	83%	83%	83%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.23	0.19	0.15	0.23	0.18	0.14	0.24	0.21	0.15
NH_3 Slip	lb/hr	14.0	11.6	8.9	13.6	10.6	8.6	14.4	12.8	9.2
NH_3 Reacted	lb/hr	22.1	18.2	14.1	21.5	16.7	13.5	22.6	20.2	14.4
Total NH_3 Added	lb/hr	36.2	29.8	23.0	35.1	27.3	22.0	37.0	33.1	23.6
Stack Exhaust Analysis (each CT)										
N_2	lb/hr	3,016,114	2,431,819	2,015,898	2,964,181	2,312,374	2,032,170	3,061,989	2,674,949	2,013,044
O_2	lb/hr	575,145	457,642	395,396	569,015	444,768	409,850	581,175	500,285	388,772
CO_2	lb/hr	246,642	203,099	157,200	239,767	186,434	150,625	252,287	225,572	161,202
H_2O	lb/hr	226,443	181,896	141,853	248,832	173,208	141,642	214,285	191,339	137,148
Ar	lb/hr	51,786	41,753	34,613	50,894	39,703	34,893	52,573	45,927	34,564
Total	lb/hr	4,116,130	3,316,209	2,744,960	4,072,690	3,156,487	2,769,180	4,162,310	3,638,072	2,734,730
N_2	mass %	73.3%	73.3%	73.4%	72.8%	73.3%	73.4%	73.6%	73.5%	73.6%
O_2	mass %	14.0%	13.8%	14.4%	14.0%	14.1%	14.8%	14.0%	13.8%	14.2%
CO_2	mass %	6.0%	6.1%	5.7%	5.9%	5.9%	5.4%	6.1%	6.2%	5.9%
H_2O	mass %	5.5%	5.5%	5.2%	6.1%	5.5%	5.1%	5.1%	5.3%	5.0%
Ar	mass %	1.3%	1.3%	1.3%	1.2%	1.3%	1.3%	1.3%	1.3%	1.3%
Total	mass %	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	Case D	Case R	Case H	Case J	Case X	Case 01C	Case 01F	Case 01E
		Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit	Max All Units	Med Output All Units	Min Output One Unit
N_2	moles/hr	107,649	86,794	71,950	105,796	82,532	72,532	109,286	95,472	71,848
O_2	moles/hr	17,971	14,299	12,355	17,779	13,897	12,806	18,159	15,632	12,148
CO_2	moles/hr	5,619	4,627	3,581	5,462	4,247	3,432	5,748	5,139	3,672
H_2O	moles/hr	12,567	10,095	7,873	13,810	9,613	7,861	11,893	10,619	7,612
Ar	moles/hr	1,296	1,045	866	1,274	994	873	1,316	1,149	865
Total	moles/hr	145,102	116,861	96,625	144,121	111,283	97,504	146,401	128,011	96,145
N_2	mole%	74.2%	74.3%	74.5%	73.4%	74.2%	74.4%	74.6%	74.6%	74.7%
O_2	mole%	12.4%	12.2%	12.8%	12.3%	12.5%	13.1%	12.4%	12.2%	12.6%
CO_2	mole%	3.9%	4.0%	3.7%	3.8%	3.8%	3.5%	3.9%	4.0%	3.8%
H_2O	mole%	8.7%	8.6%	8.1%	9.6%	8.6%	8.1%	8.1%	8.3%	7.9%
Ar	mole%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%
Total	mole%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Molecular Weight		28.37	28.38	28.41	28.26	28.36	28.40	28.43	28.42	28.44
Stack Temperature	deg. F	191	180	171	213	196	180	192	185	171
Stack Temperature	deg. K	361.43	355.22	350.59	373.59	364.46	355.21	361.82	358.03	350.54
Stack Flow	cf/hr	69,006,000	54,620,000	44,575,000	70,845,000	53,366,000	45,572,000	69,698,000	60,306,000	44,346,000
Stack Velocity	ft/sec	72.3	57.2	46.7	74.3	55.9	47.8	73.0	63.2	46.5
Stack Velocity	m/sec	22.0	17.4	14.2	22.6	17.0	14.6	22.3	19.3	14.2
Calculated Stack Emissions (each CT)										
NO_X, @ 15% O_2	ppmvd	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CO, @ 15% O_2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
POC, as CH_4 @ 15% O2	ppmvd	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NH_3 slip, @ 15% O_2	ppmvd	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NO_X, as NO_2	lb/hr	11.4	9.4	7.2	11.1	8.6	6.9	11.6	10.4	7.4
CO	lb/hr	4.6	3.8	2.9	4.5	3.5	2.8	4.7	4.2	3.0
POC, as CH_4	lb/hr	2.6	2.2	1.7	2.6	2.0	1.6	2.7	2.4	1.7
Total PM_{10} from Sulfur Particulates	lb/hr	9.8	8.1	6.3	9.6	7.4	6.0	10.1	9.0	6.4
Total PM_{10}	lb/hr	**18.6**	**16.9**	**15.1**	**18.3**	**16.2**	**14.8**	**18.8**	**17.7**	**15.2**
NH_3	lb/hr	14.0	11.6	8.9	13.6	10.6	8.6	14.4	12.8	9.2
Maximum SO_2	lb/hr	5.9	4.8	3.7	5.7	4.4	3.6	6.0	5.4	3.8
Annual Average SO_2	lb/hr	1.5	1.2	0.9	1.4	1.1	0.9	1.5	1.3	1.0

Table 5.1A-3a

Oakley Generating Station 2x1

Combustion Turbine/HRSG Operating Emissions and Support Data

		ISO Conditions			Peak July Conditions			Minimum Ambient		
		Case B	**Case D**	**Case R**	**Case H**	**Case J**	**Case X**	**Case 01C**	**Case 01F**	**Case 01E**
		Max All Units	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**	**Max All Units**	**Med Output All Units**	**Min Output One Unit**
Permitted Stack Emissions (each CT)										
NO$_X$, @ 15% O$_2$	ppmvd	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
CO, @ 15% O$_2$	ppmvd	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
POC, as CH$_4$ @ 15% O2	ppmvd	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**
NH$_3$ Slip, @ 15% O$_2$	ppmvd	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**	**5.0**
NO$_X$, as NO$_2$	lb/hr	15.17	12.50	9.66	14.75	11.47	9.25	15.52	13.88	9.91
CO	lb/hr	9.24	7.61	5.88	8.98	6.98	5.63	9.45	8.45	6.04
POC, as CH$_4$	lb/hr	2.65	2.18	1.68	2.57	2.00	1.61	2.71	2.42	1.73
Total PM$_{10}$	lb/hr	**9.00**	**9.00**	**9.00**	**9.00**	**9.00**	**9.00**	**9.00**	**9.00**	**9.00**
NH$_3$	lb/hr	14.04	11.57	8.94	13.65	10.61	8.56	14.36	12.85	9.17
Maximum SO$_2$	lb/hr	5.90	4.80	3.70	5.70	4.40	3.60	6.00	5.40	3.80
Annual Average SO$_2$	lb/hr	1.50	1.20	0.90	1.40	1.10	0.90	1.50	1.30	1.00
NO$_X$, as NO$_2$	lb/MMBtu(HHV)	0.00722	0.00722	0.00721	0.00722	0.00722	0.00721	0.00722	0.00722	0.00722
CO	lb/MMBtu(HHV)	0.00440	0.00440	0.00439	0.00439	0.00439	0.00439	0.00440	0.00440	0.00439
POC, as CH$_4$	lb/MMBtu(HHV)	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126	0.00126
Total PM$_{10}$	lb/MMBtu(HHV)	0.00428	0.00520	0.00672	0.00441	0.00567	0.00702	0.00419	0.00468	0.00655
Maximum SO$_2$	lb/MMBtu(HHV)	0.00281	0.00277	0.00276	0.00279	0.00277	0.00281	0.00279	0.00281	0.00277
Annual Maximum SO$_2$	lb/MMBtu(HHV)	0.00071	0.00069	0.00067	0.00069	0.00069	0.00070	0.00070	0.00068	0.00073
CO$_2$	lb/MMBtu(HHV)	117.35	117.33	117.39	117.36	117.36	117.44	117.34	117.32	117.37

Table 5.1A-3b

Oakley Generating Station 2x1

Evaporative Fluid Cooler Operating Emissions

Operating Conditions		**Peak July Conditions**
		Case H
Ambient Dry Bulb Temp.	deg. F	104.4
Ambient Wet Bulb Temp.	deg. F	70.4
Relative Humidity	%	18%
Elevation	ft	21.0
Ambient Pressure	psia	14.68
Combustion Turbine Load	%	100%
Combustion Turbines Operating		2
Evaporative Cooling or Fogging? (Yes/No)		Yes
Duct Firing? (Yes/No)		No
Steam or Water Injection? (Yes/No)		No
Evaporative Fluid Cooler Performance		
Allowance to WB Temp to Account for Recirculation	deg. F	-
EFC Design Wet Bulb Temperature	deg. F	70.4
Closed Loop Cooling Water Flow	gpm	**5,610**
EFC Circulating Flow	gpm	**5,880**
Heat Rejected from Closed Loop Cooling Water	MMBtu/hr	43.2
Closed Loop Cooling Water Outlet Temperature	deg. F	105.0
Closed Loop Cooling Water Inlet Temperature	deg. F	120.4
Require Approach Temperature	deg. F	34.6
Makeup Water Temperature	deg. F	**70.0**
Number of Cells		**3**
Number of Fans Operating		**3**
Fan Stack Diameter	ft	**11.00**
Leaving Air Flow/Fan	acfm	**190,600**
Total Leaving Air Flow	acfm	571,800
Stack Velocity	ft/sec	33.4
Wet Bulb Temperature of Leaving Air	deg. F	**87.91**
Enthalpy of Leaving Air	Btu/lb	53.1
Moisture Content of Leaving Air	grains/lb dry air	204
Humidity Ratio of Leaving Air	lb water/lb dry air	0.0291
Density of Leaving Air	lbs/cf	0.0712
Total Dry Air Flow	lb/min	39,537
L/G Ratio		1.239
Enthalpy of Entering Air	Btu/lb	34.1
Moisture Content of Entering Air	grains/lb dry air	57
Humidity Ratio of Entering Air	lb water/lb dry air	0.0082
Heat Removed by Air	MMBtu/hr	43
Qair/Qcw		100%
Evaporation	gpm	99
Drift, percent of circulating water flow	%	**0.0030%**
Drift	gpm	0.18
Drift	lb/hr	0.17
EFC Circulating Water TDS	mg/l	**1,500**
% PM_{10} Emissions	% of total	**100%**
PM_{10} Emissions	lbs/hr	0.132

Table 5.1A-3c

RADBACK ENERGY

Oakley Generating Station 2x1

Auxiliary Boiler Operating Emissions

Auxiliary Boiler		
Operating Conditions		
Ambient Dry Bulb Temp.	deg. F	59.0
Ambient Wet Bulb Temp.	deg. F	51.5
Relative Humidity	%	60%
Elevation	ft	21.0
Ambient Pressure	psia	14.68
Auxiliary Boiler Firing Rate	%	100%
Fuel Input		
Fuel (LHV)	MMBtu/hr	45.7
HHV/LHV =	1.1085	
Fuel (HHV)	MMBtu/hr	50.6
Fuel	lb/hr	2,188
Combustion Air		
N_2	mole % dry	78.04%
O_2	mole % dry	20.99%
CO_2	mole % dry	0.03%
Ar	mole % dry	0.94%
Total		100.00%
Molecular Weight, dry air		28.97
Inlet Air Dry Bulb Temperature	deg. F	59.0
Moisture Content of Inlet Air	lb H_20/lb air	0.0064
Moisture Content	moles H_20/mole air	0.010
N_2	mole %	77.25%
O_2	mole %	20.78%
CO_2	mole %	0.03%
H_2O	mole %	1.01%
Ar	mole %	0.93%
Total		100.00%
Molecular Weight		28.86
Inlet Air Flow	lb/hr	42,208
Boiler Exhaust		
Excess Combustion Air	%	15.0%
N_2	lb/hr	31,683
O_2	lb/hr	1,270
CO_2	lb/hr	5,915
H_2O	lb/hr	4,985
Ar	lb/hr	544
Total Exhaust Flow	lb/hr	44,396
Manufacturer's Exhaust Flow	lb/hr	44,396
N_2	mass %	71.36%
O_2	mass %	2.86%
CO_2	mass %	13.32%
H_2O	mass %	11.23%
Ar	mass %	1.22%
Total		100.00%

Table 5.1A-3c

Oakley Generating Station 2x1

Auxiliary Boiler Operating Emissions

Auxiliary Boiler		
N_2	moles/hr	1,131
O_2	moles/hr	40
CO_2	moles/hr	135
H_2O	moles/hr	277
Ar	moles/hr	14
Total	moles/hr	1,596
N_2	mole %	70.87%
O_2	mole %	2.49%
CO_2	mole %	8.45%
H_2O	mole %	17.34%
Ar	mole %	0.85%
Total		100.00%
Molecular Weight		27.83
Boiler Emissions Upstream of Catalyst		
NO_x, @ 3% O_2	ppmvd	**7.0**
CO, @ 3% O_2	ppmvd	**10.0**
POC, @ 3% O_2	ppmvd	**5.00**
NO_x, as NO_2	lb/hr	0.4
CO	lb/hr	0.4
POC, as CH_4	lb/hr	0.1057
PM_{10}	lb/hr	**0.52**
PM_{10} Increase from Sulfur Particulates	lb/hr	0.01
SO_2 Converted to PM_{10} within Boiler	lb/hr	0.01
SO_2	lb/hr	0.14
CO Catalyst Performance		
Required CO Reduction	lb/hr	0.0
Required CO Reduction (mass basis)	%	0%
Required POC Reduction	lb/hr	0.0
Required POC Reduction (mass basis)	%	0%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.0
SO_2 Converted to PM_{10} within CO Catalyst	lb/hr	0.0
NO_x Catalyst Performance		
Required NO_x Reduction, as NO_2	lb/hr	0.0
Required NO_x Reduction (mass basis)	%	0%
PM_{10} Increase from Sulfur Particulates	lb/hr	0.00
NH_3 Slip	lb/hr	0.0
NH_3 Reacted	lb/hr	0.0
Total NH_3 Added	lb/hr	0.0

Table 5.1A-3c

Oakley Generating Station 2x1

Auxiliary Boiler Operating Emissions

Auxiliary Boiler		
Boiler Stack Exhaust Analysis		
N_2	lb/hr	31,683
O_2	lb/hr	1,270
CO_2	lb/hr	5,915
H_2O	lb/hr	4,985
Ar	lb/hr	544
Total	lb/hr	44,396
N_2	mass %	71.4%
O_2	mass %	2.9%
CO_2	mass %	13.3%
H_2O	mass %	11.2%
Ar	mass %	1.2%
Total	mass %	100.0%
N_2	moles/hr	1,131
O_2	moles/hr	40
CO_2	moles/hr	135
H_2O	moles/hr	277
Ar	moles/hr	14
Total	moles/hr	1,595
N_2	mole%	70.9%
O_2	mole%	2.5%
CO_2	mole%	8.4%
H_2O	mole%	17.3%
Ar	mole%	0.9%
Total	mole%	100.0%
Molecular Weight		27.83
Stack Temperature	deg. F	**290**
Stack Temperature	deg. K	416
Stack Flow	acfh	874,000
Stack Flow	acfm	14,566.67
Stack Velocity	ft/sec	49.46
Stack Velocity	m/sec	15.08
Calculated Boiler Stack Emissions		
NO_x, @ 3% O_2	ppmvd	7.0
CO, @ 3% O_2	ppmvd	10.0
POC, as CH_4 @ 3% O2	ppmvd	5.00
NH_3 slip, @ 3% O_2	ppmvd	0.0
NOx, as NO_2	lb/hr	0.4
CO	lb/hr	0.4
POC, as CH_4	lb/hr	0.1057
Total PM_{10} from Sulfur Particulates	lb/hr	0.01
Total PM_{10}	lb/hr	0.53
NH_3	lb/hr	0.00
SO_2	lb/hr	0.14

Table 5.1A-3c

Oakley Generating Station 2x1

Auxiliary Boiler Operating Emissions

Auxiliary Boiler		
Permitted Boiler Stack Emissions		
NO_x, @ 3% O_2	ppmvd	**7.0**
CO, @ 3% O_2	ppmvd	**10.0**
POC, as CH_4 @ 3% O2	ppmvd	**5.0**
Total PM_{10}	lbs/MMBtu HHV	**0.0070**
NH_3 Slip, @ 3% O_2	ppmvd	**0.0**
NO_x, as NO_2	lb/hr	0.42
CO	lb/hr	0.37
POC, as CH_4	lb/hr	0.11
Total PM_{10}	lb/hr	0.35
Total PM_{10}	lbs/MMscf	7.2
NH_3	lb/hr	0.00
SO_2	lb/hr	0.14
SO_2	lbs/MMscf	2.85
NO_x, as NO_2	g/s	0.053
CO	g/s	0.047
POC, as CH4	g/s	0.013
Total PM_{10}	g/s	0.045
NH_3	g/s	0.000
SO_2	g/s	0.018

Table 5.1A-4

Calculation of Hazardous and Toxic Pollutant Emissions

# of Units: 2

Fuel HHV: 1022 btu/scf

Calculation of Noncriteria Pollutant Emissions from Gas Turbines

		(each turbine)			All Turbines			
Compound	Emission Factor, lb/MMscf	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Annual Emissions, lb/yr	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Annual Emissions, lb/yr	Annual Emissions, tons/yr
Acetaldehyde	1.37E-01	2.88E-01	6.91E+00	2.37E+03	5.76E-01	1.38E+01	4.75E+03	2.37E+00
Acrolein	1.89E-02	3.98E-02	9.53E-01	3.27E+02	7.95E-02	1.91E+00	6.55E+02	3.27E-01
Ammonia	(3)	1.40E+01	3.36E+02	1.18E+05	2.80E+01	6.72E+02	2.37E+05	1.18E+02
Benzene	1.33E-02	2.80E-02	6.71E-01	2.30E+02	5.60E-02	1.34E+00	4.61E+02	2.30E-01
1,3-Butadiene	1.27E-04	2.67E-04	6.41E-03	2.20E+00	5.34E-04	1.28E-02	4.40E+00	2.20E-03
Ethylbenzene	1.79E-02	3.77E-02	9.03E-01	3.10E+02	7.53E-02	1.81E+00	6.20E+02	3.10E-01
Formaldehyde	9.17E-01	1.93E+00	4.63E+01	1.59E+04	3.86E+00	9.25E+01	3.18E+04	1.59E+01
Hexane	2.59E-01	5.45E-01	1.31E+01	4.49E+03	1.09E+00	2.61E+01	8.97E+03	4.49E+00
Naphthalene	1.66E-03	3.49E-03	8.37E-02	2.87E+01	6.99E-03	1.67E-01	5.75E+01	2.87E-02
Total PAHs	2.41E-04	5.07E-04	1.22E-02	4.17E+00	1.01E-03	2.43E-02	8.35E+00	4.17E-03
Propylene	7.71E-01	1.62E+00	3.89E+01	1.34E+04	3.24E+00	7.78E+01	2.67E+04	1.34E+01
Propylene oxide	4.78E-02	1.01E-01	2.41E+00	8.28E+02	2.01E-01	4.82E+00	1.66E+03	8.28E-01
Toluene	7.10E-02	1.49E-01	3.58E+00	1.23E+03	2.99E-01	7.16E+00	2.46E+03	1.23E+00
Xylene	2.61E-02	5.49E-02	1.32E+00	4.52E+02	1.10E-01	2.63E+00	9.04E+02	4.52E-01
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Notes:

(1) Provided by CATEF database.

(2) Based on maximum hourly turbine fuel use of: 2.1040E+00 mmscf/hr

Based on a maximum daily turbine fuel use of: 5.0449E+01 mmscf/day

Based on maximum annual turbine fuel use of: 1.7318E+04 mmscf/yr
Fuel use values from Fuel Calculation Sheet

(3) Values from ammonia slip calculations.

(4) Fuel use values include HRSG duct burner(s) Yes or No: No

Each Turbine	24	Max hrs/day
Each Turbine	8463	Max Hrs/yr

Table 5.1A-5a

RADBACK ENERGY

Oakley Generating Station 2x1

Combustion Turbine Startup Emissions

Calculated Values		Proposed Limits
Hot Start		
Start Duration, minutes	14.0	**30.0**
Total per Start (per turbine)		
NO$_x$, lbs	22.0	**22.0**
CO, lbs	85.0	**85.0**
POC, lbs	31.0	**31.0**
PM$_{10}$, lbs	2.1	
SO$_2$, lbs (maximum)	0.9	
SO$_2$, lbs (annual average)	0.2	
Warm Start		
Start Duration, minutes	14.0	**30.0**
Total per Start (per turbine)		
NO$_x$, lbs	22.0	**22.0**
CO, lbs	85.0	**85.0**
POC, lbs	31.0	**31.0**
PM$_{10}$, lbs	2.1	
SO$_2$, lbs (maximum)	0.9	
SO$_2$, lbs (annual average)	0.2	
Cold Start		
Start Duration, minutes	45.0	**90.0**
Total per Start (per turbine)	5.0	
NO$_x$, lbs	96.0	**96.0**
CO, lbs	360.0	**360.0**
POC, lbs	67.0	**67.0**
PM$_{10}$, lbs	6.8	
SO$_2$, lbs (maximum)	2.9	
SO$_2$, lbs (annual average)	0.8	
Shutdown		
Shutdown Duration, minutes	30.0	**60.0**
Total per Shutdown (per turbine)		
NO$_x$, lbs	39.0	**39.0**
CO, lbs	140.0	**140.0**
POC, lbs	17.0	**17.0**
PM$_{10}$, lbs	4.5	
SO$_2$, lbs (maximum)	1.9	
SO$_2$, lbs (annual average)	0.5	

Table 5.1A-5b

Oakley Generating Station 2x1

Combustion Turbine Commissioning Emissions Summary

Description	NO_x	CO	POC	PM_{10}	SO_2
Commissioning Emissions Above Normal Operating Levels (for Two Units), tons [1]	28.6	40.8	6.4	3.7	1.7
Commissioning Emissions Within Normal Operating Levels (for Two Units), tons [2]	13.4	8.2	2.3	7.8	1.3
Total Commissioning Emissions (for Two Units), tons	42.0	49.0	8.7	11.5	3.0
Maximum Hour (each CTG/HRSG), lb/hr [3]	148.7	700.0	37.9	9.0	6.0
Commissioning Hours Above Normal Operating Levels (for Two Units), hrs [4]	831				
Commissioning Hours Within Normal Operating Levels (for Two Units), hrs [5]	1,725				
Total Commissioning Hours (for Two Units), hrs	2,556				

Notes:

1. SO_2 emissions are calculated based on total fuel consumed assuming 0.25 gr S/100 scf.
2. Emissions are based on the maximum normal operations emissions rates assuming 2 ppm NO_X, 2 ppm CO, and 0.25 gr S/100 scf.
3. SO_2 emissions are calculated based on total fuel consumed assuming 1 gr S/100 scf.
4. Commissioning time with uncontrolled or partially controlled emissions.
5. Commissioning time with units operating within normal operating permit limits.

Table 5.1A-5b

Test Description	GT Load Range	Averge GT Load	Total Firing	Total Fuel	Uncontrolled or Partially Controlled Emissions (Exceeding Normal Operating Limits)									Hours Within Normal Operating Limits
						Emissions Rate				Total Emissions				
						NOx	CO	VOC	PM10	NOx	CO	VOC	PM10	
					Hours	lbs/hr	lbs/hr	lbs/hr	lbs/hr	tons	tons	tons	tons	
GT Initial Start-up	0	0	50	29898	50	61.1	450.2	37.9	9.0	1.5	11.4	1.0	0.2	0
GT first firing														
GT FSNL on primary fuel & generator filtration														
GT intertriping matrix checks														
GT generator short circuit, overspeed and open circuit tests														
GT Sync & Load	7.5	7.5	10	7459	10	148.7	700.0	36.3	9.0	0.7	3.5	0.2	0.0	0
GT first synchro														
HRSG Steam blows	7.5	7.5	240	177147	240	47.3	115.6	36.3	9.0	5.7	13.8	4.3	1.1	0
HRSG MS steam blows														
HRSG CRH & HRH steam blows														
HRSG LP steam blows														
Air cooled condenser flushing														
Steam to gland seal, condenser vacuum tests														
HRSG Operation on Steam Bypass	25	25	323	355692	323	99.2	60.1	3.6	9.0	16.0	9.7	0.6	1.5	0
HRSG startup, steam bypasses checks														
HRSG steam safety valves tests														
HRSG & BOP control loop tuning														
GT Loading up to Base on PPM	25 to 100	46	101	149522	50	99.2	60.1	3.6	9.0	2.5	1.5	0.1	0.2	50
Part load tests														
Full load tests														
HRSG operation on bypass for steam purity														
ST Initial Start-up	7.5 to 25	19	23	22267	23	99.2	60.1	3.6	9.0	1.1	0.7	0.0	0.1	0
ST generator filtration														
ST intertriping checks														
ST generator short circuit, overspeed and open circuit tests														
ST Sync & Load	25 to 75	68	58	108814	38	15.5	3.4	2.4	9.0	0.3	0.1	0.0	0.2	20
ST first synchro														
ST tests on load with one GT														
GT Tuning up to Base on PSS Mode with Primary Fuel	50 to 100	64	146	262728	97	14.8	3.3	2.3	9.0	0.7	0.2	0.1	0.4	50
Part load tests														
Full load tests														
CC Operation Tuning	50 to 100	76	575	1156987	0					0.0	0.0	0.0	0.0	575
GT part load, full load rejection & house load tests														
GT, HRSG & ST trip tests and operation tuning														
HRSG's steam coupling & and CC operation tuning														
ST full load														
Hot, warm, cold start-ups														
Restart														
Full Load														
GT's & ST part load, full load rejection & house load tests														
CC Performance tests (gazeous, noise emissions, output & HR)	100	100	121	294680	0					0.0	0.0	0.0	0.0	121
Capacity performance tests														
Precision performance tests														
Special tests	75	75	45	90430	0					0.0	0.0	0.0	0.0	45
Noise guarantee additional tests at part load														
Grid code tests, NPI tests, etc														
Other														
Reliability Run test	100	100	864	1869696	0					0.0	0.0	0.0	0.0	864
9 days RR														
Totals			2556	4525319	831					28.6	40.8	6.4	3.7	1725

Table 5.1A-6 Cooling Tower

Cooling Tower Particulate Emissions

# of Identical Towers:	1			**Per Tower**	**Per Cell**	**All Towers**
Operational Schedule:	Hrs/day	Days/Yr	Hrs/Yr			
	24	0	1500			
Pumping rate of recirculation pumps (gal/min)				5,880.0		
Flow of cooling water (lbs/hr)				2,938,824.0		
Avg TDS of circ water (mg/l or ppmw)				1,500.0		
Flow of dissolved solids (lbs/hr)				4408.24		
Fraction of flow producing drift				1.00		
Control efficiency of drift eliminators (gal drift/gal flow)				0.000030		
Calculated drift rate (lbs water/hr)				88.2		
PM10 emissions from tower (lbs/hr)				**0.132**	**0.044**	**0.132**
PM10 emissions from tower (tpy)				**0.099**	**0.033**	**0.099**
PM2.5 fraction of PM10				1.00		
PM2.5 emissions from tower (lbs/hr)				**0.132**	**0.044**	**0.132**
PM2.5 emissions from tower (tpy)				**0.099**	**0.033**	**0.099**

Notes:
Based on Method AP 42, Section 13.4, Jan 1995
Technical Report EPA-600-7-79-251a, Page 63
Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume 1.

Cooling Tower Stack Parameters

Base Elevation	0	feet amsl
Number of Cells	3	
Length of Cooling Tower	0.00	feet
Width of Cooling Tower	0.00	feet
Height of Cooling Tower (to fan deck)	0.00	feet agl
Cell Release Height (fan shroud exit)	0.00	feet agl
Flow/Fan Discharge for each Cell	0	ACFM
Inlet air temperature (ambient):	variable	deg F
Discharge air temperature:	variable	deg F

Table 5.1A-7

Calculation of Hazardous and Toxic Pollutant Emissions from Cooling Tower

				Op Hrs/Day:	24		
Cells per Tower:	3	Max Tower Drift Rate:	88.2 lbs/hr	Op Hrs/Yr:	1500	Average Tower Cycles of Concentration:	3
# of Identical Towers:	1						

			Total Single Tower			**Single Cell**			**Total All Towers**		
Constituent	Concentration in Cooling Tower Water		Emissions, lb/hr	Emissions, lb/day	Emissions, ton/yr	Emissions, lb/hr	Emissions, lb/day	Emissions, ton/yr	Emissions, lb/hr	Emissions, lb/day	Emissions, ton/yr
Manganese	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Magnesium	91	ppm	2.41E-02	5.78E-01	1.81E-02	8.03E-03	1.93E-01	6.02E-03	2.41E-02	5.78E-01	1.81E-02
Lead	0.0497	ppm	1.32E-05	3.16E-04	9.86E-06	4.38E-06	1.05E-04	3.29E-06	1.32E-05	3.16E-04	9.86E-06
Arsenic	0.069	ppm	1.83E-05	4.38E-04	1.37E-05	6.09E-06	1.46E-04	4.56E-06	1.83E-05	4.38E-04	1.37E-05
Aluminum	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium 6	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc	0.491	ppm	1.30E-04	3.12E-03	9.74E-05	4.33E-05	1.04E-03	3.25E-05	1.30E-04	3.12E-03	9.74E-05
Mercury	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper	0.177	ppm	4.68E-05	1.12E-03	3.51E-05	1.56E-05	3.75E-04	1.17E-05	4.68E-05	1.12E-03	3.51E-05
Silver	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
*	0	ppm	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Notes: (1) Water analysis data supplied by project applicant.

Table 5.1A-8 Auxiliary Boiler Emissions Estimates

Calculation of Criteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:	Normal firing mode		# of Units:	1
Ops Hr/Day:	24	Worst Case	Fuel Type:	Nat Gas
Ops Hr/Yr:	4324			

Calculation of Criteria Pollutant Emissions from Each Identical Unit

						All Units			
Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr (3)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
NOx	8.68E+00	4.30E-01	1.03E+01	1.86E+03	9.29E-01	4.30E-01	1.03E+01	1.86E+03	9.29E-01
CO	7.48E+00	3.70E-01	8.89E+00	1.60E+03	8.01E-01	3.70E-01	8.89E+00	1.60E+03	8.01E-01
VOC	2.14E+00	1.06E-01	2.54E+00	4.58E+02	2.29E-01	1.06E-01	2.54E+00	4.58E+02	2.29E-01
SOx	2.83E+00	1.40E-01	3.36E+00	6.05E+02	3.03E-01	1.40E-01	3.36E+00	6.05E+02	3.03E-01
PM10	7.17E+00	3.55E-01	8.52E+00	1.53E+03	7.67E-01	3.55E-01	8.52E+00	1.53E+03	7.67E-01
PM2.5	7.17E+00	3.55E-01	8.52E+00	1.53E+03	7.67E-01	3.55E-01	8.52E+00	1.53E+03	7.67E-01
NH3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	lbs/mscf								
CO2	1.21E+02	5.97E+03	1.43E+05	2.58E+07	1.29E+04	5.97E+03	1.43E+05	2.58E+07	1.29E+04
Methane	1.98E-04	9.82E-03	2.36E-01	4.25E+01	2.12E-02	9.82E-03	2.36E-01	4.25E+01	2.12E-02
N2O	1.98E-04	9.82E-03	2.36E-01	4.25E+01	2.12E-02	9.82E-03	2.36E-01	4.25E+01	2.12E-02
CO2e									1.29E+04
								metric tons	11741.1

Notes:	(1) natural gas criteria pollutant EF factors				
	(2) Based on maximum hourly boiler fuel use of			50.6	MMBtu/hr/boiler
	and fuel HHV of	1022	Btu/scf gives	0.0495	MMscf/hr/boiler.
	(3) Based on maximum annual boiler fuel use of			218,794	MMBtu/yr/boiler
	and fuel HHV of	1022	Btu/scf gives	214.0845	MMscf/yr/boiler.
	(4) APCs per AFC Section 5.1				
	(5) PM2.5 = PM10				

Refs:
(1) EFs from Radback Energy
(2) GHG EFs and GWP factors, BAAQMD Fact Sheet, Tables 1 and 2, 2-5-08.

Table 5.1A-9a Aux Boiler

Calculation of Noncriteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode:	Normal firing mode		# of Units:	1
Ops Hr/Day:	24	Worst Case	Fuel Type:	Nat Gas
Ops Hr/Yr:	4324			

		Calculation of Noncriteria Pollutant Emissions from Each Identical Unit				All Units			
Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr (3)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
Acetaldehyde	4.61E-03	2.28E-04	5.48E-03	9.87E-01	4.93E-04	2.28E-04	5.48E-03	9.87E-01	4.93E-04
Acrolein	4.51E-03	2.23E-04	5.36E-03	9.66E-01	4.83E-04	2.23E-04	5.36E-03	9.66E-01	4.83E-04
Ammonia	(5)	1.10E-01	2.64E+00	4.76E+02	2.38E-01	1.10E-01	2.64E+00	4.76E+02	2.38E-01
Benzene	2.43E-03	1.20E-04	2.89E-03	5.20E-01	2.60E-04	1.20E-04	2.89E-03	5.20E-01	2.60E-04
1,3-Butadiene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	2.25E-03	1.11E-04	2.67E-03	4.82E-01	2.41E-04	1.11E-04	2.67E-03	4.82E-01	2.41E-04
Formaldehyde	4.75E-03	2.35E-04	5.64E-03	1.02E+00	5.08E-04	2.35E-04	5.64E-03	1.02E+00	5.08E-04
Hexane	6.30E-03	3.12E-04	7.49E-03	1.35E+00	6.74E-04	3.12E-04	7.49E-03	1.35E+00	6.74E-04
Naphthalene	2.37E-04	1.17E-05	2.82E-04	5.07E-02	2.54E-05	1.17E-05	2.82E-04	5.07E-02	2.54E-05
PAHs (4)	8.10E-05	4.01E-06	9.62E-05	1.73E-02	8.67E-06	4.01E-06	9.62E-05	1.73E-02	8.67E-06
Propylene	4.63E-01	2.29E-02	5.50E-01	9.91E+01	4.96E-02	2.29E-02	5.50E-01	9.91E+01	4.96E-02
Propylene oxide	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene	3.23E-02	1.60E-03	3.84E-02	6.91E+00	3.46E-03	1.60E-03	3.84E-02	6.91E+00	3.46E-03
Xylene	1.87E-02	9.26E-04	2.22E-02	4.00E+00	2.00E-03	9.26E-04	2.22E-02	4.00E+00	2.00E-03
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Notes:

(1) natural gas HAPs emission factors

(2) Based on maximum hourly boiler fuel use of			50.6	MMBtu/hr/boiler
and fuel HHV of	1022	Btu/scf gives	0.0495	MMscf/hr/boiler.
(3) Based on maximum annual boiler fuel use of			218,794	MMBtu/yr/boiler
and fuel HHV of	1022	Btu/scf gives	214.0845	MMscf/yr/boiler.

(4) Polycyclic aromatic hydrocarbons, excluding naphthalene (treated separately).

(5) LNBs with SCR and CO Cat

Refs:

CARB Catef Database, Heater, NG, SCC 31000404
SDAPCD, B17, Toxics Efs Database

Table 5.1A-9b Aux Boiler

Calculation of Noncriteria Pollutant Emissions for Boilers Firing Gaseous Fuels

Boiler Operation Mode: Normal firing mode

Ops Hr/Day: 8 Worst Case

Ops Hr/Yr: 403

# of Units: 1

Fuel Type: Nat Gas

Calculation of Noncriteria Pollutant Emissions from Each Identical Unit

						All Units			
Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr (3)	Maximum Hourly Emissions, lb/hr	Maximum Daily Emissions, lb/day	Maximum Annual Emissions, lbs/yr	Annual Emissions, ton/yr
Acetaldehyde	4.61E-03	2.28E-04	1.83E-03	9.20E-02	4.60E-05	2.28E-04	1.83E-03	9.20E-02	4.60E-05
Acrolein	4.51E-03	2.23E-04	1.79E-03	9.00E-02	4.50E-05	2.23E-04	1.79E-03	9.00E-02	4.50E-05
Ammonia	(5)	1.10E-01	8.80E-01	4.43E+01	2.22E-02	1.10E-01	8.80E-01	4.43E+01	2.22E-02
Benzene	2.43E-03	1.20E-04	9.62E-04	4.85E-02	2.42E-05	1.20E-04	9.62E-04	4.85E-02	2.42E-05
1,3-Butadiene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Ethylbenzene	2.25E-03	1.11E-04	8.91E-04	4.49E-02	2.24E-05	1.11E-04	8.91E-04	4.49E-02	2.24E-05
Formaldehyde	4.75E-03	2.35E-04	1.88E-03	9.48E-02	4.74E-05	2.35E-04	1.88E-03	9.48E-02	4.74E-05
Hexane	6.30E-03	3.12E-04	2.50E-03	1.26E-01	6.29E-05	3.12E-04	2.50E-03	1.26E-01	6.29E-05
Naphthalene	2.37E-04	1.17E-05	9.39E-05	4.73E-03	2.36E-06	1.17E-05	9.39E-05	4.73E-03	2.36E-06
PAHs (4)	8.10E-05	4.01E-06	3.21E-05	1.62E-03	8.08E-07	4.01E-06	3.21E-05	1.62E-03	8.08E-07
Propylene	4.63E-01	2.29E-02	1.83E-01	9.24E+00	4.62E-03	2.29E-02	1.83E-01	9.24E+00	4.62E-03
Propylene oxide	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene	3.23E-02	1.60E-03	1.28E-02	6.44E-01	3.22E-04	1.60E-03	1.28E-02	6.44E-01	3.22E-04
Xylene	1.87E-02	9.26E-04	7.41E-03	3.73E-01	1.87E-04	9.26E-04	7.41E-03	3.73E-01	1.87E-04
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Notes:

(1) natural gas HAPs emission factors

(2) Based on maximum hourly boiler fuel use of 50.6 MMBtu/hr/boiler
and fuel HHV of 1022 Btu/scf gives 0.0495 MMscf/hr/boiler.

(3) Based on maximum annual boiler fuel use of 20,392 MMBtu/yr/boiler
and fuel HHV of 1022 Btu/scf gives 19.9528 MMscf/yr/boiler.

(4) Polycyclic aromatic hydrocarbons, excluding naphthalene (treated separately).

(5) LNBs with SCR and CO Cat

Refs:

CARB Catef Database, Heater, NG, SCC 31000404
SDAPCD, B17, Toxics Efs Database

Table 5.1A-10

Typical Diesel Fuel Analysis

Parameter	**Average Data**
Carbon %	85.86
Hydrogen %	13.35
Oxygen %	0.65
Nitrogen %	0.097
Sulfur %	0.0015 – 0.05
Ash %	0.01
Btu/gal (HHV)	~139,000
Lbs/gal	~6.87
Btu/lb	~19857

Data derived from AB2588 fuel testing for sources in the South Coast AQMD.
Total number of samples used for averages = 10.

Table 5.1A-11 - Combustion Turbine GHG Emissions Estimate

Greenhouse Gas Emissions Calculator

Combustion Turbines-Gaseous Fuels

Emissions Analysis Period: Annual

Facility Name: Radback-Oakley Generating Station

Gas Type: Natural Gas

Turbine Device ID: GE 7 FA w/HRSG (2)

Op Hours: 8463

Turbine Heat Rating: 4204 mmbtu/hr

Gas Btu Content: 1022 btu/scf Ref 1, Table C.5

Carbon Content: 14.47 kg/mmbtu
Frac Oxidized: 0.995
CO2/C Ratio: 3.6667

Annual Gas Usage: 34813 mmscf
35578452 mmbtu/yr

Emissions Factors:

CO2	118.9	lb/mmbtu	Ref 1
CH4	0.002	lb/mmbtu	Ref 1
N2O	0.00022	lb/mmbtu	Ref 1

	lbs/yr	kg/yr	**Emissions** metric tons/yr	IPCC GWP/SAR		CO2e metric tons/yr
CO2	4.230E+09	1.919E+09	1918854.07	1	Ref 2	1918854
CH4	7.116E+04	3.228E+04	32.2767717	25	Ref 2	807
N2O	7.827E+03	3.550E+03	3.55044488	298	Ref 2	1058
					Total	**1920719** **CO2e metric tons**

Source Specific Emissions Factor References, Data Notes, or Calculation Notes:
1. Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.
2. Fact Sheet, BAAQMD Proposed GHG Fee Schedule, 2-5-08.
3. ***
4. ***

Table 5.1A-12a EXPECTED INTERNAL COMBUSTION ENGINE EMISSIONS

Liquid Fuel

Emergency Fire Pump

			# of Identical Engines:	1	
Mfg:	Clarke		Stack Data		
Engine #:	JW6H-UFAD80		Height:	16	Ft.
Kw	0	approx.	Diameter:	0.67	Ft.
BHP:	400		Temp:	826	deg F
RPM:	-		ACFM:	2214	
Fuel:	#2 Diesel		input the mfg ACFM or calculate per Exhaust sheet)		
Fuel Use:	20	Gph (1)	Area:	0.353	Sq.Ft.
FuelHHV:	139000	Btu/gal	Velocity:	105	Ft/Sec
mmbtu/hr:	2.78	HHV	Max Daily Op Hrs:	1	
EPA/CARB Tier #:	3		Max Annual Op Hrs:	49	

Fuel Wt:	7	Lbs/gal
Fuel S:	0.0015	% wt.
Fuel S:	0.105	Lbs/1000 gal
SO2:	0.21	Lbs/1000 gal

			Single Engine				***All Engines***			
EFs (g/bhp-hr)			**Lb/Hr**	**Lb/Day**	**Lbs/Yr**	**Tons/Yr**	***Lb/Hr***	***Lb/Day***	***Lbs/Yr***	***Tons/Yr***
NOx	2.61		2.30	2.30	112.68	0.056	*2.30*	*2.30*	*112.68*	*0.06*
CO	0.84		0.74	0.74	36.26	0.018	*0.74*	*0.74*	*36.26*	*0.02*
VOC	0.104		0.09	0.09	4.49	0.002	*0.09*	*0.09*	*4.49*	*0.002*
PM10	0.103		0.09	0.09	4.45	0.002	*0.09*	*0.09*	*4.45*	*0.002*
SOx	NA		0.0042	0.0042	0.21	0.0001	*0.0042*	*0.0042*	*0.21*	*0.0001*
	lbs/gal									
CO2	22.38		448	448	21932	10.97	*448*	*448*	*21932*	*10.97*
Methane	0.000529		0.01	0.01	0.52	0.000	*0.01*	*0.01*	*0.52*	*0.000*
N2O	0.000198		0.00	0.00	0.19	0.0001	*0.00*	*0.00*	*0.19*	*0.0001*
CO2e						11.0				*11.00*
CO2e	21.7	Ref 5	434	434	21266	10.63	*434*	*434*	*21266*	*10.63*
									metric tons	*9.67*

Notes:

1. fuel consumption based on 0.055 gal/hp-hr (avg EPA and SCAQMD values) if no value given by mfg for specific engine.
2. PM10 equals PM2.5.
3. PM10 used in HRA to represent DPM emissions.
4. GHG EFs and GWP values from BAAQMD, Fact Sheet, Tables 1 and 2, 2-5-08.
5. Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.

JW6H-UFAD80
INSTALLATION & OPERATION DATA

Basic Engine Description

Engine Manufacturer	John Deere Co.
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in.(mm)	4.66 (118) X 5.35 (136)
Displacement - $in.^3$ (L)	496 (8.1)
Compression Ratio	16.0:1
Valves per cylinder - Intake	2
Exhaust	2
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Aspiration	Turbocharged
Firing Order (CW Rotation)	1-5-3-6-2-4
Charge Air Cooling Type	Raw Water Cooled
Rotation (Viewed from Front) - Clockwise	Standard
Counter-Clockwise	Not Available
Engine Crankcase Vent System	Open
Installation Drawing	D-628
Weight - lb (kg)	2094 (948)

Cooling System	**1760**	**2100**
Engine H_2O Heat -Btu/sec.(kW)	97.2 (103)	97.6 (102)
Engine Radiated Heat - Btu/sec.(kW)	96 (101)	90.5 (95)
Heat Exchanger Minimium Flow		
60°F (15°C) Raw H_2O - gal/min. (L/min.)	38 (144)	40 (151)
95°F (35°C) Raw H_2O - gal/min. (L/min.)	47 (178)	50 (189)
Heat Exchanger Maximum Cooling H_2O		
Inlet Pressure - bar ($lb./in.^2$) (kPa)	4 (60) (400)	
Flow - gal./min (L/min.)	80 (302)	
Thermostat, Start to Open - °F (°C)	180 (82)	
Fully Opened - °F (°C)	201 (94)	
Engine Coolant Capacity - qt. (L)	22 (20.8)	
Coolant Pressure Cap - $lb./in.^2$ (kPa)	15 (103)	
Maximum Engine H_20 Temperature - °F (°C)	221 (105)	
Minimum Engine H_20 Temperature - °F (°C)	160 (71)	

Electric System - DC

System Voltage (Nominal)	12 (Standard)	24 (Optional)
Battery Capacity for Ambients Above 32°F (0°C)		
Voltage (Nominal)	12	12
Qty. per Battery Bank	1	2
SAE size per J537	8D-900	8D-900
CCA @ 0°F (-18°C)	900	900
Reserve Capacity - Minutes	430	430
Battery Cable Circuit*, Max Resistance - ohm	0.0017	0.0017
Battery Cable Minimum Size		
0 -120 in. Circuit* Length	00	00
121 - 160 in. Circuit* Length	000	000
161 - 200 in. Circuit* Length	0000	0000
Charging Alternator Output - Amp	40	40
Starter Cranking Amps - @ 60°F (15°C)	495	326

**Positive and Negative Cables Combined Length*

NOTE: This engine is Intendend For Indoor Installation Or In A Weatherproof Enclosure.

(Continued)

JW6H-UFAD80
INSTALLATION & OPERATION DATA (Continued)

Exhaust System	**1760**	**2100**
Exhaust Flow - ft.^{3}/min. (m^3/min.)	2048 (58)	2214 (62.7)
Exhaust Temperature - °F (°C)	891 (477)	826 (441)
Maximum Allowable Back Pressure - in. H$_2$0 (kPa)	30 (7.5)	30 (7.5)
Minimum Exhaust Pipe Dia. - in. (mm)**	6 (152)	

Fuel System		
Fuel Consumption - gal./hr. (L/hr.)	20 (75.6)	20 (75.6)
Fuel Return - gal./hr. (L/hr.)		
Total Supply Fuel Flow - gal./hr. (L/hr.)		
Fuel Pressure - lb./in.^{2} (kPa)		
Minimum Line Size - Supply - (in.)	.50 Schedule 40 Steel Pipe	
Pipe Outer Diameter in. (mm)	.848 (0.33)	
Minimum Line Size - Return - (in.)	.375 Schedule 40 Steel Pipe	
Pipe Outer Diameter in. (mm)	.675 (0.26)	
Maximum Allowable Fuel Pump Suction With Clean Filter - in. H$_2$0 (mH$_2$0)	80 (2.0)	
Maximum Allowable Fuel Head above Fuel pump, Supply or Retrun - ft.(m)	6.6 (2.0)	
Fuel Filter Micron Size	2 (Secondary)	

Heater System	
Jacket Water Heater	Standard
Wattage (Nominal)	2500
Voltage - AC, 1P	230 (+5%, -10%)
Optional Voltage - AC, 1P	115 (+5%, -10%)
Lube Oil Heater Wattage (Required Option When Ambient is Below 40°F (4°C)	150

Induction Air System		
Air Cleaner Type	Indoors Service Only - Washable	
Air Intake Restriction Maximum Limit		
Dirty Air Cleaner - in. H$_2$0 (kPa)	25 (6.25)	25 (6.25)
Clean Air Cleaner - in. H$_2$0 (kPa)	15 (3.75)	15 (3.75)
Engine Air Flow - ft.^{3}/min. (m^3/min.)	848 (24)	971 (27.5)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)***	130 (54)	

Lubrication System		
Oil Pressure - normal - lb./in.^{2} (kPa)	37 (255)	41 (280)
In Pan Oil Temperature - °F (°C)	190-220 (88-104)	
Oil Pan Capacity - High - qt. (L)	48 (45)	
- Low - qt. (L)	39 (43)	
Total Oil Capacity with Filter - qt. (L)	41 (46)	

Performance		
BMEP - lb./in.^{2} (kPa)	346 (2386)	274 (1892)
Piston Speed - ft./min. (m/min.)	1570 (479)	1874 (571)
Mechanical Noise - dB(A) @ 1M	Consult Factory	
Power Curve	C132616	

*** Based On Nominal System. Flow Analysis Must Be Done To Assure Adherance To System Limitations. (Minimum Exhaust pipe Diameter is based on 15 feet of pipe, one elbow, and a silencer pressure drop no greter than one half the max. allowable back pressure.)*

**** Review For Power Deration If Air Entering Engine Exceeds °77F (25°C)*

Table 5.1A-12c

Tier 3 Emissions Data - John Deere Power Systems

Nameplate Rating Information

Clarke Model	JW6H-UFAD80
Power Rating (BHP / kW)	400 / 298
Certified Speed (RPM)	2100

Certificate Data

John Deere Engine Rating	6090HFC47B
Engine Model Year *	2009
EPA Family Name	9JDXL09.0114
EPA Certificate Number	JDX-NRCI-09-23
CARB Executive Order Number	U-R-004-0369
Emissions Label Part Number	R528939

* The Engine Model Year is listed on the emissions label.

Emissions Data * *

Units	g/hp-hr	g/kW-hr
CO	0.84	1.12
Pm	0.103	0.138
NOx	2.61	3.5
HC	0.104	0.14
NOx + HC	2.71	3.64
Test Engine	RG6090L015278	

* * The emission data listed is measured from the calibration engine under laboratory test conditions. It is intended to represent an "average" engine but is not a guarantee that all engines meet these values.

John Deere Power Systems
3801 W. Ridgeway Ave., PO Box 5100
Waterloo, Iowa USA 50704-5100

Table 5.1A-13 - SF$_6$ Loss GHG Emissions Estimate

Greenhouse Gas Emissions Calculator

SF6-Direct Fugitive Emissions
Electrical Equipment Used by Utilities

Emissions Analysis Period: Annual

System ID: OGS Circuit Breakers

Total capacity of system identified (lbs): 200 = 90.72 kg
Calculated losses of SF6 (lbs) for the device and reporting period:* (1) 1 = 0.45 kg

IPCC 2007 GWP Factor: 22800 (2)

Total Annual Emissions of SF6: **10.3** **CO2e metric tons**

* estimated loss rate from circuit breakers is 0.5% per year.
Ref (1) Statement of Basis, Russell City Energy Center, BAAQMD, 8-3-09.
Ref (2) BAAQMD Fact Sheet, Proposed GHG Fee Schedule, 2-5-08.

Table 5.1A-14   Oil Water Separator VOC Emissions Estimate

Usage Units: 1000 gallons

VOC Emissions Factor: 0.2 lbs VOC/usage unit or 0.2 lbs VOC/1000 gallons*

Maximum operating rate: 0.12 usage units/hr = 120 gals/hr

(0.2 lbs/1000 gallons) x (120 gallons/hr) = 0.024 lbs/hr

@ 24 hrs/day = 0.58 lbs/day

@365 days/yr = 0.11 tpy

*AP-42, Section 5.1, Table 5.1-2, 1/95.

Table 5.1A-15

Contra Costa Generating Station 2x1

Annual Emissions Calculations - Detail

Case Number	1	2	3
	PG&E Spec. 275 Hot Starts 25 Cold Starts [1]	6x16 1,500 hrs at Peak July [2]	6x24/1x18 1,500 hrs at Peak July [3]
Plant Dispatch			
Combustion Turbines/HRSGs (per unit unless noted)			
Number of Turbines/HRSGs	2	2	2
Minimum Load Hours - Natural Gas	-	-	-
Base Load ISO Hours - Natural Gas	3,657	3,933	6,924
Base Load Peak July Hours - Natural Gas	1,500	1,500	1,500
Total Hot Starts - Natural Gas	275	260	51
Total Warm Starts - Natural Gas	-	51	-
Total Cold Starts - Natural Gas	25	1	1
Total Shutdowns - Natural Gas	300	312	52
Startup/Shutdown Hours	233	229	39
Total Hours of Operation	5,390	5,662	8,463
Offline Hours	3,370	3,098	297
Annual Fuel Use, MMBtu (HHV) (all units)	22,480,757	23,625,816	35,397,277
Auxiliary Boiler			
Margin	20%	20%	20%
Operating Hours	4,324	3,992	403
Evaporative Fluid Cooler			
Operating Hours	1,500	1,500	1,500
Fire Pump			
Duration of Periodic Tests, mins	56	56	56
Frequency of Tests, tests/year	53	53	53
Load During Testing, %	100%	100%	100%
Operating Hours	49	49	49
Annual Fuel Use, gals/yr	989	989	989
Combustion Turbine/HRSG Emissions			
Minimum Load - Natural Gas			
NO_x, tons as NO_2	-	-	-
CO, tons	-	-	-
POC, tons as CH_4	-	-	-
PM_{10}, tons	-	-	-
SO_2, tons	-	-	-
CO_2, tons	-	-	-

Table 5.1A-15

RADBACK ENERGY

Contra Costa Generating Station 2x1

Annual Emissions Calculations - Detail

Case Number	1	2	3
	PG&E Spec. 275 Hot Starts 25 Cold Starts [1]	6x16 1,500 hrs at Peak July [2]	6x24/1x18 1,500 hrs at Peak July [3]
Base Load ISO - Natural Gas			
NO_x, tons as NO_2	20.8	22.4	39.4
CO, tons	8.4	9.1	16.0
POC, tons as CH_4	4.8	5.2	9.2
PM_{10}, tons	16.5	17.7	31.2
SO_2, tons	2.7	2.9	5.2
CO_2, tons	450,985.6	485,022.3	853,876.0
Base Load Peak July - Natural Gas			
NO_x, tons as NO_2	8.3	8.3	8.3
CO, tons	3.4	3.4	3.4
POC, tons as CH_4	1.9	1.9	1.9
PM_{10}, tons	6.8	6.8	6.8
SO_2, tons	1.1	1.1	1.1
CO_2, tons	179,825.6	179,825.6	179,825.6
Startups/Shutdowns - Natural Gas			
NO_x, tons as NO_2	10.1	9.6	1.6
CO, tons	37.2	35.2	6.0
POC, tons as CH_4	7.7	7.5	1.3
PM_{10}, tons	1.0	1.0	0.2
SO_2, tons	0.1	0.1	0.0
CO_2, tons	36,996	38,476	6,413
Total Emissions (each unit)			
NO_x, tons as NO_2	39.2	40.2	49.3
CO, tons	49.0	47.7	25.3
POC, tons as CH_4	14.4	14.6	12.4
PM_{10}, tons	24.3	25.5	38.1
SO_2, tons	3.9	4.1	6.3
CO_2, tons	667,808	703,324	1,040,114
Auxiliary Boiler			
NO_x, tons as NO_2	0.918	0.847	0.086
CO, tons	0.798	0.737	0.074
POC, tons as CH_4	0.229	0.211	0.021
PM_{10}, tons	0.766	0.707	0.071
SO_2, tons	0.305	0.282	0.028
CO_2, tons	12,786	11,807	1,192

Table 5.1A-15

Contra Costa Generating Station 2x1

Annual Emissions Calculations - Detail

Case Number	**1**	**2**	**3**
	PG&E Spec. 275 Hot Starts 25 Cold Starts [1]	**6x16 1,500 hrs at Peak July** [2]	**6x24/1x18 1,500 hrs at Peak July** [3]
Evaporative Fluid Cooler			
PM_{10}, tons	0.099	0.099	0.099
Fire Pump Emissions			
NO_x, tons as NO_2	0.0569	0.0569	0.0569
CO, tons	0.0183	0.0183	0.0183
POC, tons as CH_4	0.0023	0.0023	0.0023
PM_{10}, tons	0.0022	0.0022	0.0022
SO_2, tons	0.0001	0.0001	0.0001
Total Plant Emissions			
NO_x, tons as NO_2	79.3	81.4	98.8
CO, tons	98.8	96.1	50.8
POC, tons as CH_4	29.1	29.5	24.7
PM_{10}, tons	49.4	51.8	76.3
SO_2, tons	8.1	8.5	12.6
CO_2, tons (excluding fire pump)	1,348,401	1,418,455	2,081,421

Notes:

1. The Case 1 dispatch profile was created based on PG&E's 4/1/08 All-Source Long-Term Request for Offers, which requires 300 starts per year, of which, 25 are cold starts. The base load hours at Peak July Conditions provide an allowance for PM10 emissions from the evaporative fluid cooler, which will operate during hot weather.
2. The Case 2 dispatch profile assumes a typical 6x16 dispatch wherein the plant would be shutdown every night for 8 hours as well as all day on Sundays. The base load hours at Peak July Conditions provide an allowance for PM10 emissions from the evaporative fluid cooler, which will operate during hot weather.

3. The Case 3 dispatch profile was created for the purpose of developing a worst-case scenario for air permitting, wherein the plant would operate at base load for 24 hours per day, 6 days per week and 18 hours on Sundays. This case provides conservative estimates for those pollutants that are more heavily influenced by run hours, versus starts and stops.

Table 5.1A-15

Contra Costa Generating Station 2x1

Annual Emissions Calculations - Summary

Annual Emissions					
Case Number	**1**	**2**	**3**	**Maximum for Air Permit** [1]	**Maximum for ERC's or Mitigation** [2]
Description	**PG&E Spec. 275 Hot Starts 25 Cold Starts**	**6x16 1,500 hrs at Peak July**	**6x24/1x18 1,500 hrs of Peak July**		
Include in ERC/Mitigation Calc.?	**Yes**	**Yes**	**No**		
NO_X, tons as NO_2	79.3	81.4	**98.8**	98.8	81.4
CO, tons	**98.8**	96.1	50.8	98.8	98.8
POC, tons as CH_4	29.1	**29.5**	24.7	29.5	29.5
PM_{10}, tons	49.4	51.8	**76.3**	76.3	51.8
SO_2, tons	8.1	8.5	**12.6**	12.6	8.5
CO_2, tons	1,348,401.3	1,418,454.9	**2,081,420.9**	2,081,421	1,418,454.9
Total Fuel, MMBtu/hr	22,480,757.1	23,625,815.8	**35,397,277.0**	35,397,277	23,625,815.8

Notes:

1. Values for the purpose of permitting the maximum annual emissions for the project will be the maximum of Cases 1, 2, and 3.
2. Where ERCs or other mitigation is required for offsetting emissions, such offsets will be based on the maximum of Cases 1 and 2. If the plant owner later chooses to operate on an annual basis where any of the emissions requiring ERCs or other mitigation exceed these values, it will be necessary for to provide additional offsets/mitigation at that time.

APPENDIX 5.1B

Modeling Support Data

APPENDIX 5.1B

Modeling Support Data

Tables presented in this Appendix are as follows:

In addition, this appendix contains the following figures:

Modeling input/output files are included in the enclosed CD’s.

Table 5.1B-1 (11 Pages)

ANTIOCH PUMP PLANT 3, CALIFORNIA (040232)

Period of Record Monthly Climate Summary

Period of Record : 3/ 1/1955 to 12/31/2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Average Max. Temperature (F)	53.7	60.2	65.4	71.5	78.7	86.1	91.2	90.0	86.1	77.4	64.3	54.7	73.3
Average Min. Temperature (F)	37.1	41.0	43.4	46.3	51.4	56.2	57.5	56.8	55.2	50.2	43.1	37.3	48.0
Average Total Precipitation (in.)	2.78	2.39	1.96	0.90	0.37	0.09	0.02	0.04	0.19	0.65	1.58	2.20	13.17
Average Total SnowFall (in.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average Snow Depth (in.)	0	0	0	0	0	0	0	0	0	0	0	0	0

Percent of possible observations for period of record.
Max. Temp.: 98% Min. Temp.: 98.4% Precipitation: 98.8% Snowfall: 99.1% Snow Depth: 99.1%
Check Station Metadata or Metadata graphics for more detail about data completeness.

Western Regional Climate Center, wrcc@dri.edu

ANTIOCH PUMP PLANT 3, CALIFORNIA

NCDC 1971-2000 Monthly Normals

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Monthly
Mean Max. Temperature (F)	53.5	59.9	64.6	71.1	78.5	85.6	90.7	89.8	85.9	77.5	63.9	54.3	72.9
Highest Mean Max. Temperature (F)	59.2	64.4	69.8	77.4	86.1	93.3	96.2	94.5	91.7	82.9	71.2	59.6	96.2
Year Highest Occurred	1976	1991	1997	1987	1992	1981	1988	1996	1984	1991	1995	1999	1988
Lowest Mean Max. Temperature (F)	46.7	56.0	60.0	64.0	67.9	79.6	85.3	83.5	79.9	72.5	56.6	47.8	46.7
Year Lowest Occurred	1985	1989	1991	1975	1998	1998	1987	1976	1986	1984	1982	1985	1985
Mean Temperature (F)	45.7	50.6	54.5	59.2	65.2	71.1	74.4	73.7	71.0	64.3	53.8	45.7	60.8
Highest Mean Temperature (F)	51.4	54.7	58.2	64.2	71.9	77.5	79.8	77.5	75.6	69.2	59.8	51.9	79.8
Year Highest Occurred	1995	1991	1993	1987	1997	1981	1988	1992	1984	1991	1995	1995	1988
Lowest Mean Temperature (F)	39.1	47.2	50.3	51.8	59.1	65.6	70.4	69.9	67.1	58.6	48.3	40.3	39.1
Year Lowest Occurred	1972	1971	1985	1975	1998	1982	1975	1980	1986	1971	1982	1972	1972
Mean Min. Temperature (F)	37.8	41.3	44.3	47.2	51.9	56.5	58.1	57.6	56.0	51.1	43.6	37.1	48.5
Highest Mean Min. Temperature (F)	46.1	46.2	48.6	51.9	58.7	62.8	63.4	61.8	60.4	56.1	48.7	44.3	63.4
Year Highest Occurred	1995	1986	1993	1990	1997	1993	1988	1990	1997	1992	1997	1995	1988
Lowest Mean Min. Temperature (F)	30.9	35.6	39.9	39.6	47.5	50.9	53.5	53.0	50.3	42.4	38.5	31.0	30.9
Year Lowest Occurred	1972	1974	1975	1975	1975	1982	1975	1980	1972	1971	1971	1976	1972
Mean Precipitation (in.)	2.72	2.51	2.16	0.73	0.47	0.09	0.03	0.03	0.24	0.76	1.70	1.89	13.33
Highest Precipitation (in.)	6.97	9.03	6.26	3.31	2.09	0.64	0.46	0.74	1.84	4.17	4.56	5.05	9.03
Year Highest Occurred	1993	1998	1983	1983	1998	1995	1980	1976	1989	1972	1972	1995	1998
Lowest Precipitation (in.)	0.13	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Year Lowest Occurred	1984	1995	1972	1997	1999	1999	2000	2000	1997	1995	1995	1989	1997
Heating Degree Days (F)	600.	404.	332.	206.	99.	18.	4.	1.	10.	99.	344.	597.	2714.
Cooling Degree Days (F)	0.	0.	4.	30.	106.	200.	296.	270.	190.	77.	6.	0.	1179.

Western Regional Climate Center, wrcc@dri.edu

ANTIOCH PUMP PLANT 3, CALIFORNIA

Period of Record Daily Climate Summary

Daily Records for station 040232 ANTIOCH PUMP PLANT 3 state: ca

For temperature and precipitation, multi-day accumulations
are not considered either for records or averages.
The year given is the year of latest occurrence.

Period requested -- Begin : 1/ 1/1890 -- End : 12/31/2008
Period used -- Begin : 3/ 1/1955 -- End : 12/31/2008

Cooling degree threshold = 65.00 Heating degree threshold = 65.00

AVG Multi-year unsmoothed average of the indicated quantity
HI Highest value of indicated quantity for this day of year
LO Lowest value of indicated quantity for this day of year
YR Latest year of occurrence of the extreme value
NO Number of years with data for this day of year.
Units: English (inches and degrees F)

		Maximum Temperature						Minimum Temperature						Precipitation				Snowfall				Snowdepth			
MO	DY	AVG	NO	HI	YR	LO	YR	AVG	NO	HI	YR	LO	YR	AVG	NO	HIGH	YR	AVG	NO	HIGH	YR	AVG	NO	HIGH	YR
1	1	52	50	66	1997	38	1962	35	50	58	1997	21	1979	0.109	49	1.38	2005	0.00	51	0.0	2008	0.0	50	0.	2008
1	2	51	50	65	2007	36	1983	35	50	56	1997	22	1961	0.120	49	1.90	2005	0.00	51	0.0	2008	0.0	51	0.	2008
1	3	51	50	62	1998	38	1963	35	50	48	1986	22	1968	0.066	49	0.62	1965	0.00	51	0.0	2008	0.0	51	0.	2008
1	4	51	50	65	1996	36	1961	35	50	48	1986	23	1968	0.110	49	1.80	2008	0.00	51	0.0	2008	0.0	51	0.	2008
1	5	52	50	65	2003	40	1974	36	49	53	1986	23	1968	0.132	49	2.80	1982	0.00	51	0.0	2008	0.0	51	0.	2008
1	6	51	50	68	1986	33	1961	37	50	50	1965	25	1972	0.073	49	1.10	1959	0.00	51	0.0	2008	0.0	51	0.	2008
1	7	52	50	64	1986	40	1969	37	50	48	1966	25	1972	0.049	49	0.79	1993	0.00	51	0.0	2008	0.0	51	0.	2008
1	8	52	50	61	2007	37	1968	37	50	46	2002	25	1982	0.045	49	0.52	1993	0.00	51	0.0	2008	0.0	51	0.	2008
1	9	53	50	64	1990	37	1968	37	50	50	1978	26	1957	0.080	49	0.84	1959	0.00	51	0.0	2008	0.0	51	0.	2008
1	10	54	50	67	1962	40	1999	37	50	52	1959	23	1957	0.106	49	1.90	1995	0.00	51	0.0	2008	0.0	51	0.	2008
1	11	53	50	65	1962	36	1999	38	49	49	2000	28	1982	0.069	49	0.86	1979	0.00	51	0.0	2008	0.0	51	0.	2008
1	12	52	50	67	1980	37	1972	38	49	52	1998	26	1964	0.048	49	0.36	1998	0.00	51	0.0	2008	0.0	51	0.	2008
1	13	53	50	69	1980	38	1972	37	50	59	1980	21	1963	0.114	49	2.08	1993	0.00	51	0.0	2008	0.0	51	0.	2008
1	14	53	50	65	1980	40	1997	37	50	55	1980	21	1963	0.090	49	0.99	1978	0.00	51	0.0	2008	0.0	51	0.	2008
1	15	53	50	65	1980	40	1985	37	48	51	1956	22	1963	0.118	49	1.48	1979	0.00	51	0.0	2008	0.0	51	0.	2008
1	16	54	50	65	1966	41	1977	38	49	50	1998	24	1963	0.079	49	0.69	1996	0.00	51	0.0	2008	0.0	51	0.	2008
1	17	55	50	67	1970	39	1972	38	49	52	1970	25	1963	0.045	49	0.74	1978	0.00	51	0.0	2008	0.0	51	0.	2008
1	18	54	50	70	1986	37	1972	38	50	53	1999	25	1966	0.054	49	0.88	1993	0.00	51	0.0	2008	0.0	51	0.	2008
1	19	54	50	67	1976	40	1972	38	50	53	1999	24	1963	0.082	49	1.24	1969	0.00	51	0.0	2008	0.0	51	0.	2008
1	20	55	51	68	1991	40	1992	39	51	54	1999	25	1963	0.070	48	0.53	1969	0.00	51	0.0	2008	0.0	51	0.	2008
1	21	55	51	65	1993	39	1992	37	50	53	1969	24	1966	0.145	48	2.00	1964	0.00	51	0.0	2008	0.0	51	0.	2008

1	22	55	51	67	1976	35	1962	38	51	56	1970	23	1962	0.082	48	1.50	1967	0.00	51	0.0	2008	0.0	51	0.	2008
1	23	55	51	68	1968	41	2008	37	51	55	1970	23	1962	0.124	49	1.62	2000	0.00	51	0.0	2008	0.0	51	0.	2008
1	24	55	51	65	1976	36	1992	37	51	49	2000	20	1962	0.133	49	1.65	2000	0.00	51	0.0	2008	0.0	51	0.	2008
1	25	56	51	67	1976	40	1992	37	51	51	2003	22	1962	0.106	49	0.94	1997	0.00	51	0.0	2008	0.0	51	0.	2008
1	26	56	50	66	1976	44	1963	38	50	52	1956	26	1962	0.106	48	1.33	1961	0.00	51	0.0	2008	0.0	51	0.	2008
1	27	56	51	66	2003	44	1980	38	51	47	2003	29	1985	0.092	49	1.40	1983	0.00	51	0.0	2008	0.0	51	0.	2008
1	28	56	51	67	1962	39	1963	38	51	49	1997	28	1975	0.052	49	0.78	1981	0.00	51	0.0	2008	0.0	51	0.	2008
1	29	55	50	65	1976	42	1963	38	50	50	1995	28	1969	0.068	49	0.62	1983	0.00	51	0.0	2008	0.0	51	0.	2008
1	30	56	50	65	1976	42	1971	38	50	52	1995	27	1972	0.129	49	1.52	1968	0.00	51	0.0	2008	0.0	51	0.	2008
1	31	55	50	72	1976	42	1971	38	50	52	1995	26	1957	0.093	49	1.17	1996	0.00	51	0.0	2008	0.0	51	0.	2008
2	1	57	50	71	1976	37	1972	39	50	56	1963	28	1985	0.065	49	1.05	1963	0.00	51	0.0	2008	0.0	51	0.	2008
2	2	57	51	72	1976	44	1971	39	51	54	1963	26	1972	0.067	51	0.45	1975	0.00	51	0.0	2008	0.0	51	0.	2008
2	3	57	50	73	1976	44	1966	39	50	54	1963	27	1972	0.082	51	2.33	1998	0.00	51	0.0	2008	0.0	51	0.	2008
2	4	57	50	71	1976	44	1965	38	51	53	1963	26	1957	0.050	51	0.46	1986	0.00	51	0.0	2008	0.0	51	0.	2008
2	5	58	51	66	1993	44	1962	38	51	50	1996	26	1985	0.088	51	1.05	1991	0.00	51	0.0	2008	0.0	51	0.	2008
2	6	58	50	68	1964	40	1976	40	50	51	1960	25	1989	0.082	51	1.08	1969	0.00	51	0.0	2008	0.0	51	0.	2008
2	7	59	50	71	1963	42	1989	40	50	52	1960	26	1989	0.099	51	0.97	1978	0.00	51	0.0	2008	0.0	51	0.	2008
2	8	59	50	72	2006	44	1989	41	49	53	1960	28	1989	0.095	51	1.33	1998	0.00	51	0.0	2008	0.0	51	0.	2008
2	9	59	50	71	1963	44	1989	42	49	52	1963	30	1974	0.119	51	0.88	1962	0.00	51	0.0	2008	0.0	51	0.	2008
2	10	59	51	69	1988	43	1989	42	51	52	2007	30	1974	0.072	51	0.75	1960	0.00	51	0.0	2008	0.0	51	0.	2008
2	11	60	51	71	1988	44	1989	41	51	51	1987	29	1982	0.095	51	0.75	2007	0.00	51	0.0	2008	0.0	51	0.	2008
2	12	60	51	72	1996	51	1959	41	51	54	1958	30	1965	0.068	51	0.99	1992	0.00	51	0.0	2008	0.0	51	0.	2008
2	13	60	51	70	2006	47	1978	42	51	53	1987	30	1965	0.136	51	1.88	1987	0.00	51	0.0	2008	0.0	51	0.	2008
2	14	61	51	72	1977	51	2007	42	51	53	2000	26	1966	0.103	51	1.32	1986	0.00	51	0.0	2008	0.0	51	0.	2008
2	15	61	51	76	1977	48	1990	41	51	52	1991	28	1990	0.127	51	1.35	2005	0.00	51	0.0	2008	0.0	51	0.	2008
2	16	61	51	75	2007	47	1990	41	50	53	1986	29	1966	0.118	51	1.00	1959	0.00	51	0.0	2008	0.0	51	0.	2008
2	17	61	51	74	1977	49	2006	42	50	55	1996	30	1966	0.104	51	0.94	1980	0.00	51	0.0	2008	0.0	51	0.	2008
2	18	62	51	76	1977	48	1990	42	50	57	1986	30	1975	0.073	51	0.57	1986	0.00	51	0.0	2008	0.0	51	0.	2008
2	19	61	51	75	1977	49	2006	43	51	55	1986	33	1964	0.155	51	1.87	1958	0.00	51	0.0	2008	0.0	51	0.	2008
2	20	62	51	76	1964	45	1994	42	51	52	1968	32	1990	0.079	51	0.68	1994	0.00	51	0.0	2008	0.0	51	0.	2008
2	21	61	51	72	1965	46	1994	42	50	53	1968	29	1967	0.092	51	0.95	1979	0.00	51	0.0	2008	0.0	51	0.	2008
2	22	62	51	74	1985	50	1959	42	51	52	1968	29	1967	0.068	51	0.91	2000	0.00	51	0.0	2008	0.0	51	0.	2008
2	23	62	51	76	1985	52	2008	41	51	54	1968	29	1975	0.059	51	0.76	1957	0.00	51	0.0	2008	0.0	51	0.	2008
2	24	62	51	74	1968	51	1969	41	51	53	1958	30	1974	0.040	51	0.59	1983	0.00	51	0.0	2008	0.0	51	0.	2008
2	25	62	51	73	1991	52	1996	42	51	52	1995	31	1962	0.073	51	1.15	2004	0.00	51	0.0	2008	0.0	51	0.	2008
2	26	62	51	75	1963	51	1996	42	51	52	1957	30	1962	0.054	51	0.64	2006	0.00	51	0.0	2008	0.0	51	0.	2008
2	27	62	51	73	1992	45	1962	42	51	55	1988	29	1962	0.055	51	0.57	2006	0.00	51	0.0	2008	0.0	51	0.	2008
2	28	63	51	76	1985	45	1996	42	51	51	1995	29	1962	0.068	51	1.12	1973	0.00	51	0.0	2008	0.0	51	0.	2008
2	29	64	14	70	2008	56	1996	44	14	52	1988	38	1964	0.036	14	0.14	2000	0.00	14	0.0	2008	0.0	14	0.	2008
3	1	62	50	75	1985	52	1962	42	50	51	1995	31	1955	0.102	46	0.79	1991	0.00	50	0.0	2008	0.0	50	0.	2008
3	2	62	50	77	1961	53	1976	43	50	54	1983	28	1971	0.087	47	0.94	1978	0.00	50	0.0	2008	0.0	50	0.	2008
3	3	62	50	77	1968	45	1976	42	50	52	1992	29	1966	0.058	47	0.66	1995	0.00	50	0.0	2008	0.0	50	0.	2008
3	4	63	50	76	1959	52	1973	43	49	54	1994	27	1966	0.042	47	0.42	1973	0.00	50	0.0	2008	0.0	50	0.	2008
3	5	63	50	76	1959	49	1989	42	50	53	1987	31	1976	0.069	47	0.65	1970	0.00	50	0.0	2008	0.0	50	0.	2008
3	6	63	50	76	1972	50	1985	42	50	52	1994	28	1971	0.082	47	0.96	1992	0.00	50	0.0	2008	0.0	50	0.	2008
3	7	64	50	80	1972	53	1956	42	50	58	1986	31	1971	0.039	47	0.39	1975	0.00	50	0.0	2008	0.0	50	0.	2008
3	8	65	50	80	1972	52	1974	43	50	57	1986	32	1969	0.067	47	0.85	1986	0.00	50	0.0	2008	0.0	50	0.	2008

```
3  9  65  50  75 1993  57 1998  43  50  55 2005  30 1974 0.045  47  0.58 1978  0.00  50  0.0 2008  0.0  50  0. 2008
3 10  65  50  78 2005  58 1999  44  50  56 1989  31 1977 0.071  47  1.10 1995  0.00  50  0.0 2008  0.0  50  0. 2008
3 11  65  50  79 2005  53 2006  44  50  55 1989  33 1969 0.081  47  0.80 1983  0.00  50  0.0 2008  0.0  50  0. 2008
3 12  66  50  78 2007  50 2006  44  50  54 1972  35 1968 0.043  47  0.67 1996  0.00  50  0.0 2008  0.0  50  0. 2008
3 13  65  50  78 2007  47 1969  44  49  57 1984  30 1956 0.145  47  1.17 1983  0.00  50  0.0 2008  0.0  50  0. 2008
3 14  64  50  80 1994  50 1975  42  50  53 1993  30 1977 0.082  47  1.00 1975  0.00  50  0.0 2008  0.0  50  0. 2008
3 15  65  50  79 2007  47 1971  43  50  52 1994  32 1969 0.052  47  0.62 1986  0.00  50  0.0 2008  0.0  50  0. 2008
3 16  65  50  78 2007  53 1986  43  50  55 1998  34 1957 0.104  47  1.07 1977  0.00  50  0.0 2008  0.0  50  0. 2008
3 17  65  50  82 1972  53 1979  44  50  56 1993  32 1963 0.058  47  0.60 1993  0.00  50  0.0 2008  0.0  50  0. 2008
3 18  67  50  81 1964  54 1991  44  50  53 1998  32 1963 0.028  47  0.32 2005  0.00  50  0.0 2008  0.0  50  0. 2008
3 19  67  51  78 1996  55 1991  44  51  53 1989  34 1963 0.033  47  0.36 1989  0.00  51  0.0 2008  0.0  51  0. 2008
3 20  67  51  80 1960  52 1973  43  51  53 1997  34 1963 0.028  47  0.60 1973  0.00  51  0.0 2008  0.0  51  0. 2008
3 21  67  51  81 1960  54 1973  43  49  54 1997  32 1964 0.076  47  0.68 2005  0.00  51  0.0 2008  0.0  51  0. 2008
3 22  67  51  78 1965  51 1973  44  50  54 1998  35 1975 0.090  47  1.06 2005  0.00  51  0.0 2008  0.0  51  0. 2008
3 23  67  51  78 2007  47 1964  44  51  53 1993  35 1994 0.075  47  0.78 1995  0.00  51  0.0 2008  0.0  51  0. 2008
3 24  66  51  79 1984  52 1995  43  51  56 1997  34 1957 0.060  47  0.53 1999  0.00  51  0.0 2008  0.0  51  0. 2008
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4 24  71  50  88 1981  55 1991  46  50  58 1976  32 1964 0.027  52  0.34 1983  0.00  52  0.0 2008  0.0  52  0. 2008
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7	27	92	52	106	1973	79	1965	57	52	66	1988	48	1972	0.000	52	0.00	2008	0.00	52	0.0	2008	0.0	52	0.	2008

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7	31	91	52	108	1977	72	1966	58	52	69	1980	49	1981	0.004	52	0.20	1966	0.00	52	0.0	2008	0.0	52	0.	2008
8	1	92	52	104	1996	77	1976	58	52	69	2000	46	1959	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	2	92	51	103	1995	78	2004	57	52	67	2000	46	1959	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	3	92	52	103	1987	75	2002	57	52	67	1998	49	1963	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	4	91	52	106	1998	78	1976	57	52	71	1998	48	1963	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	5	91	52	109	1998	78	1962	56	52	68	1998	49	1979	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	6	91	52	104	1997	76	2007	57	52	70	1990	43	1958	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	7	92	52	104	1997	77	1962	59	52	69	1982	51	1975	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	8	92	52	106	1981	78	1962	58	52	69	1990	48	1979	0.001	53	0.04	1989	0.00	53	0.0	2008	0.0	53	0.	2008
8	9	92	52	104	1990	75	1963	58	52	73	1990	47	1980	0.001	53	0.05	1962	0.00	53	0.0	2008	0.0	53	0.	2008
8	10	93	52	105	1990	78	1999	58	52	69	1965	50	1960	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	11	92	51	106	1996	78	1999	57	52	66	1990	51	1989	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	12	91	51	106	1996	79	1965	57	52	68	1998	49	1957	0.005	53	0.28	1965	0.00	53	0.0	2008	0.0	53	0.	2008
8	13	91	51	103	1998	77	1988	57	52	69	1984	50	1974	0.001	53	0.03	1991	0.00	53	0.0	2008	0.0	53	0.	2008
8	14	90	51	105	1996	70	1968	57	52	70	1996	48	1955	0.001	53	0.05	1976	0.00	53	0.0	2008	0.0	53	0.	2008
8	15	89	52	104	1996	73	1976	57	52	67	1992	48	1955	0.003	53	0.16	1976	0.00	53	0.0	2008	0.0	53	0.	2008
8	16	89	51	101	1983	74	1976	56	51	67	1992	45	1955	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	17	90	51	101	1992	75	1976	57	51	66	1966	46	1955	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	18	89	52	101	1967	75	1985	56	52	66	1990	48	1957	0.004	53	0.17	1976	0.00	53	0.0	2008	0.0	53	0.	2008
8	19	88	51	100	1984	69	1976	56	51	65	1967	47	1955	0.005	53	0.23	1976	0.00	53	0.0	2008	0.0	53	0.	2008
8	20	88	52	104	1992	72	1959	57	52	66	2008	49	1970	0.001	53	0.04	1983	0.00	53	0.0	2008	0.0	53	0.	2008
8	21	89	52	101	1992	75	1959	56	52	71	1992	45	1959	0.007	53	0.35	2003	0.00	53	0.0	2008	0.0	53	0.	2008
8	22	88	52	100	1999	74	1968	56	52	64	2000	47	1959	0.011	53	0.45	1968	0.00	53	0.0	2008	0.0	53	0.	2008
8	23	89	52	98	1982	78	1976	56	52	64	1999	47	1970	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	24	89	52	100	1974	76	1963	56	52	65	1989	50	1980	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	25	89	51	102	1999	76	1990	57	52	67	1993	47	1963	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	26	88	52	103	1988	76	1990	56	52	69	1988	45	1955	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	27	88	52	104	1988	76	1975	57	52	69	1999	46	1970	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	28	89	52	103	1981	75	1975	57	52	70	2007	45	1955	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	29	90	52	105	2008	81	2000	57	52	69	1990	44	1955	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	30	89	51	103	2007	72	2000	57	52	71	2007	45	1957	0.000	53	0.00	2008	0.00	53	0.0	2008	0.0	53	0.	2008
8	31	88	51	102	1976	73	1966	56	52	66	2007	45	1960	0.004	53	0.15	1964	0.00	53	0.0	2008	0.0	52	0.	2008
9	1	89	54	104	1955	68	2000	57	53	70	1985	48	1970	0.001	54	0.08	2000	0.00	54	0.0	2008	0.0	53	0.	2008
9	2	90	54	108	1955	71	2000	56	53	66	1993	47	1959	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	3	90	54	108	1955	76	2000	56	53	68	2004	47	1970	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	4	89	54	109	1955	75	2000	56	53	65	2007	46	1960	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	5	90	54	106	1988	79	1970	57	53	68	2008	46	1964	0.001	54	0.05	1970	0.00	54	0.0	2008	0.0	54	0.	2008
9	6	90	54	107	1988	73	1978	57	54	70	1998	48	1973	0.001	54	0.04	1978	0.00	54	0.0	2008	0.0	54	0.	2008
9	7	89	54	103	1958	69	1965	57	54	69	1998	48	1978	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	8	88	54	108	1957	74	1985	56	54	69	1984	48	1965	0.000	54	0.01	1958	0.00	54	0.0	2008	0.0	54	0.	2008
9	9	88	54	102	1984	72	1985	56	54	64	1997	45	1964	0.005	54	0.16	1985	0.00	54	0.0	2008	0.0	54	0.	2008
9	10	87	54	103	1984	69	1978	55	54	66	1976	47	1964	0.000	54	0.01	1978	0.00	54	0.0	2008	0.0	54	0.	2008
9	11	86	54	100	1960	73	1985	56	54	64	1997	46	1962	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	12	86	54	99	2006	72	1976	56	54	67	1988	45	1972	0.001	54	0.04	1976	0.00	54	0.0	2008	0.0	54	0.	2008

9	13	87	54	105	1979	75	1986	55	54	71	2000	43	1970	0.002	54	0.10	1963	0.00	54	0.0	2008	0.0	54	0.	2008
9	14	85	54	104	1971	72	1980	54	54	63	2000	41	1980	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	15	85	54	100	1983	71	1980	55	54	69	1971	43	1970	0.000	54	0.02	1955	0.00	54	0.0	2008	0.0	54	0.	2008
9	16	85	54	103	1979	69	1982	54	54	64	1989	46	1970	0.005	54	0.15	1982	0.00	54	0.0	2008	0.0	54	0.	2008
9	17	84	54	102	1979	62	1977	56	54	66	2002	44	1972	0.014	54	0.42	1989	0.00	54	0.0	2008	0.0	54	0.	2008
9	18	84	54	98	2000	68	1989	56	54	71	2000	44	1965	0.015	54	0.50	1959	0.00	54	0.0	2008	0.0	54	0.	2008
9	19	84	54	101	2000	66	1959	54	54	69	1984	43	1965	0.056	54	1.25	1959	0.00	54	0.0	2008	0.0	54	0.	2008
9	20	84	54	100	1958	70	1986	55	54	67	1983	43	1965	0.001	54	0.07	1977	0.00	54	0.0	2008	0.0	54	0.	2008
9	21	85	54	98	1990	72	2007	54	54	68	1983	43	1960	0.000	54	0.00	2008	0.00	54	0.0	2008	0.0	54	0.	2008
9	22	86	54	103	2003	73	2000	54	54	65	1983	47	1965	0.003	54	0.16	1999	0.00	54	0.0	2008	0.0	54	0.	2008
9	23	85	54	95	1957	71	2007	54	54	64	1989	44	1960	0.001	54	0.05	1973	0.00	54	0.0	2008	0.0	54	0.	2008
9	24	85	54	99	1964	71	2007	54	53	64	1997	46	1977	0.014	53	0.42	1982	0.00	54	0.0	2008	0.0	54	0.	2008
9	25	85	54	99	1975	71	1986	55	54	65	1992	44	1972	0.005	54	0.22	1982	0.00	54	0.0	2008	0.0	54	0.	2008
9	26	84	54	97	1978	68	1998	54	54	66	1999	43	1955	0.009	54	0.31	1982	0.00	54	0.0	2008	0.0	54	0.	2008
9	27	84	54	97	1963	63	1998	55	54	70	1999	45	1955	0.016	54	0.34	1998	0.00	54	0.0	2008	0.0	54	0.	2008
9	28	83	54	97	1968	67	1965	54	53	68	1999	44	1964	0.002	54	0.04	1961	0.00	54	0.0	2008	0.0	54	0.	2008
9	29	83	54	98	1966	70	1976	54	54	66	1999	42	1955	0.025	54	0.85	1976	0.00	54	0.0	2008	0.0	54	0.	2008
9	30	84	54	102	1966	67	1971	54	54	64	1999	44	1959	0.012	54	0.63	1983	0.00	54	0.0	2008	0.0	54	0.	2008
10	1	83	54	99	2001	68	1971	54	53	62	1992	40	1971	0.001	54	0.05	1983	0.00	54	0.0	2008	0.0	54	0.	2008
10	2	83	54	98	1980	62	2004	53	53	62	1974	41	1971	0.009	54	0.48	1976	0.00	54	0.0	2008	0.0	54	0.	2008
10	3	82	54	100	1980	68	1989	53	54	67	1990	43	1973	0.006	54	0.24	1981	0.00	54	0.0	2008	0.0	54	0.	2008
10	4	82	54	101	1980	70	1981	53	54	68	1985	42	1973	0.000	54	0.01	1972	0.00	54	0.0	2008	0.0	54	0.	2008
10	5	82	54	102	1964	69	2007	53	53	66	1987	37	1969	0.010	54	0.42	1994	0.00	54	0.0	2008	0.0	54	0.	2008
10	6	81	53	97	1987	67	1993	52	53	67	1987	40	1969	0.001	54	0.03	1975	0.00	54	0.0	2008	0.0	54	0.	2008
10	7	82	54	98	1964	71	1957	53	53	64	1992	41	1969	0.015	54	0.70	1973	0.00	54	0.0	2008	0.0	54	0.	2008
10	8	81	54	97	1964	58	1973	52	53	63	1996	40	1964	0.008	54	0.43	1973	0.00	54	0.0	2008	0.0	54	0.	2008
10	9	80	54	97	1996	60	1973	53	53	65	1996	41	1968	0.010	54	0.39	1997	0.00	54	0.0	2008	0.0	54	0.	2008
10	10	80	54	94	1992	64	2000	52	54	67	1991	40	1968	0.026	54	0.43	1957	0.00	54	0.0	2008	0.0	54	0.	2008
10	11	79	53	96	1991	62	2000	51	53	67	1991	43	1985	0.046	54	0.71	1972	0.00	54	0.0	2008	0.0	54	0.	2008
10	12	79	54	96	1991	64	2000	51	53	61	1991	42	1960	0.011	54	0.30	1972	0.00	54	0.0	2008	0.0	54	0.	2008
10	13	79	54	96	1991	58	2007	52	52	64	1990	43	1981	0.070	53	3.03	1962	0.00	54	0.0	2008	0.0	54	0.	2008
10	14	79	53	92	1978	65	1968	51	53	60	1994	40	1968	0.049	54	1.46	1962	0.00	54	0.0	2008	0.0	54	0.	2008
10	15	78	53	93	1991	62	1972	50	53	61	1999	38	1966	0.023	53	0.64	1972	0.00	54	0.0	2008	0.0	54	0.	2008
10	16	77	53	95	1961	58	1969	50	53	64	1999	41	1970	0.040	54	1.22	1972	0.00	54	0.0	2008	0.0	54	0.	2008
10	17	77	53	96	1961	58	1984	49	53	61	1999	36	1971	0.021	54	0.76	1984	0.00	54	0.0	2008	0.0	54	0.	2008
10	18	78	53	93	1961	62	1971	49	53	58	1989	35	1971	0.005	54	0.21	1969	0.00	54	0.0	2008	0.0	54	0.	2008
10	19	77	53	88	1991	64	1984	49	53	59	1995	36	1971	0.038	54	1.75	2004	0.00	54	0.0	2008	0.0	54	0.	2008
10	20	76	53	90	1991	60	2004	48	52	61	2003	39	1971	0.001	53	0.05	1970	0.00	54	0.0	2008	0.0	54	0.	2008
10	21	76	54	91	1991	62	2004	49	54	62	1991	39	1971	0.008	53	0.36	1985	0.00	54	0.0	2008	0.0	54	0.	2008
10	22	75	54	87	2003	55	1985	49	54	59	1987	38	1971	0.010	54	0.25	1989	0.00	54	0.0	2008	0.0	54	0.	2008
10	23	76	54	88	1964	63	1972	49	53	61	1987	36	1961	0.021	54	0.65	1973	0.00	54	0.0	2008	0.0	54	0.	2008
10	24	74	54	88	1965	59	2004	49	54	60	1982	38	1956	0.032	54	0.75	2004	0.00	54	0.0	2008	0.0	54	0.	2008
10	25	75	54	90	1965	64	1970	49	54	62	1982	38	1975	0.021	54	0.58	1998	0.00	54	0.0	2008	0.0	54	0.	2008
10	26	74	54	87	2003	60	2000	49	54	58	1993	33	1971	0.044	53	1.29	1991	0.00	54	0.0	2008	0.0	54	0.	2008
10	27	73	54	89	1993	60	1962	48	54	62	1987	35	1971	0.006	54	0.14	1956	0.00	54	0.0	2008	0.0	54	0.	2008
10	28	72	54	88	2003	60	1962	48	54	61	1987	36	1976	0.026	54	0.37	1987	0.00	54	0.0	2008	0.0	54	0.	2008
10	29	72	53	90	2003	55	1971	48	54	59	1987	35	1975	0.034	53	1.03	1964	0.00	54	0.0	2008	0.0	54	0.	2008

10	30	70	54	82	1965	54	1996	46	54	57	1983	28	1971	0.041	54	0.60	1996	0.00	54	0.0	2008	0.0	54	0.	2008
10	31	70	54	83	1965	57	1996	46	54	61	1997	32	1972	0.015	54	0.31	1974	0.00	54	0.0	2008	0.0	54	0.	2008
11	1	71	52	84	1967	59	2003	45	52	60	1997	33	1975	0.017	52	0.62	2008	0.00	52	0.0	2008	0.0	52	0.	2008
11	2	71	52	85	1967	57	1956	46	52	63	1992	35	1959	0.013	52	0.30	1964	0.00	52	0.0	2008	0.0	52	0.	2008
11	3	70	52	84	1967	57	2003	46	52	61	1992	32	1971	0.039	52	0.92	1968	0.00	52	0.0	2008	0.0	52	0.	2008
11	4	69	52	82	1967	57	2004	46	52	60	1997	34	1971	0.024	52	0.56	1979	0.00	52	0.0	2008	0.0	52	0.	2008
11	5	70	52	80	1976	50	1996	46	52	55	1967	35	1971	0.023	52	0.35	1994	0.00	52	0.0	2008	0.0	52	0.	2008
11	6	69	52	80	1958	52	1994	46	52	56	2006	32	1957	0.098	52	2.00	1994	0.00	52	0.0	2008	0.0	52	0.	2008
11	7	69	52	80	2006	54	1966	46	52	55	2006	33	1957	0.063	52	1.76	2002	0.00	52	0.0	2008	0.0	52	0.	2008
11	8	69	52	80	1958	57	1964	46	52	59	2006	32	1959	0.040	52	1.06	1984	0.00	52	0.0	2008	0.0	52	0.	2008
11	9	68	52	83	1955	58	2005	45	52	56	2005	32	1959	0.019	52	0.35	1964	0.00	52	0.0	2008	0.0	52	0.	2008
11	10	67	52	82	1976	48	1982	46	52	54	1988	32	1959	0.073	52	0.96	1982	0.00	52	0.0	2008	0.0	52	0.	2008
11	11	66	52	83	1955	53	1994	45	52	59	1973	32	1959	0.100	52	1.20	1983	0.00	52	0.0	2008	0.0	52	0.	2008
11	12	65	52	77	1956	48	1982	45	52	56	2008	32	1978	0.038	52	0.71	1973	0.00	52	0.0	2008	0.0	52	0.	2008
11	13	65	52	78	1956	52	1982	44	52	56	2008	28	1985	0.086	52	0.92	1984	0.00	52	0.0	2008	0.0	52	0.	2008
11	14	64	52	80	1995	47	1955	44	52	57	2005	30	1985	0.106	52	2.01	1981	0.00	52	0.0	2008	0.0	52	0.	2008
11	15	63	52	76	1995	46	1982	43	52	56	1976	28	1978	0.031	52	0.64	1968	0.00	52	0.0	2008	0.0	52	0.	2008
11	16	63	52	78	2008	45	1982	44	52	57	2006	30	1978	0.057	52	0.88	1972	0.00	52	0.0	2008	0.0	52	0.	2008
11	17	63	52	75	1977	46	1982	44	52	55	1983	24	1958	0.108	52	2.34	1996	0.00	52	0.0	2008	0.0	52	0.	2008
11	18	63	52	75	2005	53	1982	43	52	54	1965	29	1958	0.049	52	0.90	1982	0.00	52	0.0	2008	0.0	52	0.	2008
11	19	63	52	73	2005	52	1994	43	52	54	1996	26	1964	0.017	52	0.50	1982	0.00	52	0.0	2008	0.0	52	0.	2008
11	20	62	52	74	1989	51	1963	41	52	52	1966	27	1964	0.064	52	1.06	1963	0.00	52	0.0	2008	0.0	52	0.	2008
11	21	61	52	73	1989	51	1985	41	52	54	1986	27	1979	0.039	52	0.84	1978	0.00	52	0.0	2008	0.0	52	0.	2008
11	22	61	52	71	1962	51	1972	41	52	55	1996	28	1956	0.052	52	0.53	1977	0.00	52	0.0	2008	0.0	52	0.	2008
11	23	61	52	80	1959	48	1983	40	52	55	1998	29	1956	0.034	52	0.59	1988	0.00	52	0.0	2008	0.0	52	0.	2008
11	24	61	51	72	1986	49	1955	40	52	51	1981	31	1975	0.053	52	1.03	1985	0.00	52	0.0	2008	0.0	52	0.	2008
11	25	60	52	75	1959	46	2000	40	52	53	1986	30	1993	0.029	52	0.47	1983	0.00	52	0.0	2008	0.0	52	0.	2008
11	26	61	52	78	1995	49	2000	40	52	49	2008	30	1956	0.073	52	1.09	1997	0.00	52	0.0	2008	0.0	52	0.	2008
11	27	60	52	74	1957	46	1963	39	51	53	1995	30	1969	0.043	52	1.21	1970	0.00	52	0.0	2008	0.0	52	0.	2008
11	28	59	50	73	1958	47	2000	39	52	52	2008	30	1976	0.074	52	2.00	1970	0.00	52	0.0	2008	0.0	52	0.	2008
11	29	59	50	71	1977	49	2004	38	52	48	2003	28	1976	0.036	52	0.37	1966	0.00	52	0.0	2008	0.0	52	0.	2008
11	30	58	49	70	1995	48	1963	39	50	53	1966	29	1976	0.081	52	1.10	1982	0.00	52	0.0	2008	0.0	52	0.	2008
12	1	60	51	75	1977	44	1963	40	53	50	1995	28	1976	0.067	51	0.93	1973	0.00	52	0.0	2007	0.0	51	0.	2007
12	2	60	51	73	1995	44	1963	39	53	51	1966	28	1969	0.047	51	0.53	1985	0.00	52	0.0	2007	0.0	52	0.	2007
12	3	58	51	70	1958	43	1963	39	53	52	1987	28	1957	0.058	51	0.59	1974	0.00	52	0.0	2007	0.0	52	0.	2007
12	4	58	51	70	1958	40	1963	38	52	52	1995	29	1990	0.029	51	0.36	1967	0.00	52	0.0	2007	0.0	52	0.	2007
12	5	57	51	74	1958	40	1963	39	53	54	1995	25	1972	0.058	51	0.56	1987	0.00	52	0.0	2007	0.0	52	0.	2007
12	6	58	51	72	1979	40	1963	39	53	51	2003	29	1972	0.110	51	1.88	2007	0.00	52	0.0	2007	0.0	52	0.	2007
12	7	57	51	70	1989	42	1963	38	53	53	1995	28	1972	0.052	51	1.01	2004	0.00	52	0.0	2007	0.0	52	0.	2007
12	8	57	52	67	2006	41	1965	38	53	50	1970	26	1972	0.027	51	0.58	1997	0.00	52	0.0	2007	0.0	52	0.	2007
12	9	56	52	68	1988	40	1965	38	53	50	1993	20	1972	0.057	51	0.70	1955	0.00	52	0.0	2007	0.0	52	0.	2007
12	10	56	52	67	2006	44	1965	37	53	52	1996	19	1972	0.047	51	0.50	1999	0.00	52	0.0	2007	0.0	52	0.	2007
12	11	56	52	66	1987	43	1957	37	53	50	1995	18	1972	0.059	51	0.96	1990	0.00	52	0.0	2007	0.0	52	0.	2007
12	12	56	52	73	1958	41	1957	37	53	51	1995	18	1972	0.077	51	2.18	1995	0.00	52	0.0	2007	0.0	52	0.	2007
12	13	55	52	74	1958	40	1957	37	53	53	1996	22	1972	0.033	51	0.58	1995	0.00	52	0.0	2007	0.0	52	0.	2007
12	14	54	52	68	1988	42	1970	37	53	50	1983	23	1972	0.105	51	1.60	2002	0.00	52	0.0	2007	0.0	52	0.	2007
12	15	54	52	65	1983	38	1963	37	53	53	1983	23	1975	0.045	51	0.85	1957	0.00	52	0.0	2007	0.0	52	0.	2007

12	16	55	52	68	1976	39	1963	36	53	53	1962	22	1967	0.073	51	1.55	2002	0.00	52	0.0	2007	0.0	52	0.	2007
12	17	53	52	70	1958	38	1963	36	53	52	1962	24	1967	0.082	51	0.70	2005	0.00	52	0.0	2007	0.0	52	0.	2007
12	18	54	52	70	1958	36	1963	36	53	51	1962	24	1965	0.052	51	0.58	2005	0.00	52	0.0	2007	0.0	52	0.	2007
12	19	54	52	67	1999	38	1963	37	51	49	1955	27	1989	0.059	51	0.79	1955	0.00	52	0.0	2007	0.0	52	0.	2007
12	20	53	53	67	1999	38	1985	37	53	52	1955	23	1965	0.097	51	1.79	1969	0.00	52	0.0	2007	0.0	52	0.	2007
12	21	52	52	66	1969	34	1965	37	53	54	1969	21	1965	0.062	51	0.62	1996	0.00	52	0.0	2007	0.0	52	0.	2007
12	22	53	52	67	1999	35	1965	37	51	55	1964	20	1990	0.110	51	1.20	1982	0.00	52	0.0	2007	0.0	52	0.	2007
12	23	53	52	66	1964	36	1978	36	51	58	1955	20	1990	0.104	51	1.64	1955	0.00	52	0.0	2007	0.0	52	0.	2007
12	24	52	52	67	1964	38	1990	37	51	58	1964	25	1998	0.090	51	1.27	1979	0.00	52	0.0	2007	0.0	52	0.	2007
12	25	52	51	69	1964	38	1992	36	50	52	2005	22	1990	0.086	51	0.93	1971	0.00	51	0.0	2007	0.0	52	0.	2007
12	26	51	52	65	1967	35	1993	37	51	53	1964	24	1956	0.035	51	0.70	1955	0.00	52	0.0	2007	0.0	52	0.	2007
12	27	52	52	68	2006	35	1992	36	52	49	1983	24	1962	0.088	51	0.94	2004	0.00	52	0.0	2007	0.0	52	0.	2007
12	28	53	52	69	1967	37	1985	37	52	51	2005	24	1976	0.132	51	2.20	2005	0.00	52	0.0	2007	0.0	52	0.	2007
12	29	53	52	71	1967	40	1988	37	51	49	1977	24	1960	0.085	51	0.87	1965	0.00	52	0.0	2007	0.0	52	0.	2007
12	30	53	52	66	1967	41	1961	36	51	53	1996	24	1962	0.113	51	1.51	2005	0.00	52	0.0	2007	0.0	52	0.	2007
12	31	53	52	64	2007	39	1961	37	51	54	1996	21	1978	0.064	51	0.97	2004	0.00	52	0.0	2007	0.0	52	0.	2007

Western Regional Climate Center, wrcc@dri.edu

Table 5.1B-2 (5 Pages)
BAAQMD Historical Air Quality Data

San Francisco Bay Area Air Basin

Ozone Air Quality Trend

Ozone concentrations in the San Francisco Bay Area are much lower than in the South Coast and San Joaquin Valley Air Basins. The peak 1-hour and 8-hour indicators have declined by nearly 18 percent during the last 20 years. The number of days when State and national standards are exceeded show a similar trend. Although the long-term trends indicate improving air quality, since 2000 the peak indicators have been relatively flat. This may be attributable to changes in the mix and reactivity of precursor emissions in the San Francisco Bay. Continuing implementation of the aggressive emissions control measures will ensure continued progress throughout the Basin.

Meteorology can cause ozone and ozone precursor emissions to be transported from one air basin to another. The ARB has identified the San Francisco Bay Area Air Basin as a transport contributor to the following six areas: the Sacramento region, the Mountain Counties Air Basin, the North Central Coast Air Basin, the North Coast Air Basin, the San Joaquin Valley Air Basin, and the South Central Coast Air Basin. The amount of transport impact varies from day to day, depending in large part on meteorology. To the extent that the Bay Area continues to reduce ozone precursor emissions, the transport impact on downwind areas should also decrease.

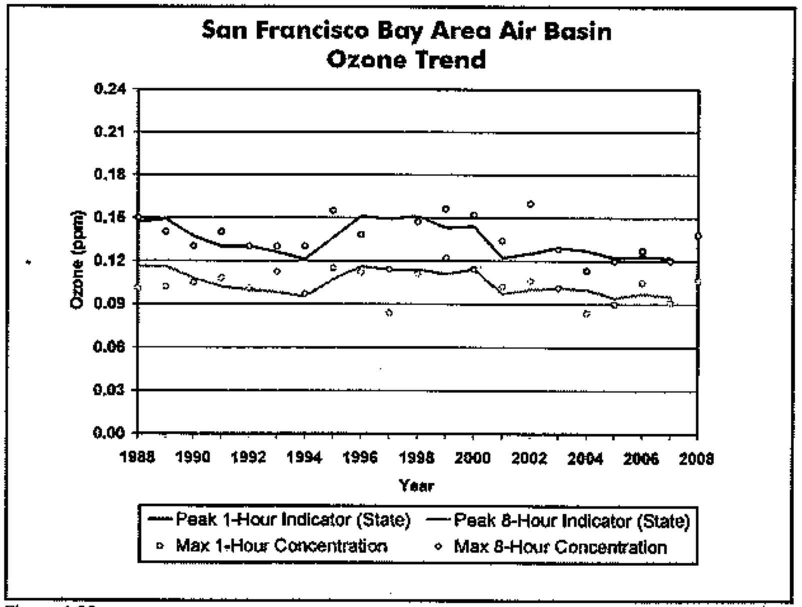


Figure 4-20

OZONE (ppm)	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008[1]
Avg. of 4th High 8-Hr. in 3 Yrs (Nat)	0.092	0.097	0.088	0.084	0.082	0.081	0.082	0.087	0.093	0.090	0.089	0.086	0.087	0.082	0.082	0.086	0.084	0.078	0.080	0.077	
4th High 1-Hr. in 3 Yrs[2]	0.140	0.140	0.130	0.130	0.130	0.120	0.121	0.138	0.138	0.138	0.138	0.139	0.139	0.126	0.124	0.123	0.123	0.113	0.118	0.120	
Maximum 1-Hr. Concentration	0.150	0.140	0.130	0.140	0.130	0.130	0.130	0.155	0.138	0.114	0.147	0.156	0.152	0.134	0.160	0.128	0.113	0.120	0.127	0.120	0.138
Days Above Nat. 8-Hr. Std.[3]	34	24	13	16	18	18	13	22	25	5	24	18	9	13	15	12	7	5	17	2	12

[1] Preliminary data for 2008 are shown here, however they are subject to change. 2007 is the last year for which complete and approved data is available, thus calculated annual statistics are not included for 2008.

[2] The national 1-Hour standard has been revoked. Historical 1-Hour data are provided for reference.

[3] The national 8-Hour standard has recently been lowered to .075. As a result, exceedance day numbers are higher than in previous years.

Table 4-18

San Francisco Bay Area Air Basin

Nitrogen Dioxide Air Quality Trend

The San Francisco Bay Area has attained both the State and national NO_2 standards for more than 20 years. During this time-period, there have been no concentrations that exceeded the level of the State 1-hour or the national annual standard. Ambient concentrations continue to be well below the level of both standards. The peak 1-hour indicator has declined by 56 percent in the San Francisco Bay Area since 1988. This downward trend is expected to continue.

NO_2 is formed from NO_x emissions, which also contribute to ozone. As a result, the majority of the future emission control measures will be implemented as part of the overall ozone control strategy. Many of these control measures will target mobile sources, which account for more than three-quarters of California's NO_x emissions.

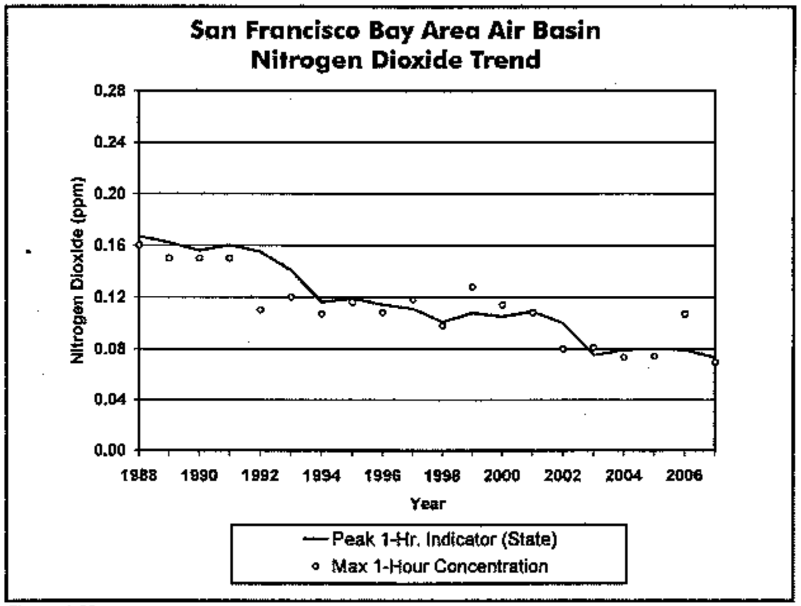


Figure 4-28

NITROGEN DIOXIDE (ppm)	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. 1-Hr. Concentration	0.160	0.150	0.150	0.150	0.110	0.120	0.107	0.116	0.108	0.118	0.098	0.128	0.114	0.108	0.080	0.081	0.073	0.074	0.107	0.069
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. Annual Average (State)	0.032	0.032	0.030	0.031	0.027	0.027	0.028	0.027	0.025	0.025	0.025	0.026	0.025	0.024	0.019	0.018	0.017	0.019	0.016	0.017

Table 4-26

San Francisco Bay Area Air Basin

Carbon Monoxide Air Quality Trend

Similar to other areas of the State, CO concentrations in the San Francisco Bay Area Air Basin have declined substantially over the last 20 years. The peak 8-hour indicator value during 2007 is 32 percent of what it was during 1988 and is now well below the level of the standards. In fact, neither the State nor the national standards have been exceeded in this area since 1991.

Much of the decline in ambient CO concentrations can be attributed to the introduction of clean fuels and newer, cleaner motor vehicles. The San Francisco Bay Area Air Basin is currently designated as attainment for both the State and national CO standards. Based on emission projections, the area is expected to maintain its attainment status in the coming years.

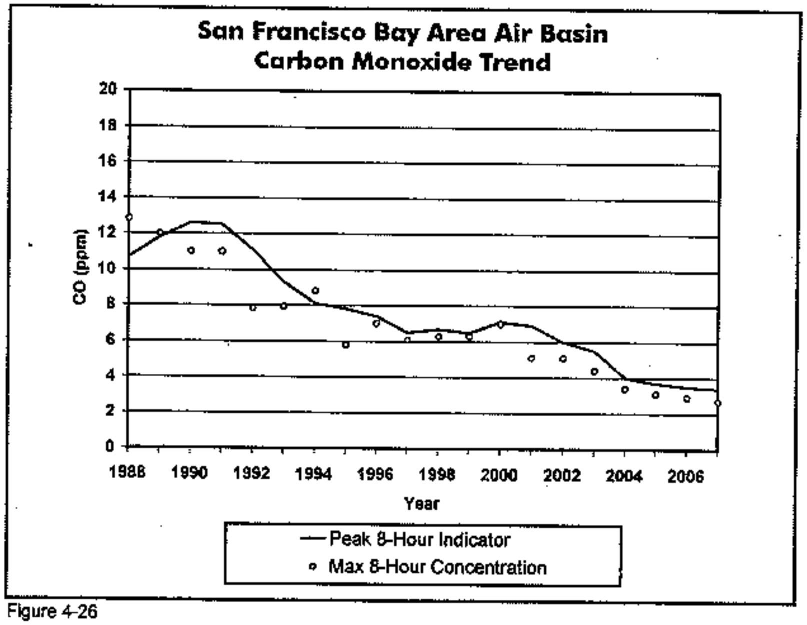


Figure 4-26

CARBON MONOXIDE (ppm)	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. 1-Hr. Concentration	15.0	19.0	18.0	15.0	12.0	14.0	12.0	10.1	8.8	10.7	8.7	9.0	9.8	7.6	7.7	8.6	4.8	4.5	5.5	5.5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Days Above State 8-Hr. Std.	4	10	4	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 4-24

San Francisco Bay Area Air Basin

PM_{10} Air Quality Trend

As with other pollutants, the PM_{10} statistics also show overall improvement. During the period for which data are available, the three-year average of the annual average (State) decreased by 23 percent.

Calculated exceedance days for the State 24-hour standard dropped from a high of 76 days during 1989 to 24 days during 2007. The national 24-hour standard was last exceeded in 1991. Because many of the same sources contribute to both ozone and PM_{10}, future ozone precursor emission controls should help ensure continued PM_{10} improvements.

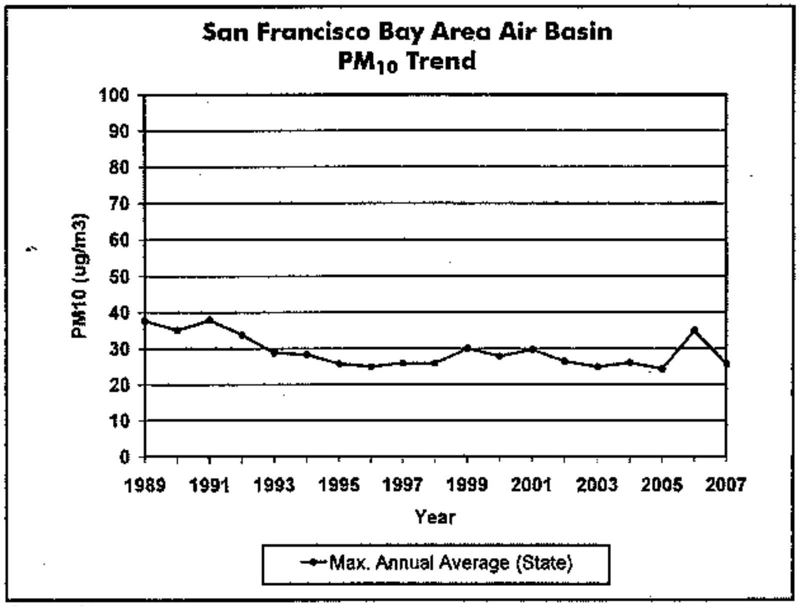


Figure 4-23

PM_{10} (µg/m³)	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. 24-Hr. Concentration (Nat)	146	150	165	155	112	101	97	75	77	95	92	119	76	109	80	58	63	78	104	73
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Max. Annual Average (Nat)	33.8	40.8	35.2	38.3	33.7	28.8	28.6	28.4	24.9	25.8	25.1	28.7	26.8	28.9	30.6	24.2	25.3	23.5	34.1	24.8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Calc Days Above Nat 24-Hr Std		0	6	3-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4-21

San Francisco Bay Area Air Basin

$PM_{2.5}$ Air Quality Trend

Annual average $PM_{2.5}$ concentrations (national) in the San Francisco Bay Area have decreased in the last nine years. The 98th percentile of 24-hour $PM_{2.5}$ concentrations also declined during the last nine-year period. The State annual average concentration trend however, remained relatively constant during the last eight years, due to differences in State and national monitoring methods. Similar to PM_{10}, year-to-year changes in meteorology can mask the impacts of emission control programs. Measures adopted as part of SB 656, as well as programs to reduce ozone and diesel PM will help in reducing public exposure to $PM_{2.5}$ in this region.

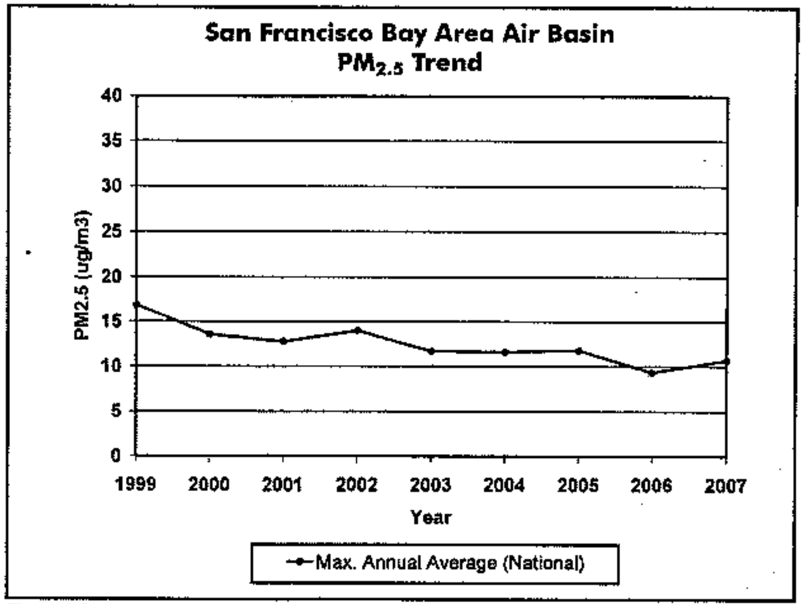


Figure 4-24

$PM_{2.5}$ (µg/m³)	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Max. 24-Hr. Concentration (Nat)												90.5	67.2	107.5	76.7	56.1	73.7	54.6	75.3	57.5
Annual Average (State)													11.6	12.9	14.0	11.7	12.7	11.8	12.4	13.3

Table 4-22

Table 5.1B-3 (8 pages)

BAY AREA AIR POLLUTION SUMMARY — 2005

—See NOTES on back of this page

MONITORING STATIONS	OZONE						CARBON MONOXIDE			NITROGEN DIOXIDE			SULFUR DIOXIDE			PM_{10}				$PM_{2.5}$				
	Max 1-Hr	Cal Days	Max 8-Hr	Nat Days	Cal Days	3-Yr Avg	Max 1-Hr	Max 8-Hr	Nat/Cal Days	Max 1-Hr	Ann Avg	Nat/Cal Days	Max 24-Hr	Ann Avg	Nat/Cal Days	Ann Avg	Max 24-Hr	Nat Days	Cal Days	Max 24-Hr	Nat Days	3-Yr Avg	Ann Avg	3-Yr Avg
North Counties	(ppb)		(ppb)				(ppm)			(ppb)			(ppb)			($\mu g/m^3$)				($\mu g/m^3$)			($\mu g/m^3$)	
Napa	91	0	67	0	0	61	3.2	2.0	0	60	10	0	-	-	-	18.0	40	0	0	-	-	-	-	-
San Rafael	81	0	59	0	0	51	3.0	1.7	0	54	13	0	-	-	-	16.5	39	0	0	-	-	-	-	-
Santa Rosa	72	0	51	0	0	49	2.5	2.0	0	47	11	0	-	-	-	15.9	39	0	0	33.6	0	28.2	7.6	8.2
Vallejo	90	0	70	0	0	60	3.9	3.1	0	70	11	0	5	1.2	0	17.3	52	0	1	43.8	0	32.5	9.7	10.0
Coast & Central Bay																								
Oakland*	68	0	45	0	0	39	3.4	2.4	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Richmond	-	-	-	-	-	-	-	-	-	-	-	-	6	1.1	0	-	-	-	-	-	-	-	-	-
San Francisco	58	0	54	0	0	48	2.5	2.1	0	66	16	0	7	1.4	0	20.1	46	0	0	43.6	0	32.6	9.5	9.9
San Pablo	66	0	57	0	0	52	2.8	1.3	0	54	12	0	6	1.7	0	19.0	42	0	0	-	-	-	-	-
Eastern District																								
Bethel Island	89	0	77	0	2	72	1.1	0.9	0	38	7	0	6	2.0	0	18.5	64	0	1	-	-	-	-	-
Concord	98	1	80	0	2	73	2.2	1.5	0	55	12	0	7	1.0	0	16.4	42	0	0	48.9	0	35.1	9.0	9.8
Crockett*	-	-	-	-	-	-	-	-	-	-	-	-	*	*	0	-	-	-	-	-	-	-	-	-
Fairfield	90	0	73	0	2	68	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livermore	120	6	90	1	7	78	3.4	1.8	0	72	14	0	-	-	-	18.8	49	0	0	32.1	0	29.4	9.0	9.4
Martinez	-	-	-	-	-		-	-	-	-	-	-	7	1.7	0	-	-	-	-	-	-	-	-	-
Pittsburg	94	0	78	0	2	69	3.3	1.7	0	58	11	0	9	2.4	0	20.1	57	0	1	-	-	-	-	-
South Central Bay																								
Fremont	105	1	78	0	1	60	3.2	2.0	0	69	15	0	-	-	-	17.8	54	0	1	33.4	0	27.6	9.0	9.0
Hayward*	*	*	*	*	*	*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redwood City	84	0	61	0	0	57	4.5	2.3	0	62	15	0	-	-	-	20.9	81	0	2	30.9	0	27.8	8.8	9.0
San Leandro	99	1	61	0	0	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Santa Clara Valley																								
Gilroy	87	0	67	0	0	71	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Los Gatos	110	3	87	1	3	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose Central	113	1	80	0	1	61	4.3	3.1	0	74	19	0	-	-	-	22.3	54	0	2	54.6	0	39.0	11.8	11.7
San Jose East*	110	1	83	0	1	59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose, Tully Road	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.2	71	0	4	50.6	0	35.9	10.5	10.3
San Martin	108	2	77	0	3	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sunnyvale	97	1	73	0	1	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Bay Area Days over Standard		9		1	9				0			0			0			0	6		0			

*See notes of explanation on back of this page

2005 NOTES

The annual Bay Area Air Pollution Summary summarizes measurements for the national and California pollutant standards. Note that measurements given in parts per hundred million (pphm) in prior years are now given in parts per billion (ppb).

*Station Information (see asterisks on front page)

The Hayward station was inoperative until July 19, 2005, due to construction on site.

The Crockett station was inoperative after March 27, 2005 due to construction on site.

The Oakland and San Jose East stations were closed on November 30, 2005.

Due to roof damage at the Concord station during the fourth quarter of 2004, the $PM_{2.5}$ sampler could not be operated on some of the required sampling days. The $PM_{2.5}$ annual average and three-year average $PM_{2.5}$ statistics are based on available data.

Explanation of Terms

State and national excesses occur when pollutant concentrations surpass the indicated standards. For comparison, values in ppb must be converted to ppm and rounded to the same number of decimal places as the original standard.

MAX HR / MAX 8-HR / MAX 24-HR
The highest average contaminant concentration over a one-hour period, an eight-hour period (on any given day), or a 24-hour period (from midnight to midnight).

ANN AVG
The yearly average (arithmetic mean) of the readings taken at a given monitoring station.

NAT DAYS
The number of days during the year for which the monitoring station recorded contaminant concentrations in excess of the national standard.

CAL DAYS
The number of days during the year for which the station recorded contaminant levels in excess of the California standard.

TOTAL BAY AREA DAYS OVER STANDARD is not a sum of excesses at individual stations, but rather a sum of the number of days for which excesses occurred at any one or more stations.

3-YR AVG (8-hr ozone standard)
The 3-year average of the fourth highest 8-hour average ozone concentration for each monitoring station. *A 3-year average greater than 84 ppb at any monitoring station means that the region will be considered out of attainment by the EPA.*

PM_{10}
Particulate matter ten microns or smaller in size. (PM_{10} is only sampled every sixth day. *Actual days over standard can be estimated to be six times the number shown.*)

$PM_{2.5}$
Particulate matter 2.5 microns or smaller in size. $PM_{2.5}$ is a sub-category of PM_{10}.

PM_{10} ANN AVG and MAX 24-HR
California PM_{10} Annual Average and Maximum 24-Hour concentrations are reported at local temperature and pressure conditions. National PM_{10} Annual Average and Maximum 24-Hour concentrations are reported at standard temperature and pressure conditions. This table shows the California readings for PM_{10} Ann Avg and Max 24-Hr, which are generally slightly higher than the national readings.

3-YR AVG ($PM_{2.5}$ 24-hour standard)
The 3-year average of the annual 98th percentiles of the individual 24-hour concentrations of $PM_{2.5}$. *A 3-year average greater than 65 µg/m^3 at any monitoring station means that the region will be considered out of attainment by the EPA.*

3-YR AVG ($PM_{2.5}$ annual standard)
The 3-year average of the quarterly averages of $PM_{2.5}$. *A 3-year average greater than 15 µg/m^3 at any monitoring station means that the region will be considered out of attainment by the EPA.*

HEALTH-BASED AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California Std	National Std
Ozone	1 Hour[1]	0.09 ppm	
	8 Hour[2]	0.070 ppm	0.08 ppm
Carbon Monoxide	1 Hour	20 ppm	35 ppm
	8 Hour	9.0 ppm	9 ppm
Nitrogen Dioxide	1 Hour	0.25 ppm	—
	Annual	—	0.053 ppm
Sulfur Dioxide	24 Hour	0.04 ppm	0.14 ppm
	Annual	—	0.03 ppm
Particulates < 10 microns –	24 Hour	50 µg/m3	150 µg/m3
	Annual	20 µg/m3	50 µg/m3
Particulates < 2.5 microns –	24 Hour	—	65 µg/m3
	Annual	12 µg/m3	15 µg/m3

[1]The U.S. EPA revoked the national 1-hour ozone standard on June 15, 2005.
[2]The California 8-hour ozone standard was implemented on May 17, 2005.

Concentrations	ppm	ppb	µg/m3
	parts per million	parts per billion	micrograms per cubic meter

TEN-YEAR BAY AREA AIR QUALITY SUMMARY

DAYS OVER STANDARDS

YEAR	OZONE			CARBON MONOXIDE				Nitrogen Dioxide	Sulfur Dioxide		PM_{10}		$PM_{2.5}$
	8-Hr	1-Hr	8-Hr	1-Hr		8-Hr		1-Hr	24-Hr		24-Hr*		24-Hr**
	Nat	Cal	Cal	Nat	Cal	Nat	Cal	Cal	Nat	Cal	Nat	Cal	Nat
1996	-	34	-	0	0	0	0	0	0	0	0	3	-
1997	-	8	-	0	0	0	0	0	0	0	0	4	-
1998	16	29	-	0	0	0	0	0	0	0	0	5	-
1999	9	20	-	0	0	0	0	0	0	0	0	12	-
2000	4	12	-	0	0	0	0	0	0	0	0	7	1
2001	7	15	-	0	0	0	0	0	0	0	0	10	5
2002	7	16	-	0	0	0	0	0	0	0	0	6	7
2003	7	19	-	0	0	0	0	0	0	0	0	6	0
2004	0	7	-	0	0	0	0	0	0	0	0	7	1
2005	1	9	9	0	0	0	0	0	0	0	0	6	0

*PM_{10} is sampled every sixth day—*actual* days over standard can be estimated to be six times the numbers listed.

**2000 was the first complete year of $PM_{2.5}$ data.

BAY AREA AIR POLLUTION SUMMARY — 2006

—See NOTES on second page

MONITORING STATIONS	OZONE						CARBON MONOXIDE			NITROGEN DIOXIDE			SULFUR DIOXIDE			PM_{10}				$PM_{2.5}$				
	Max 1-Hr	Cal Days	Max 8-Hr	Nat Days	Cal Days	3-Yr Avg	Max 1-Hr	Max 8-Hr	Nat/Cal Days	Max 1-Hr	Ann Avg	Nat/Cal Days	Max 24-Hr	Ann Avg	Nat/Cal Days	Ann Avg	Max 24-Hr	Nat Days	Cal Days	Max 24-Hr	Nat Days	3-Yr Avg	Ann Avg	3-Yr Avg
North Counties	(ppb)		(ppb)				(ppm)			(ppb)			(ppb)			($\mu g/m^3$)				($\mu g/m^3$)			($\mu g/m^3$)	
Napa	96	1	72	0	2	60	3.5	2.8	0	55	11	0	-	-	-	21.9	52	0	1	-	-	-	-	-
San Rafael	89	0	58	0	0	50	2.6	1.5	0	54	14	0	-	-	-	18.1	68	0	1	-	-	-	-	-
Santa Rosa	77	0	58	0	0	47	2.4	1.7	0	44	11	0	-	-	-	18.8	90	0	2	59.0	1	28.7	9.2	8.3
Vallejo	80	0	69	0	0	57	3.7	2.9	0	55	12	0	4	1.0	0	19.8	50	0	0	42.2	2	35.6	9.8	10.2
Coast & Central Bay																								
Richmond	-	-	-	-	-	-	-	-	-	-	-	-	6	1.6	0	-	-	-	-	-	-	-	-	-
San Francisco	53	0	46	0	0	45	2.7	2.1	0	107	16	0	6	1.3	0	22.9	61	0	3	54.3	3	30.9	9.7	9.7
San Pablo	61	0	50	0	0	48	2.5	1.4	0	55	13	0	5	1.6	0	21.3	62	0	2	-	-	-	-	-
Eastern District																								
Bethel Island	116	9	90	1	14	73	1.3	1.0	0	44	8	0	7	2.1	0	19.4	84	0	1	-	-	-	-	-
Concord	117	8	92	4	14	74	1.7	1.3	0	47	11	0	7	0.8	0	18.5	81	0	3	62.1	5	35.0	9.3	9.7
Crockett*	-	-	-	-	-	-	-	-	-	-	-	-	8*	1.8*	0*	-	-	-	-	-	-	-	-	-
Fairfield	106	3	87	1	8	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livermore	127	13	101	5	15	80	3.3	1.8	0	64	14	0	-	-	-	21.8	69	0	3	50.8	3	33.5	9.8	9.7
Martinez	-	-	-	-	-		-	-	-	-	-	-	7	1.9	0	-	-	-	-	-	-	-	-	-
Pittsburg	105	3	93	1	10	70	3.3	1.9	0	52	11	0	9	2.4	0	19.9	59	0	2	-	-	-	-	-
South Central Bay																								
Fremont	102	4	74	0	3	60	2.9	1.8	0	63	15	0	-	-	-	20.0	57	0	1	43.9	2	30.3	10.3	9.6
Hayward*	101	2	71	0	1	*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redwood City	85	0	63	0	0	53	5.5	2.4	0	69	14	0	-	-	-	19.8	70	0	2	75.3	1	29.4	9.6	9.2
San Leandro	88	0	66	0	0	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Santa Clara Valley																								
Gilroy	120	4	101	2	8	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Los Gatos	116	7	87	4	11	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose Central	118	5	87	1	5	63	4.1	2.9	0	74	18	0	-	-	-	21.0	73	0	2	64.4	6	38.5	10.8	11.4
San Jose, Tully Road*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0*	106*	0	13*	30.6*	0*	*	*	*
San Martin	123	7	105	5	11	76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sunnyvale	106	3	78	0	1	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Bay Area Days over Standard		18		12	22				0			0			0			0	15		10			

*See NOTES on second page

2006 NOTES

The annual Bay Area Air Pollution Summary summarizes measurements for the national and California pollutant standards.

*Station Information (see asterisks on front page)

Crockett was closed from March 27, 2005 to March 3, 2006 due to construction on site.

Hayward was closed part of 2005 due to construction on site. There was insufficient data for calculating three-year average ozone statistics.

San Jose-Tully $PM_{2.5}$ monitoring was discontinued on September 30, 2006 in preparation for moving the monitor to Gilroy in 2007, so there was insufficient data for calculating annual and three-year average $PM_{2.5}$ statistics. There was also construction activity near the site, which the Air District believes affected PM_{10} measurements.

Explanation of Terms

State and national excesses occur when pollutant concentrations surpass the indicated standards. For comparison, values in ppb must be converted to ppm and rounded to the same number of decimal places as the original standard.

MAX HR / MAX 8-HR / MAX 24-HR
The highest average contaminant concentration over a one-hour period, an eight-hour period (on any given day), or a 24-hour period (from midnight to midnight).

ANN AVG
The yearly average (arithmetic mean) of the readings taken at a given monitoring station.

NAT DAYS
The number of days during the year for which the monitoring station recorded contaminant concentrations in excess of the national standard.

CAL DAYS
The number of days during the year for which the station recorded contaminant levels in excess of the California standard.

TOTAL BAY AREA DAYS OVER STANDARD is not a sum of excesses at individual stations, but rather a sum of the number of days for which excesses occurred at any one or more stations.

3-YR AVG (Nat. 8-hr ozone standard)
The 3-year average of the fourth highest 8-hour average ozone concentration for each monitoring station. *A 3-year average greater than 84 ppb at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

PM_{10}
Particulate matter ten microns or smaller in size. (PM_{10} is only sampled every sixth day. *Actual* days over standard can be estimated to be six times the number shown.)

$PM_{2.5}$
Particulate matter 2.5 microns or smaller in size. $PM_{2.5}$ is a sub-category of PM_{10}.

PM_{10} ANN AVG and MAX 24-HR
This table shows PM_{10} data reported at local temperature and pressure conditions, according to the California standards. National PM_{10} data is converted to standard temperature and pressure conditions, which generally results in slightly lower readings.

3-YR AVG ($PM_{2.5}$ 24-hour standard)
The 3-year average of the annual 98th percentiles of the individual 24-hour concentrations of $PM_{2.5}$. *A 3-year average greater than 35 µg/m^3 at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

3-YR AVG ($PM_{2.5}$ annual standard)
The 3-year average of the quarterly averages of $PM_{2.5}$. *A 3-year average greater than 15 µg/m^3 at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

HEALTH-BASED AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California Std	National Std
Ozone	1 Hour 8 Hour	0.09 ppm 0.070 ppm	— 0.08 ppm
Carbon Monoxide	1 Hour 8 Hour	20 ppm 9.0 ppm	35 ppm 9 ppm
Nitrogen Dioxide	1 Hour Annual	0.25 ppm —	— 0.053 ppm
Sulfur Dioxide	24 Hour Annual	0.04 ppm —	0.14 ppm 0.03 ppm
Particulates ≤ 10 microns	24 Hour Annual[1]	50 µg/m^3 20 µg/m^3	150 µg/m^3 —
Particulates ≤ 2.5 microns	24 Hour[1] Annual	— 12 µg/m^3	35 µg/m^3 15 µg/m^3

[1] On Dec. 17, 2006, the U.S. EPA implemented a more stringent national 24-hour $PM_{2.5}$ standard—revising it from 65 µg/m^3 to 35 µg/m^3—and revoked the national annual average PM_{10} standard. $PM_{2.5}$ exceedance days for 2006 reflect the new standard.

Concentrations	ppm	ppb	µg/m3
	parts per million	parts per billion	micrograms per cubic meter

TEN-YEAR BAY AREA AIR QUALITY SUMMARY

DAYS OVER STANDARDS

YEAR	OZONE			CARBON MONOXIDE				Nitrogen Dioxide	Sulfur Dioxide		PM_{10}		$PM_{2.5}$
	8-Hr	1-Hr	8-Hr	1-Hr		8-Hr		1-Hr	24-Hr		24-Hr*		24-Hr**
	Nat	Cal		Nat	Cal	Nat	Cal	Cal	Nat	Cal	Nat	Cal	Nat
1997	-	8	-	0	0	0	0	0	0	0	0	4	-
1998	16	29	-	0	0	0	0	0	0	0	0	5	-
1999	9	20	-	0	0	0	0	0	0	0	0	12	-
2000	4	12	-	0	0	0	0	0	0	0	0	7	1
2001	7	15	-	0	0	0	0	0	0	0	0	10	5
2002	7	16	-	0	0	0	0	0	0	0	0	6	7
2003	7	19	-	0	0	0	0	0	0	0	0	6	0
2004	0	7	-	0	0	0	0	0	0	0	0	7	1
2005	1	9	9	0	0	0	0	0	0	0	0	6	0
2006	12	18	22	0	0	0	0	0	0	0	0	15	10

*PM_{10} is sampled every sixth day—*actual* days over standard can be estimated to be six times the numbers listed.

**2000 was the first complete year of $PM_{2.5}$ data.

BAY AREA AIR POLLUTION SUMMARY — 2007

—See NOTES on second page

MONITORING STATIONS	OZONE						CARBON MONOXIDE			NITROGEN DIOXIDE			SULFUR DIOXIDE			PM$_{10}$				PM$_{2.5}$				
	Max 1-Hr	Cal 1-Hr Days	Max 8-Hr	Nat 8-Hr Days	Cal Days	3-Yr Avg	Max 1-Hr	Max 8-Hr	Nat/Cal Days	Max 1-Hr	Ann Avg	Nat/Cal Days	Max 24-Hr	Ann Avg	Nat/Cal Days	Ann Avg	Max 24-Hr	Nat Days	Cal Days	Max 24-Hr	Nat Days	3-Yr Avg	Ann Avg	3-Yr Avg
North Counties	(ppb)		(ppb)				(ppm)			(ppb)			(ppb)			(µg/m³)				(µg/m³)			(µg/m³)	
Napa	74	0	61	0	0	57	3.2	2.0	0	53	10	0	-	-	-	21.4	50	0	0	-	-	-	-	-
San Rafael	72	0	57	0	0	48	2.8	1.3	0	57	14	0	-	-	-	17.5	56	0	1	-	-	-	-	-
Santa Rosa	71	0	59	0	0	47	2.6	1.7	0	46	11	0	-	-	-	17.1	37	0	0	32.0	0	30.4	7.6	8.1
Vallejo	78	0	66	0	0	54	3.3	2.7	0	58	11	0	4	1.3	0	19.0	52	0	2	40.8	4	36.2	9.8	9.8
Coast & Central Bay																								
Richmond	-	-	-	-	-	-	-	-	-	-	-	-	7	1.6	0	-	-	-	-	-	-	-	-	-
San Francisco	60	0	49	0	0	45	2.5	1.6	0	69	16	0	6	1.5	0	21.9	70	0	2	45.2	5	29.3	8.7	9.3
San Pablo	74	0	51	0	0	47	2.4	1.2	0	52	12	0	5	1.6	0	20.6	57	0	2	-	-	-	-	-
Eastern District																								
Benicia*	83	0	71	0	1	*	1.1	0.6	0	39	*	0	7	*	0	*	31	0	0					
Bethel Island	93	0	78	0	4	73	1.1	0.8	0	48	8	0	5	1.5	0	18.8	49	0	0	-	-	-	-	-
Concord	105	1	81	0	4	73	2.2	1.4	0	49	11	0	5	1.3	0	16.8	52	0	2	46.2	7	34.0	8.4	8.9
Crockett	-	-	-	-	-	-	-	-	-	-	-	-	9	2.0	0	-	-	-	-	-	-	-	-	-
Fairfield	89	0	67	0	0	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livermore	120	2	91	1	3	77	3.3	1.8	0	52	13	0	-	-	-	19.8	75	0	2	54.9	3	34.8	9.0	9.3
Martinez	-	-	-	-	-		-	-	-	-	-	-	8	1.7	0	-	-	-	-	-	-	-	-	-
Pittsburg	100	1	74	0	2	70	2.8	1.5	0	51	10	0	7	2.2	0	19.4	59	0	4	-	-	-	-	-
South Central Bay																								
Fremont	79	0	68	0	0	58	2.5	1.6	0	58	14	0	-	-	-	19.6	61	0	1	51.2	2	30.4	8.7	9.4
Hayward*	75	0	65	0	0	*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redwood City	77	0	69	0	0	51	5.5	2.3	0	57	13	0	-	-	-	19.6	56	0	1	45.4	1	31.0	8.3	8.9
San Leandro	71	0	54	0	0	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Santa Clara Valley																								
Gilroy*	91	0	70	0	0	70	-	-	-	-	-	-	-	-	-	-	-	-	-	21.5	0	*	*	*
Los Gatos	84	0	65	0	0	68	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose Central	83	0	68	0	0	61	3.5	2.7	0	65	17	0	-	-	-	22.0	69	0	3	57.5	9	38.3	10.7	11.1
San Jose, Tully Road*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25.6	78	0	3	-	-	-	-	-
San Martin	96	1	73	0	4	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sunnyvale	77	0	68	0	0	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Bay Area Days over Standard		**4**		**1**	**9**				**0**			**0**			**0**			**0**	**4**		**14**			

*See NOTES on second page

2007 NOTES

The annual Bay Area Air Pollution Summary summarizes measurements for the national and California pollutant standards.

*Station Information (see asterisks on front page)

$PM_{2.5}$ monitoring began at Gilroy on March 1, 2007. Since there are only 3 complete quarters of data for 2007, annual statistics are not provided for $PM_{2.5}$.

The Benicia site was opened on April 1, 2007. Since there are only 3 quarters of data for 2007, annual statistics are not provided for this site.

The San Jose-Tully site was closed on December 31, 2007.

The Hayward station was closed part of 2005 due to construction on site. Therefore, three-year average ozone statistics are not available

An Oakland site was opened on November 1, 2007, and a Berkeley site was opened on December 13, 2007. Since there is only a brief period of data available for these sites in 2007, summary reporting will not begin until 2008.

Explanation of Terms

State and national excesses occur when pollutant concentrations surpass the indicated standards. For comparison, values in ppb must be converted to ppm and rounded to the same number of decimal places as the original standard.

MAX HR / MAX 8-HR / MAX 24-HR
The highest average contaminant concentration over a one-hour period, an eight-hour period (on any given day), or a 24-hour period (from midnight to midnight).

ANN AVG
The yearly average (arithmetic mean) of the readings taken at a given monitoring station.

NAT DAYS
The number of days during the year for which the monitoring station recorded contaminant concentrations in excess of the national standard.

CAL DAYS
The number of days during the year for which the station recorded contaminant levels in excess of the California standard.

TOTAL BAY AREA DAYS OVER STANDARD is not a sum of excesses at individual stations, but rather a sum of the number of days for which excesses occurred at any one or more stations.

3-YR AVG (Nat. 8-hr ozone standard)
The 3-year average of the fourth highest 8-hour average ozone concentration for each monitoring station. *A 3-year average greater than 84 ppb at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

PM_{10}
Particulate matter ten microns or smaller in size. (PM_{10} is only sampled every sixth day. *Actual* days over standard can be estimated to be six times the number shown.)

$PM_{2.5}$
Particulate matter 2.5 microns or smaller in size. $PM_{2.5}$ is a sub-category of PM_{10}.

PM_{10} ANN AVG and MAX 24-HR
This table shows PM_{10} data reported at local temperature and pressure conditions, according to the California standards. National PM_{10} data is converted to standard temperature and pressure conditions, which generally results in slightly lower readings.

3-YR AVG ($PM_{2.5}$ 24-hour standard)
The 3-year average of the annual 98th percentiles of the individual 24-hour concentrations of $PM_{2.5}$. *A 3-year average greater than 35 $\mu g/m^3$ at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

3-YR AVG ($PM_{2.5}$ annual standard)
The 3-year average of the quarterly averages of $PM_{2.5}$. *A 3-year average greater than 15 $\mu g/m^3$ at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.*

HEALTH-BASED AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California Std	National Std
Ozone	1 Hour 8 Hour	0.09 ppm 0.070 ppm	— 0.08 ppm*
Carbon Monoxide	1 Hour 8 Hour	20 ppm 9.0 ppm	35 ppm 9 ppm
Nitrogen Dioxide	1 Hour Annual	0.25 ppm —	— 0.053 ppm
Sulfur Dioxide	24 Hour Annual	0.04 ppm —	0.14 ppm 0.03 ppm
Particulates ≤ 10 microns	24 Hour Annual[1]	50 $\mu g/m^3$ 20 $\mu g/m^3$	150 $\mu g/m^3$ —
Particulates ≤ 2.5 microns	24 Hour[1] Annual	— 12 $\mu g/m^3$	35 $\mu g/m^3$ 15 $\mu g/m^3$

[1] On May. 17, 2008, the U.S. EPA implemented a more stringent national 8-hour ozone standard of 0.075 ppm. Ozone exceedance days in this 2007 Summary reflect the 0.08 ppm standard that was then in place.

Concentrations	**ppm**	**ppb**	**$\mu g/m^3$**
	parts per million	parts per billion	micrograms per cubic meter

TEN-YEAR BAY AREA AIR QUALITY SUMMARY

DAYS OVER STANDARDS

YEAR	OZONE			CARBON MONOXIDE				Nitrogen Dioxide	Sulfur Dioxide		PM_{10}		$PM_{2.5}$
	8-Hr	1-Hr	8-Hr	1-Hr		8-Hr		1-Hr	24-Hr		24-Hr*		24-Hr**
	Nat	Cal		Nat	Cal	Nat	Cal	Cal	Nat	Cal	Nat	Cal	Nat
1998	16	29	-	0	0	0	0	0	0	0	0	5	-
1999	9	20	-	0	0	0	0	0	0	0	0	12	-
2000	4	12	-	0	0	0	0	0	0	0	0	7	1
2001	7	15	-	0	0	0	0	0	0	0	0	10	5
2002	7	16	-	0	0	0	0	0	0	0	0	6	7
2003	7	19	-	0	0	0	0	0	0	0	0	6	0
2004	0	7	-	0	0	0	0	0	0	0	0	7	1
2005	1	9	9	0	0	0	0	0	0	0	0	6	0
2006	12	18	22	0	0	0	0	0	0	0	0	15	10
2007	1	4	9	0	0	0	0	0	0	0	0	4	14

*PM_{10} is sampled every sixth day—*actual* days over standard can be estimated to be six times the numbers listed.

**On Dec. 17, 2006, the U.S. EPA implemented a more stringent national 24-hour $PM_{2.5}$ standard—revising it from 65 $\mu g/m^3$ to 35 $\mu g/m^3$. $PM_{2.5}$ exceedance days for 2006 and 2007 reflect the new standard.

BAY AREA AIR POLLUTION SUMMARY — 2008

—See NOTES on second page

MONITORING STATIONS	OZONE						CARBON MONOXIDE			NITROGEN DIOXIDE			SULFUR DIOXIDE			PM_{10}				$PM_{2.5}$				
	Max 1-Hr	Cal 1-Hr Days	Max 8-Hr	Nat 8-Hr Days	Cal Days	3-Yr Avg	Max 1-Hr	Max 8-Hr	Nat/Cal Days	Max 1-Hr	Ann Avg	Nat/Cal Days	Max 24-Hr	Ann Avg	Nat/Cal Days	Ann Avg	Max 24-Hr	Nat Days	Cal Days	Max 24-Hr	Nat Days	3-Yr Avg	Ann Avg	3-Yr Avg
North Counties	(ppb)		(ppb)				(ppm)			(ppb)			(ppb)			(μg/m^3)				(μg/m^3)			(μg/m^3)	
Napa	107	1	77	2	2	61	3.2	1.8	0	64	10	0	-	-	-	21.6	50	0	0	-	-	-	-	-
San Rafael	85	0	69	0	0	50	1.8	1.1	0	56	13	0	-	-	-	18.6	41	0	0	-	-	-	-	-
Santa Rosa*	76	0	64	0	0	51	3.5	1.5	0	49	11	0	-	-	-	*	*	*	*	30.8	0	30.4	8.6	8.4
Vallejo*	109	1	75	0	3	60	2.7	2.3	0	67	10	0	4	1.2	0	*	*	*	*	50.0	7	36.4	9.9	9.8
Coast & Central Bay																								
Berkeley*	53	0	49	0	0	*	2.8	1.7	0	55	14	0	4	1.3	0	22.5	44	0	0	-	-	-	-	-
Oakland*	86	0	64	0	0	*	3.0	1.6	0	70	15	0	-	-	-	-	-	-	-	30.1	0	*	9.5	*
Richmond	-	-	-	-	-	-	-	-	-	-	-	-	8	1.5	0	-	-	-	-	-	-	-	-	-
San Francisco	82	0	66	0	0	46	5.7	2.3	0	62	16	0	5	1.5	0	22.0	41	0	0	29.4	0	26.3	9.8	9.4
San Pablo	84	0	63	0	0	50	2.5	1.3	0	67	12	0	4	1.4	0	20.9	44	0	0	-	-	-	-	-
Eastern District																								
Benicia*	123	2	86	3	7	*	1.0	0.8	0	38	7	0	5	1.6	0	18.1	52	0	1	-	-	-	-	-
Bethel Island	109	4	90	4	10	76	1.5	1.1	0	41	7	0	4	1.4	0	24.1	77	0	3	-	-	-	-	-
Concord	119	3	88	6	8	78	1.6	1.1	0	50	10	0	4	1.2	0	17.5	51	0	1	60.3	3	34.6	9.3	9.0
Crockett	-	-	-	-	-	-	-	-	-	-	-	-	13	2.1	0	-	-	-	-	-	-	-	-	-
Fairfield	116	2	90	1	2	68	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livermore*	141	5	110	6	8	81	2.4	1.4	0	58	13	0	-	-	-	*	*	*	*	38.6	2	36.2	10.1	9.6
Martinez	-	-	-	-	-		-	-	-	-	-	-	6	1.7	0	-	-	-	-	-	-	-	-	-
Pittsburg*	106	1	83	1	2	71	2.8	1.4	0	56	10	0	6	1.8	0	*	*	*	*	-	-	-	-	-
South Central Bay																								
Fremont*	112	1	78	1	3	61	1.9	1.4	0	62	14	0	-	-	-	*	*	*	*	28.6	0	28.8	9.4	9.5
Hayward	114	1	86	1	3	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redwood City*	82	0	69	0	0	53	4.3	1.9	0	69	14	0	-	-	-	*	*	*	*	27.9	0	29.3	9.1	9.0
San Leandro	96	1	68	0	0	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Santa Clara Valley																								
Gilroy*	103	1	79	1	4	73	-	-	-	-	-	-	-	-	-	-	-	-	-	25.5	0	*	8.7	*
Los Gatos	122	2	97	2	6	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose Central	118	1	80	2	3	65	3.3	2.5	0	80	17	0	-	-	-	23.4	57	0	1	41.9	5	35.8	11.5	11.0
San Martin	123	2	77	2	5	76	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sunnyvale	93	0	76	1	2	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Bay Area Days over Standard		9		12	20				0			0			0			0	5		12			

*See NOTES on second page

2008 NOTES

The annual Bay Area Air Pollution Summary summarizes pollutant concentrations for comparison to the national and California air pollution standards.

*Station Information (see asterisks on front page)

$PM_{2.5}$ monitoring began at Gilroy on March 1, 2007. Therefore, three-year average $PM_{2.5}$ statistics are not available.

The Benicia site opened on April 1, 2007 and the Berkeley site opened on December 13, 2007. Therefore, three-year average ozone statistics are not available.

The Oakland site opened on November 1, 2007. Therefore, three-year average statistics for ozone and $PM_{2.5}$ are not available.

PM_{10} monitoring was discontinued on June 30, 2008 at Fremont, Livermore, Pittsburg, Redwood City, Santa Rosa, and Vallejo. Therefore PM_{10} statistics are no longer available at these sites.

The San Leandro and Sunnyvale sites were closed on November 30, 2008.

SO_2 monitoring was discontinued at San Francisco on December 31, 2008.

The Benicia and Pittsburg sites were closed on December 31, 2008.

Explanation of Terms

State and national excesses occur when pollutant concentrations surpass the indicated standards. For comparison, values in ppb must be converted to ppm and rounded to the same number of decimal places as the original standard.

MAX HR / MAX 8-HR / MAX 24-HR
The highest average contaminant concentration over a one-hour period, an eight-hour period (on any given day), or a 24-hour period (from midnight to midnight).

ANN AVG
The yearly average (arithmetic mean) of the readings taken at a given monitoring station.

NAT DAYS
The number of days during the year for which the monitoring station recorded contaminant concentrations in excess of the national standard.

CAL DAYS
The number of days during the year for which the station recorded contaminant concentrations in excess of the California standard.

TOTAL BAY AREA DAYS OVER STANDARD
is not a sum of excesses at individual stations, but rather a sum of the number of days for which excesses occurred at any one or more stations.

3-YR AVG (Nat. 8-hr ozone standard)
The 3-year average of the fourth highest 8-hour average ozone concentration for each monitoring station. A 3-year average greater than 84 ppb at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.

PM_{10}
Particulate matter ten microns or smaller in size. PM_{10} is only sampled every sixth day. Actual days over standard can be estimated to be six times the number shown.

$PM_{2.5}$
Particulate matter 2.5 microns or smaller in size. $PM_{2.5}$ is a sub-category of PM_{10}.

PM_{10} ANN AVG and MAX 24-HR
This table shows PM_{10} data reported at local temperature and pressure conditions, according to the California standards. National PM_{10} data are converted to standard temperature and pressure conditions, which generally results in slightly lower readings.

3-YR AVG ($PM_{2.5}$ 24-hour standard)
The 3-year average of the annual 98th percentiles of the individual 24-hour concentrations of $PM_{2.5}$. A 3-year average greater than 35 µg/m^3 at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.

3-YR AVG ($PM_{2.5}$ annual standard)
The 3-year average of the quarterly averages of $PM_{2.5}$. A 3-year average greater than 15 µg/m^3 at any monitoring station means that the region does not meet the standard and may be designated non-attainment by the EPA.

HEALTH-BASED AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California Std	National Std
Ozone	1 Hour	0.09 ppm	—
	8 Hour	0.070 ppm	0.075 ppm
Carbon Monoxide	1 Hour	20 ppm	35 ppm
	8 Hour	9.0 ppm	9 ppm
Nitrogen Dioxide	1 Hour	0.25 ppm	—
	Annual	—	0.053 ppm
Sulfur Dioxide	24 Hour	0.04 ppm	0.14 ppm
	Annual	—	0.030 ppm
Particulates ≤ 10 microns	24 Hour	50 µg/m^3	150 µg/m^3
	Annual	20 µg/m^3	—
Particulates ≤ 2.5 microns	24 Hour	—	35 µg/m^3
	Annual	12 µg/m^3	15 µg/m^3

Concentrations | **ppm** parts per million | **ppb** parts per billion | **µg/m^3** micrograms per cubic meter

TEN-YEAR BAY AREA AIR QUALITY SUMMARY

DAYS OVER STANDARDS

YEAR	OZONE			CARBON MONOXIDE				Nitrogen Dioxide	Sulfur Dioxide		PM_{10}		$PM_{2.5}$
	8-Hr* Nat	1-Hr Cal	8-Hr Cal	1-Hr Nat	1-Hr Cal	8-Hr Nat	8-Hr Cal	1-Hr Cal	24-Hr Nat	24-Hr Cal	24-Hr Nat	24-Hr Cal	24-Hr** Nat
1999	9	20	-	0	0	0	0	0	0	0	0	12	-
2000	4	12	-	0	0	0	0	0	0	0	0	7	1
2001	7	15	-	0	0	0	0	0	0	0	0	10	5
2002	7	16	-	0	0	0	0	0	0	0	0	6	7
2003	7	19	-	0	0	0	0	0	0	0	0	6	0
2004	0	7	-	0	0	0	0	0	0	0	0	7	1
2005	1	9	9	0	0	0	0	0	0	0	0	6	0
2006	12	18	22	0	0	0	0	0	0	0	0	15	10
2007	1	4	9	0	0	0	0	0	0	0	0	4	14
2008	12	9	20	0	0	0	0	0	0	0	0	5	12

*On May. 17, 2008, the U.S. EPA implemented a more stringent national 8-hour ozone standard , revising it from 0.08 ppm to 0.075 ppm. Ozone exceedance days for 2008 reflect the new standard.

**On Dec. 17, 2006, the U.S. EPA implemented a more stringent national 24-hour $PM_{2.5}$ standard—revising it from 65 µg/m^3 to 35 µg/m^3. Starting in 2006, $PM_{2.5}$ exceedance days reflect the new standard.

Table 5.1B-4A
OGS AERMOD Turbine Screening Results
Regular Receptor Grids
155.5' Stack Height

Case	**B**	**D**	**R**	**H**	**J**	**X**	**1E**	**1F**	**1G**
Evap Cooling	**On**	**Off**	**Off**	**On**	**Off**	**Off**	**Off**	**Off**	**Off**
Load %	**100**	**80**	**49**	**100**	**80**	**52**	**100**	**80**	**49**
Duct Firing	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Ambient Temp, °F	59	59	59	104	104	104	34	34	34
Stack Exit Temp (deg.F)	190.900	179.720	171.400	212.800	196.360	179.700	191.600	184.790	171.300
Volumetric Flowrate ACFM	1,150,000	910,000	743,000	1,181,000	889,000	760,000	1,162,000	1,005,000	739,000
Stack Inside Diameter (ft)	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37
Stack Height (m)	47.396	47.396	47.396	47.396	47.396	47.396	47.396	47.396	47.396
Stack Exit Temp (deg.K)	361.4	355.2	350.6	373.6	364.5	355.2	361.8	358.0	350.5
Stack Exit Velocity (m/s)	22.04	17.44	14.24	22.64	17.04	14.57	22.27	19.26	14.16
Stack Inside Diameter (m)	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992	5.5992
Normal Operations - Short-term Screening Emissions (lb/hr/turbine) and Unitized Screening Impacts (for 0.5 g/s/turbine)									
NOx (lb/hr/turbine)	15.17	12.50	9.66	14.75	11.47	9.25	15.52	13.88	9.91
CO (lb/hr/turbine)	9.24	7.61	5.88	8.98	6.98	5.63	9.45	8.45	6.04
SO2 (lb/hr/turbine)	5.90	4.80	3.70	5.70	4.40	3.60	6.00	5.40	3.80
PM10 (lb/hr/turbine)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
1-Hr Unitized Conc (ug/m3)	5.62868	7.01324	8.31401	5.00844	6.68692	7.90908	5.56554	6.41791	8.34888
X(m)	610450.0	610430.0	610420.0	610470.0	610430.0	610420.0	610450.0	610440.0	610420.0
Y(m)	4207160.0	4207180.0	4207190.0	4207150.0	4207180.0	4207190.0	4207160.0	4207170.0	4207190.0
YYMMDDHH	02090213	02090213	02090213	02090213	02090213	02090213	02090213	02090213	02090213
3-Hr Unitized Conc (ug/m3)	4.27619	5.28706	6.42373	3.85022	5.04295	6.08875	4.22565	4.77794	6.45389
X(m)	610470.0	610460.0	610440.0	610480.0	610470.0	610450.0	610470.0	610470.0	610440.0
Y(m)	4207150.0	4207100.0	4207120.0	4207140.0	4207090.0	4207110.0	4207150.0	4207090.0	4207120.0
YYMMDDHH	01073115	04072512	04072512	01073115	04072512	04072512	01073115	04072512	04072512
8-Hr Unitized Conc (ug/m3)	3.18684	3.90023	4.62268	2.69915	3.72763	4.40549	3.14624	3.56110	4.64403
X(m)	610500.0	610490.0	610470.0	610500.0	610500.0	610470.0	610500.0	610500	610470.0
Y(m)	4207110.0	4207120.0	4207130.0	4207100.0	4207110.0	4207130.0	4207110.0	4207110.0	4207130.0
YYMMDDHH	04081016	04081016	04081016	04081016	04081016	04081016	04081016	04081016	04081016
24-Hr Unitized Conc (ug/m3)	1.16440	1.44724	1.76969	0.98466	1.37713	1.64308	1.14899	1.31385	1.77873
X(m)	610500.0	610500.0	610480.0	610500.0	610500.0	610490.0	610500.0	610500.0	610480.0
Y(m)	4207110.0	4207110.0	4207130.0	4207110.0	4207110.0	4207120.0	4207110.0	4207110.0	4207130.0
YYMMDDHH	04081024	04081024	04081024	04081024	04081024	04081024	04081024	04081024	04081024
Normal Operations - Short-term Pollutant Emissions (g/s/turbine) and Pollutant Screening Impacts									
NOx (g/s/turbine)	1.912	1.575	1.217	1.858	1.445	1.165	1.956	1.749	1.249
CO (g/s/turbine)	1.164	0.959	0.741	1.131	0.880	0.709	1.191	1.065	0.760
SO2 (g/s/turbine)	0.743	0.605	0.466	0.718	0.554	0.454	0.756	0.680	0.479
PM10 (g/s/turbine)	1.134	1.134	1.134	1.134	1.134	1.134	1.134	1.134	1.134
1-Hour NOx (ug/m3)	21.524	22.092	20.236	18.611	19.325	18.428	21.772	**22.450**	20.856
1-Hour CO (ug/m3)	13.104	13.451	12.321	11.329	11.769	11.215	13.257	**13.670**	12.690
8-Hour CO (ug/m3)	4.736	4.719	4.308	3.876	4.130	4.000	4.757	**4.843**	4.449
1-Hour SO2 (ug/m3)	8.364	8.486	7.749	7.192	7.409	7.181	8.415	**8.728**	7.998
3-Hour SO2 (ug/m3)	16.352	16.654	15.635	14.307	14.574	14.187	16.531	**16.713**	16.122
24-Hour SO2 (ug/m3)	1.730	1.751	1.649	1.414	1.526	1.492	1.737	**1.787**	1.704
24-Hour PM10 (ug/m3)	2.641	3.282	4.014	2.233	3.123	3.727	2.606	2.980	**4.034**

Worst-Case Operating Scenarios are **bolded**.

Keyword: **FASTALL**

Table 5.1B-4B
Emission Rates and Stack Parameters for Modeling

	Stack Height meters	Temp, deg K	Exhaust Velocity, m/s	Stack Diam, m	Emission Rates, g/s				Emission Rates, lb/hr			
					NOx	SO2	CO	PM10	NOx	SO2	CO	PM10
Averaging Period: One hour												
Turbine N/HRSG	47.396	358.0	19.26	5.5992	1.956	0.756	1.191	-	15.52	6	9.45	-
Turbine S/HRSG	47.396	358.0	19.26	5.5992	1.956	0.756	1.191	-	15.52	6	9.45	-
Fire Pump	4.877	714.26	32.22	0.2032	2.706E-01	5.040E-04	0.087	-	2.148	0.004	0.691	0.085
Aux Boiler	15.240	416.48	15.08	0.7620	5.292E-02	1.764E-02	0.047	-	0.42	0.14	0.37	0.354
Averaging Period: Three hours												
Turbine N/HRSG	47.396	358.0	19.26	5.5992	-	0.756	-	-	-	6	-	-
Turbine S/HRSG	47.396	358.0	19.26	5.5992	-	0.756	-	-	-	6	-	-
Fire Pump	4.877	714.26	32.22	0.2032	-	1.680E-04	-	-	-	1.33E-03	-	-
Aux Boiler	15.240	416.48	15.08	0.7620	-	1.764E-02	-	-	-	0.14	-	-
Averaging Period: Eight hours												
Turbine N/HRSG	47.396	358.0	19.26	5.5992	-	-	1.191	-	-	-	9.45	-
Turbine S/HRSG	47.396	358.0	19.26	5.5992	-	-	1.191	-	-	-	9.45	-
Fire Pump	4.877	714.26	32.22	0.2032	-	-	0.0109	-	-	-	0.086	-
Aux Boiler	15.240	416.48	15.08	0.7620	-	-	0.012	-	-	-	0.093	-
Averaging Period: 24 hours												
Turbine N/HRSG	47.396	350.5	14.16	5.5992	-	0.756	-	1.134	-	6	-	9.000
Turbine S/HRSG	47.396	350.5	14.16	5.5992	-	0.756	-	1.134	-	6	-	9.000
Fire Pump	4.877	714.26	32.22	0.2032	-	2.100E-05	-	4.463E-04	-	1.67E-04	-	3.542E-03
Aux Boiler	15.240	416.48	15.08	0.7620	-	1.470E-03	-	3.717E-03	-	0.0117	-	0.0295
Evap Cooler per cell	7.010	304.21	10.19	3.353	-	-	-	5.544E-03	-	-	-	0.0440
Averaging Period: Annual												
Turbine N/HRSG	47.396	361.4	22.04	5.5992	1.418	0.181	-	1.096	11.26	1.44	-	8.699
Turbine S/HRSG	47.396	361.4	22.04	5.5992	1.418	0.181	-	1.096	11.26	1.44	-	8.699
Fire Pump	4.877	714.26	32.22	0.2032	1.514E-03	2.819E-06	-	5.991E-05	1.202E-02	2.237E-05	-	4.755E-04
Aux Boiler	15.240	416.48	15.08	0.7620	2.435E-03	8.115E-04	-	2.052E-03	0.019	6.441E-03	-	0.016
Evap Cooler per cell	7.010	304.21	10.19	3.353	-	-	-	9.493E-04	-	-	-	0.0075
Cold Start (worst case) One hour												
Turbine N/HRSG	47.396	350.5	14.16	5.5992	12.585	-	45.658	-	99.88	-	362.3625	-
Turbine S/HRSG	47.396	350.5	14.16	5.5992	12.585	-	45.658	-	99.88	-	362.3625	-
Fire Pump	4.877	714.26	32.22	0.2032	-	-	-	-	-	-	-	-
Aux Boiler	15.240	416.48	15.08	0.7620	5.292E-02	-	0.047	-	0.42		0.37	-
Cold Start (worst case) 8 hour												
Turbine N/HRSG	47.396	350.5	14.16	5.5992	-	-	10.218	-	-	-	81.098	-
Turbine S/HRSG	47.396	350.5	14.16	5.5992	-	-	10.218	-	-	-	81.098	-
Fire Pump	4.877	714.26	32.22	0.2032	-	-	0.0109	-	-	-	0.086	-
Aux Boiler	15.240	416.48	15.08	0.7620	-	-	0.012	-	-	-	0.093	-
Commissioning One hour												
Turbine N/HRSG	47.396	350.5	14.16	5.5992	18.736	-	88.200	-	148.7	-	700	-
Turbine S/HRSG	47.396	350.5	14.16	5.5992	12.585	-	45.658	-	99.88	-	362.3625	-
Aux Boiler	15.240	416.48	15.08	0.7620	5.292E-02	-	0.047	-	0.42		0.37	-
Commissioning 8 hour												
Turbine N/HRSG	47.396	350.5	14.16	5.5992	-	-	88.200	-	-	-	700	-
Turbine S/HRSG	47.396	350.5	14.16	5.5992	-	-	10.218	-	-	-	81.098	-
Fire Pump	4.877	714.26	32.22	0.2032	-	-	0.0109	-	-	-	0.086	-
Aux Boiler	15.240	416.48	15.08	0.7620	-	-	0.047	-	-	-	0.370	-

Assumptions:

Aux boiler operation is 24 hours per day and 4324 hour per year for CO
Aux boiler operation is 24 hours per day and 403 hours per year for NOx, PM, SO2
Fire pump operates up to 56 minutes per day, 49 hours year
Evap cooler operates 24 hours per day and 1500 hours per year
Turbine operates 24 hours per day for all cases and pollutants
SO2 24-hour impacts based on 358 Kelvein and 19.26 m/s stack parameters
Annual NOx, SOx, PM: 6924 hours base load, 1500 hours peak load, 51 hot starts, 1 cold start, 52 shutdowns for a total of 39 hours in startup/shutdown = 8463 hours
Cold start is 60 minutes which is the worst case start
CO 8-hour impacts calculated as 1 cold start + one shutdown +one hot start + 5 hours base load
Fire pump not tested during 1 hour start cycle
Aux boiler assumed to operate 8 hours for 8-hour CO startup modeling and commissioning

Table 5.1B-5

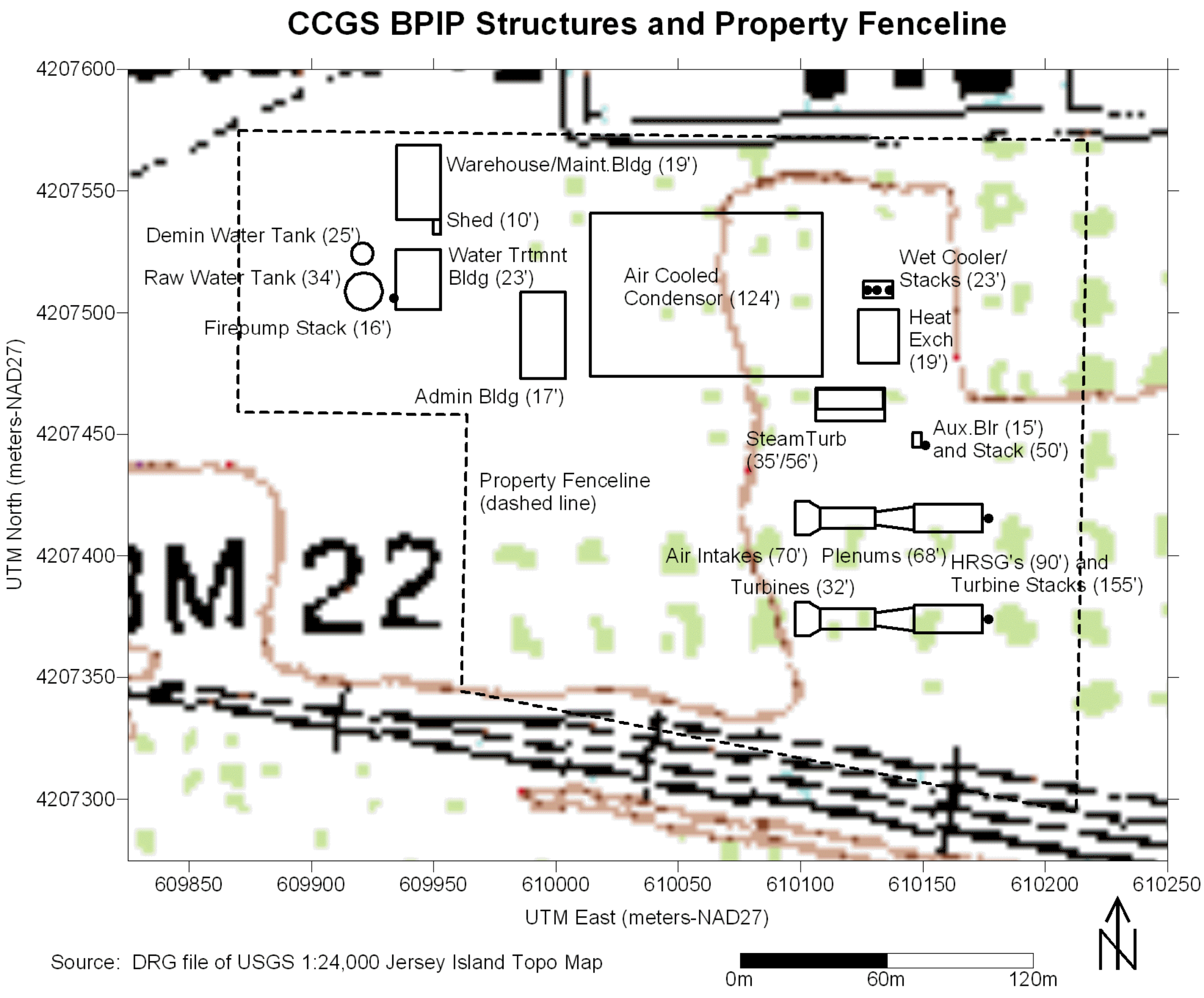
Modeling Inputs/Results for OGS Construction Impacts (Combustion Sources as 29 Point Sources) - FASTALL Option/10m+Fenceline Recs

Short Term Impacts (24 hrs and less)						Long Term Impacts (annual)					
	NOx	CO	SOx	PM10	PM2.5		NOx	CO	SOx	PM10	PM2.5
Combustion (lbs/day)	106.3	54.1	0.12	6.14	6.10	Combustion (tons/year)	14.04	7.13	0.0036	0.811	0.804
						Combustion (days/year)**	288	288	288	288	288
Combustion (hrs/day)	10	10	10	10	10	Combustion (hrs/day)	10	10	10	10	10
Combustion (lbs/hr)	10.63	5.41	0.01	0.61	0.61	Combustion (lbs/hr)**	7.69	3.91	0.00	0.44	0.44
Combustion (g/sec)	1.34E+00	6.82E-01	1.51E-03	7.74E-02	7.69E-02	Combustion (g/sec)	9.69E-01	4.92E-01	2.49E-04	5.60E-02	5.55E-02
Construction Dust (lbs/day)				12.70	2.70	Construction Dust (tons/year)				0.498	0.095
						Construction Dust (days/year)				288	288
Construction Dust (hrs/day)				10	10	Construction Dust (hrs/day)				10	10
Construction Dust (lbs/hr)				1.27	0.27	Construction Dust (lbs/hr)**				0.273	0.052
Construction Dust (g/sec)	18.46	acres		1.60E-01	3.40E-02	Construction Dust (g/sec)				3.44E-02	6.56E-03
AERMOD Inputs	**74,689**	**m^2**	**29**	**Pt.Srcs**							
Combustion (g/s/src)	4.619E-02	2.351E-02	5.214E-05	2.668E-03	2.650E-03	Combustion (g/s/src)	3.343E-02	1.697E-02	8.571E-06	1.931E-03	1.914E-03
Construction Dust (g/s/m^2)				2.142E-06	4.555E-07	Construction Dust (g/s/m^2)				4.603E-07	8.782E-08
AERMOD Results (ug/m^3)											
Combustion Only						Combustion Only					
1-hour Max	89.935*	47.682	0.106	5.41162							
3-hour Max			0.075	3.85228							
8-hour Max		17.657		2.00396							
24-hour Max			0.020	1.00133	0.99481	Annual	5.393		0.001	0.31153	0.30884
All Particulate Sources						All Particulate Sources					
24-hour Max				96.38640	20.61274	Annual				2.31165	0.60053
5-Year Average 8th Highest 1-hr Max Daily NO2	94.071*	Includes Concurrent Hourly NO2 Background Concentrations				Annual NO2 w/ ARM	4.045	based on ARM Ratio of:		75%	
Background (ug/m^3)						Background (ug/m^3)					
1-hour Max	98.1	3771	122.2								
3-hour Max			65.0								
8-hour Max		2171									
24-hour Max			23.4	82	35	Annual	20.8		7.8	24.0	9.0
Total + Background (ug/m^3)						Total + Background (ug/m^3)					
1-hour Max	188.0	3819	122.3								
3-hour Max			65.08								
8-hour Max		2189									
24-hour Max			23.42	178.4	55.6	Annual	24.8		7.8	26.3	9.6

*Based on AERMOD Ozone Limiting Method (OLM) keyword with facility sources combined in one source group. Combined 1-hour NO2 impacts for comparison to standards are 188.0 ug/m3 for 1-hour CAAQS of 339 ug/m3 (maximum impact) and 94.1 ug/m3 for 1-hour NAAQS of 188 ug/m3 (maximum 5-year average of 8th highest 1-hour daily max's).

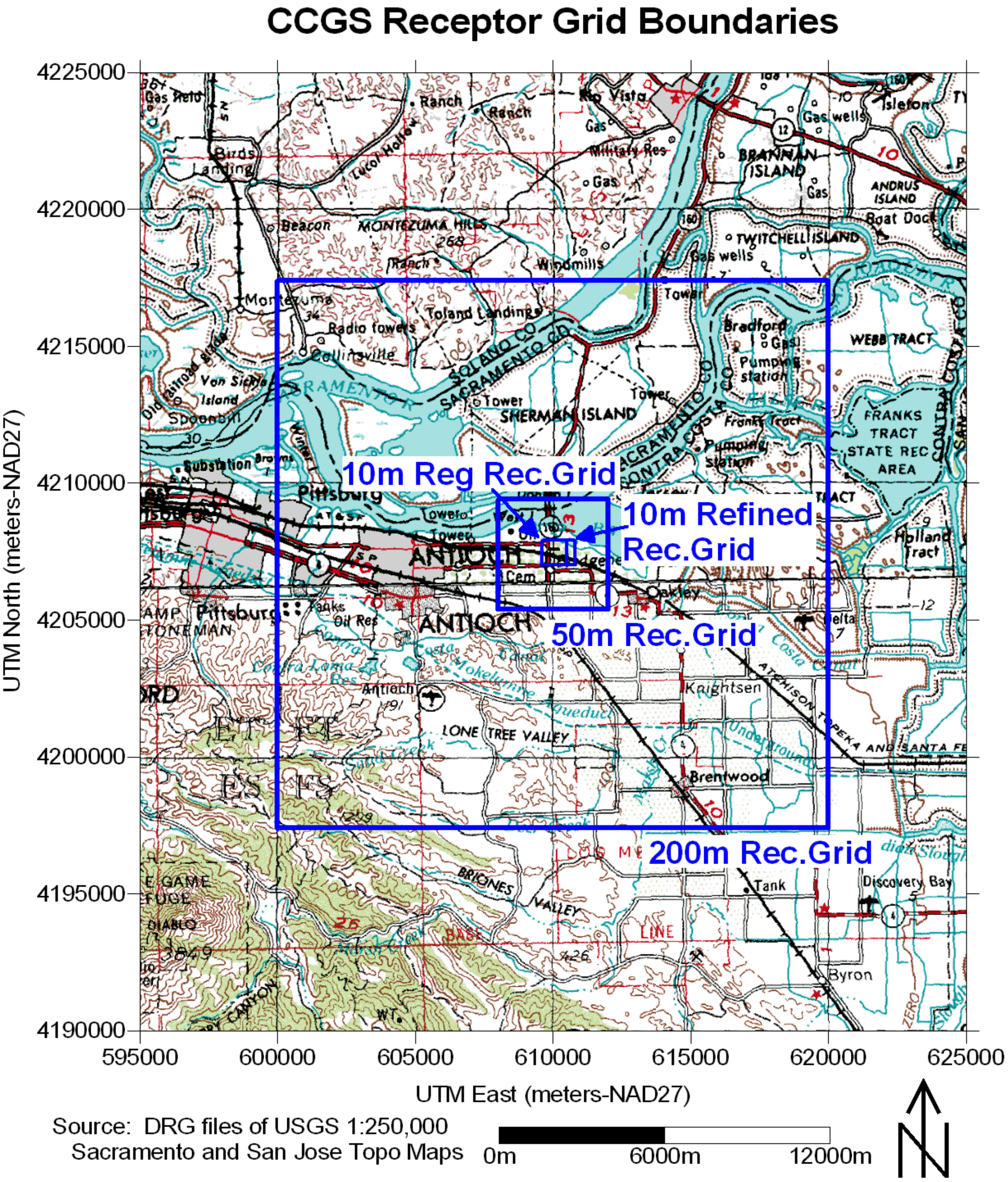
**Even for construction projects taking less than 12-months or 7 days/wk, the hourly emissions for modeling are still based on total tons (projects<12 months) or tons/year (projects>12months) divided by 365 days since all days in the met dataset (i.e., all 12 months and all 365 days - i.e., 7 days/week) are modeled.

Figure 5.1B-1 Facility BPIP Modeling Plot



Source: DRG file of USGS 1:24,000 Jersey Island Topo Map

Figure 5.1B-2 Coarse and Fine Receptor Grid



Source: DRG files of USGS 1:250,000 Sacramento and San Jose Topo Maps

Figure 5.1B-3 Bay Area Air Basin Monitoring Stations

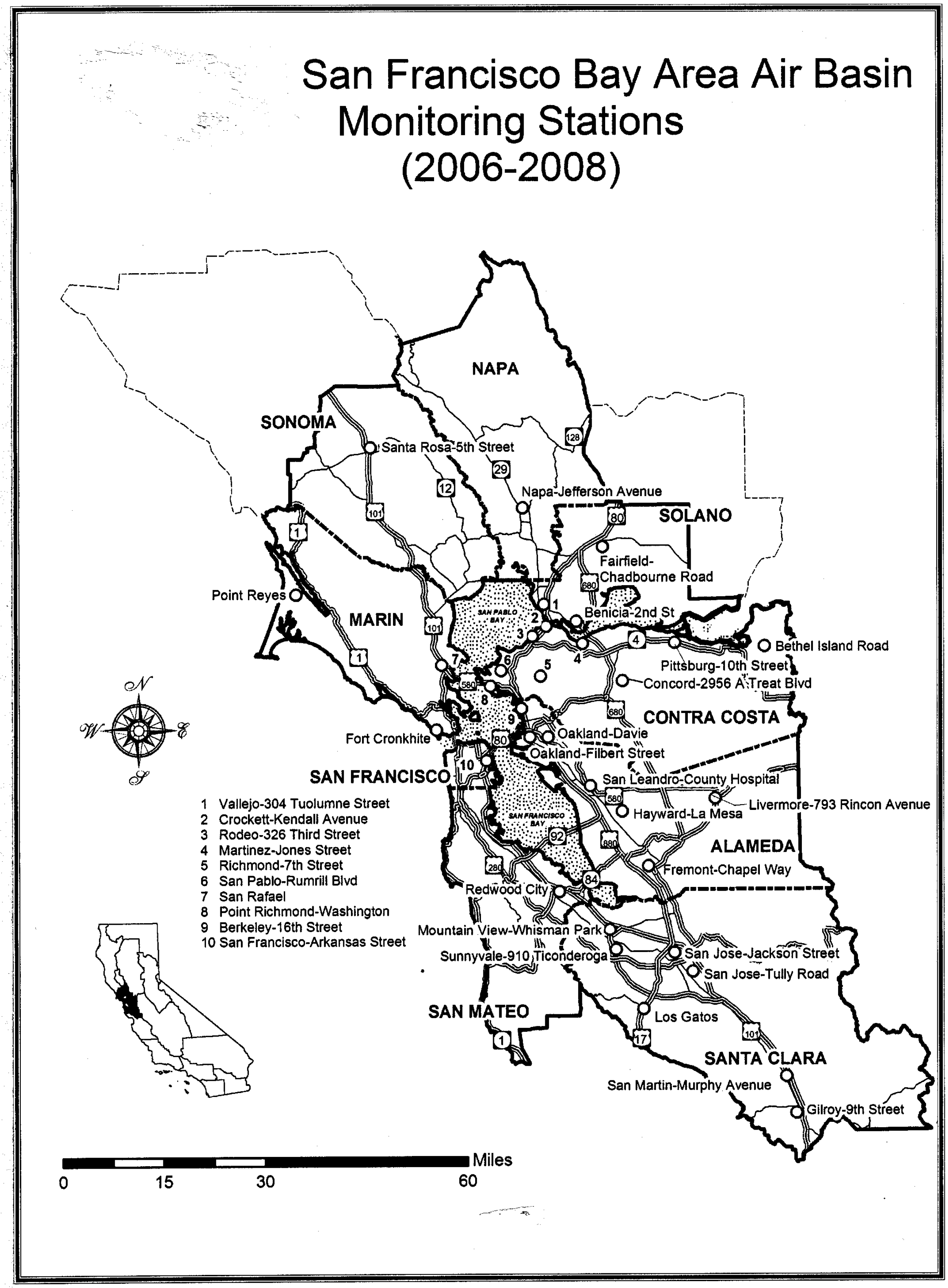


Figure 5.1B-4

Annual CCP Meteorological Monitoring Station Wind Rose
(2001-2006)

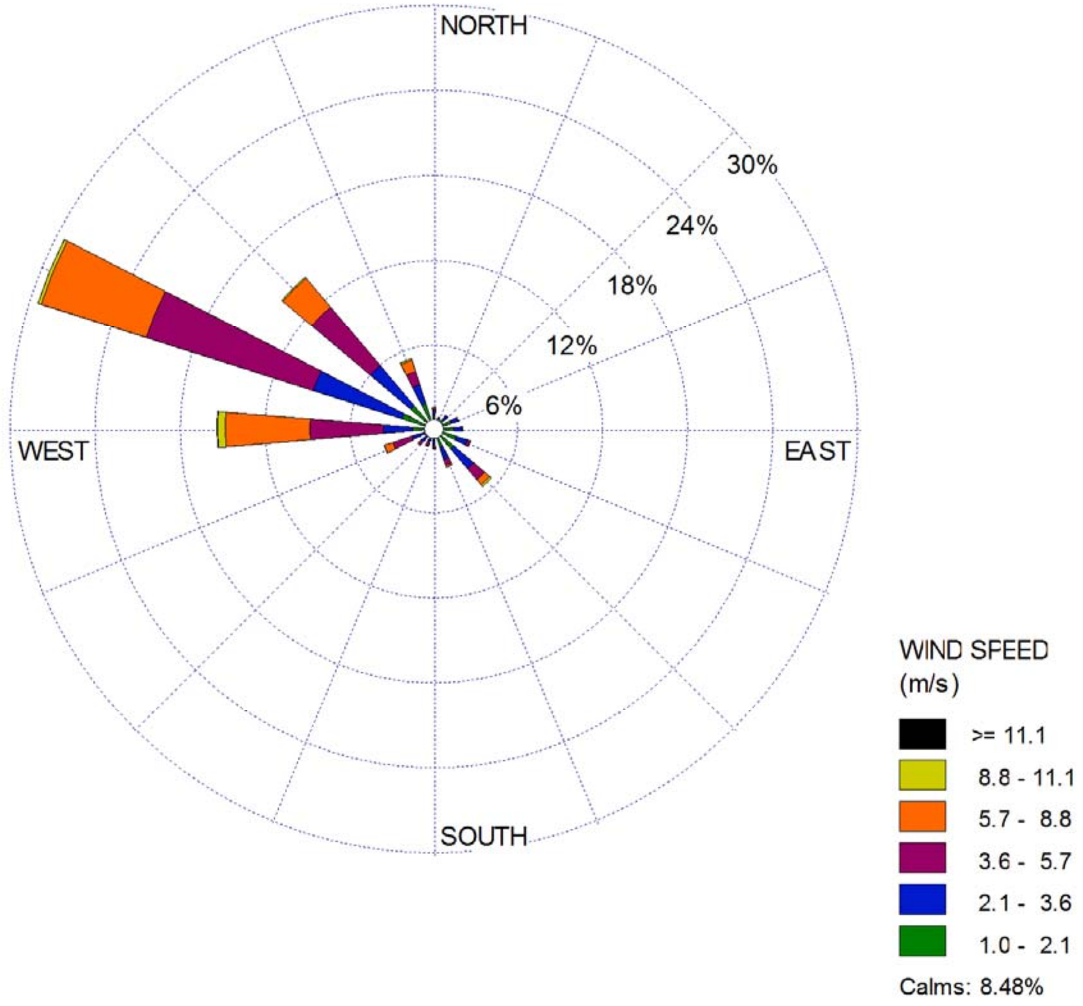


Figure 5.1B-5

Winter CCP Meteorological Monitoring Station Wind Rose
(2001-2006)

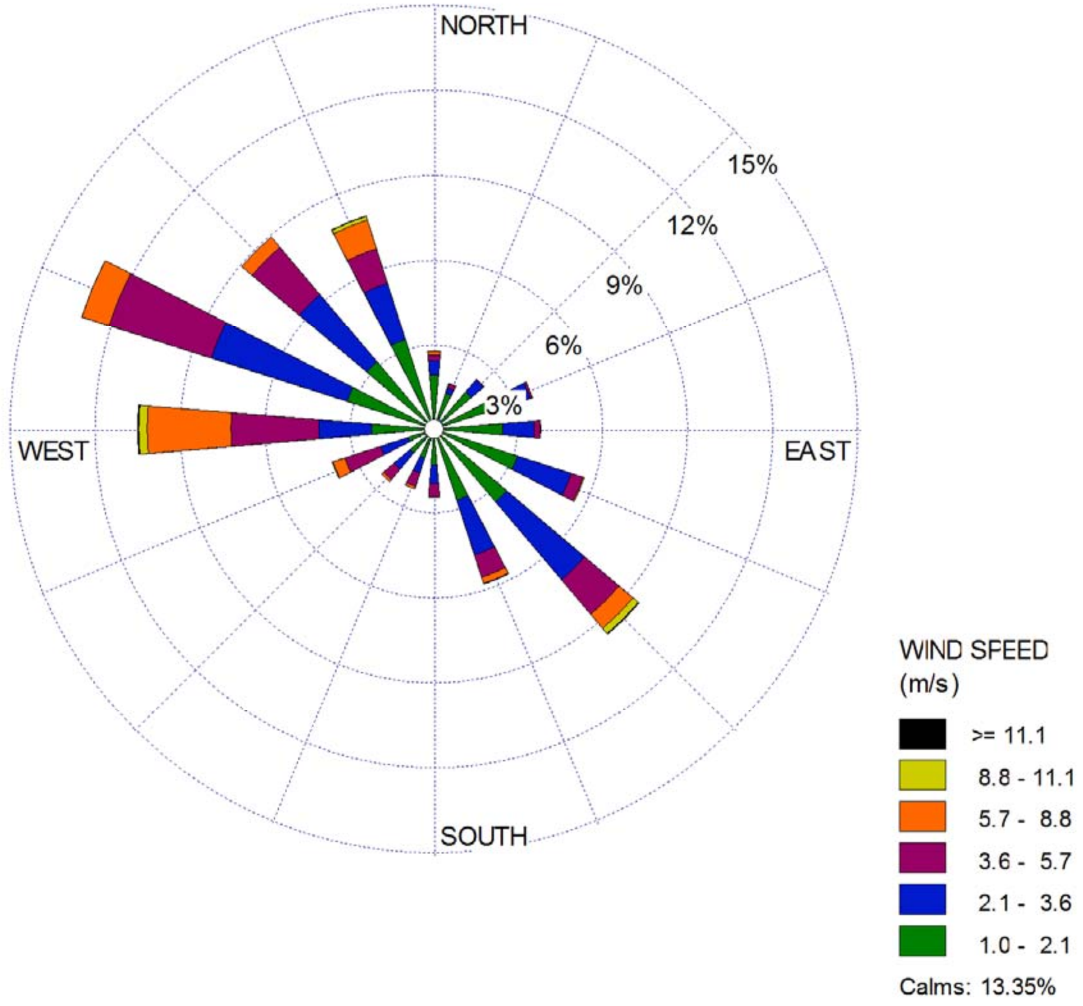


Figure 5.1B-6

Spring CCP Meteorological Monitoring Station Wind Rose
(2001-2006)

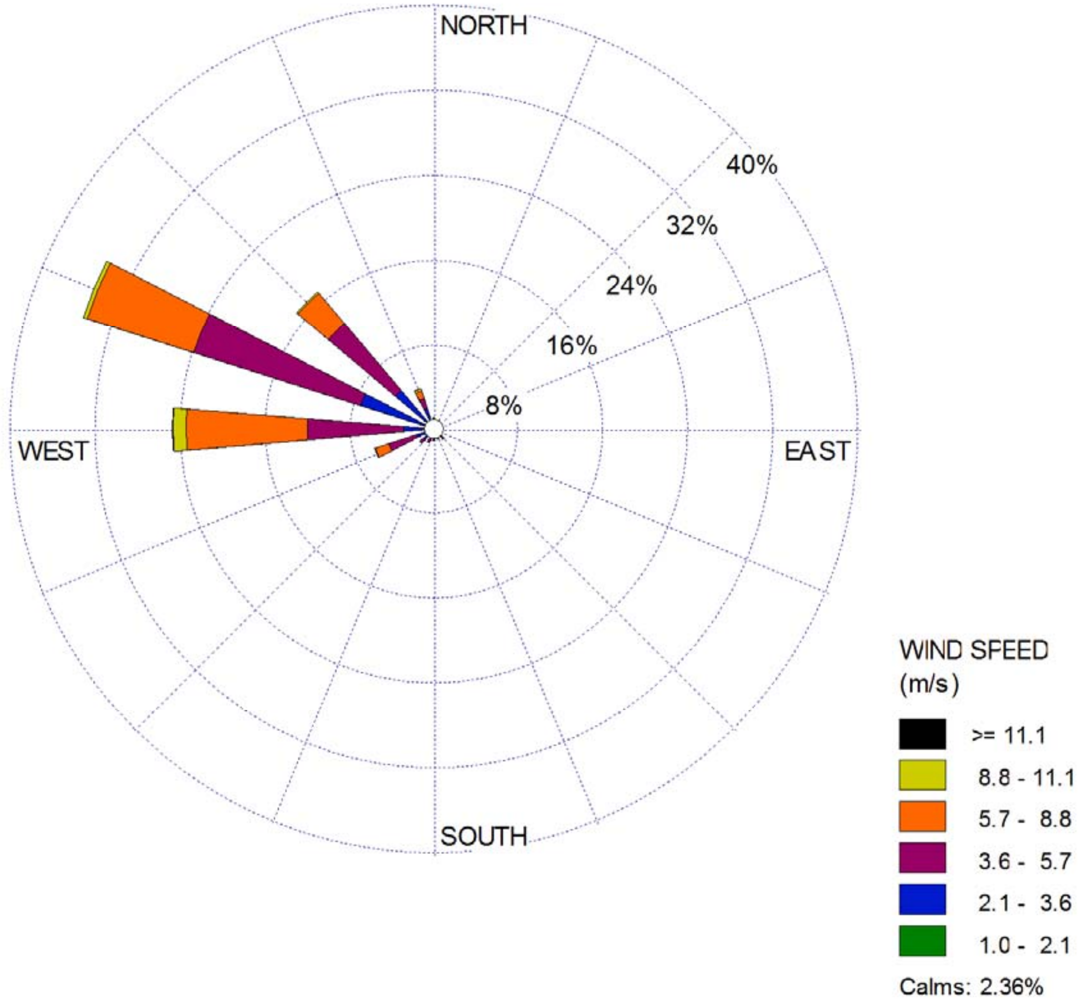


Figure 5.1B-7

Summer CCP Meteorological Monitoring Station Wind Rose
(2001-2006)

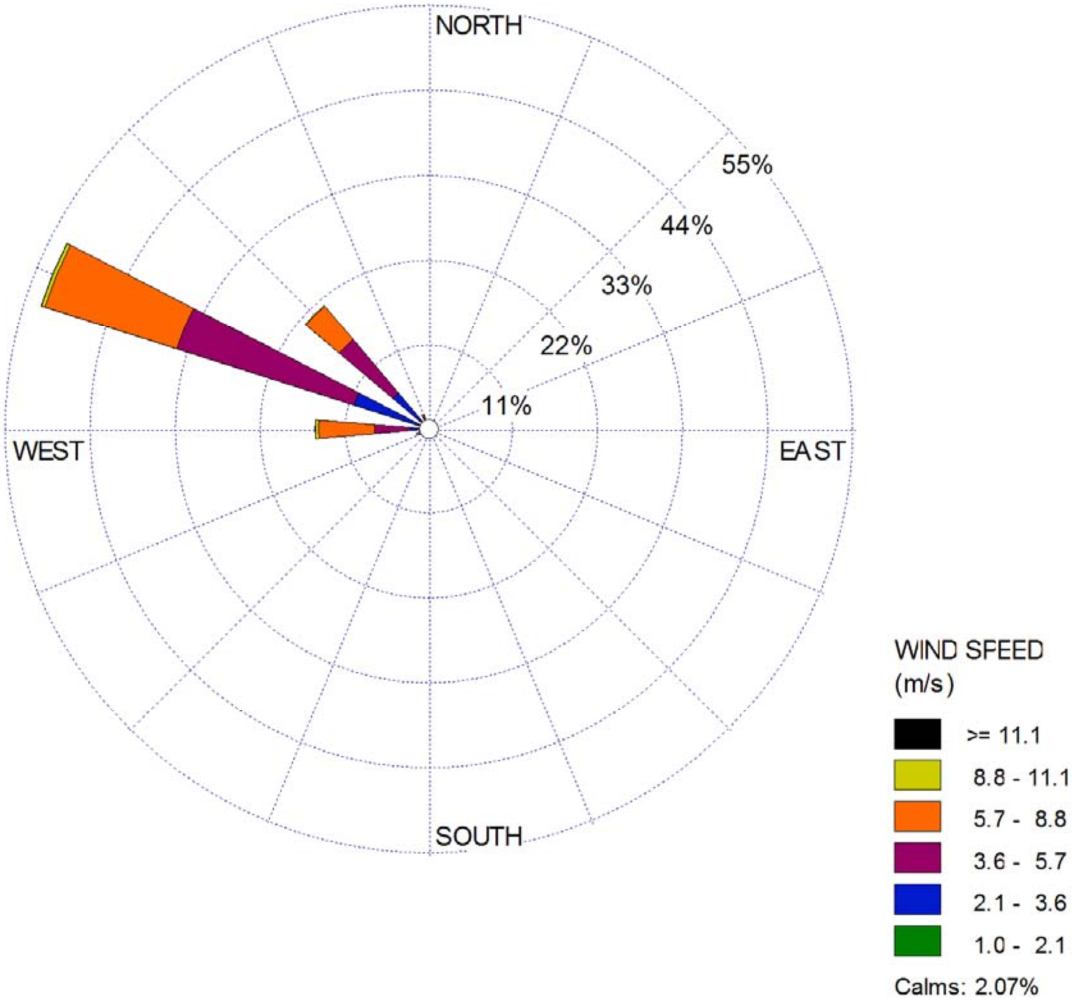
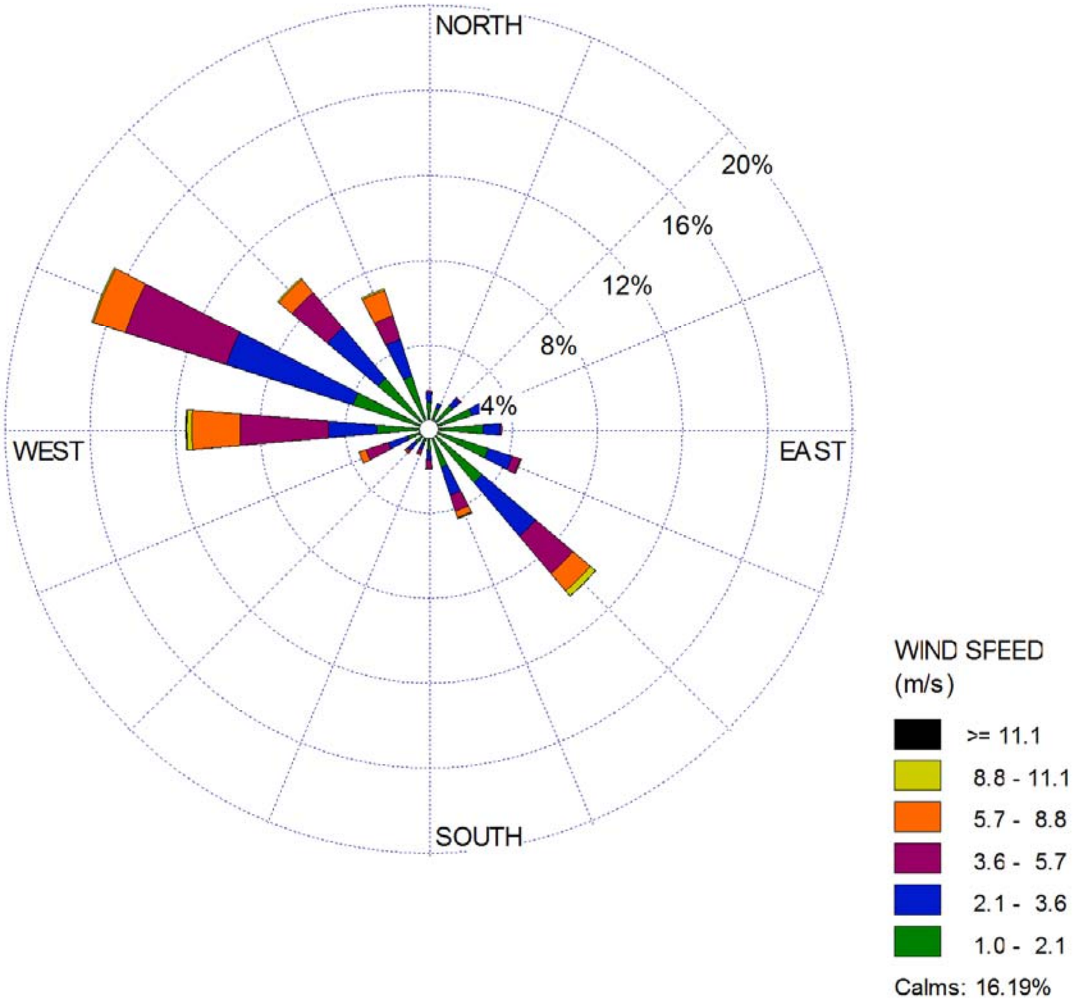


Figure 5.1B-8

Fall CCP Meteorological Monitoring Station Wind Rose
(2001-2006)



APPENDIX 5.1C

No Changes to this Appendix

Appendix 5.1C intentionally left out.

APPENDIX 5.1D

Health Risk Assessment Support Data

Appendix 5.1D

Health Risk Assessment Support Data

Health Risk Assessment Process, Goals, Assumptions, and Uses

In recent years, the public has become increasingly aware of the presence of harmful chemicals in our environment. Many people express concerns about pesticides and other foreign substances in food, contaminants in drinking water, and toxic pollutants in the air. Others believe these concerns are exaggerated or unwarranted. How can we determine which of these potential hazards really deserve attention? How do we, as a society, decide where to focus our efforts and resources to control these hazards? When we hear about toxic threats that affect us personally, such as the discovery of industrial waste buried in our neighborhood or near our children's school, how concerned should we be?

Health risk assessment is a scientific tool designed to help answer these questions. Government agencies rely on risk assessments to help them determine which potential hazards are the most significant. Risk assessments can also guide regulators in abating environmental hazards. Members of the public who learn the basics of risk assessment can improve their understanding of both real and perceived environmental hazards, and they can work more effectively with decision makers on solutions to environmental problems.

Chemicals can be either beneficial or harmful, depending on a number of factors, such as the amounts to which we are exposed. Low levels of some substances may be necessary for good health, but higher levels may be harmful. Health risk assessments are used to determine if a particular chemical poses a significant risk to human health and, if so, under what circumstances. Could exposure to a specific chemical cause significant health problems? How much of the chemical would someone have to be exposed to before it would be dangerous? How serious could the health risks be? What activities might put people at increased risk?

If it were possible to prevent all human exposure to all hazardous chemicals, there would be no need for risk assessment. However, the total removal of harmful pollutants from the environment is often infeasible or impossible, and many naturally occurring substances also pose health risks. Risk assessment helps scientists and regulators identify serious health hazards and determine realistic goals for reducing exposure to toxics so that there is no significant health threat to the public.

Estimating the hazards posed by toxic chemicals in the environment involves the compilation and evaluation of complex sets of data. Government regulators, therefore, turn to specialists to perform or assist with risk assessments. These specialists include scientists with degrees in toxicology (the study of the toxic effects of chemicals) and epidemiology (the study of disease or illness in populations) as well as physicians, biologists, chemists, and engineers.

The term "health risk assessment" is often misinterpreted. People sometimes think that a risk assessment will tell them whether a current health problem or symptom was caused by exposure to a chemical. This is not the case. Scientists who are searching for links between chemical exposures and health problems in a community may conduct an epidemiologic study. These studies typically include a survey of health problems in a community and a comparison of health problems in that community with those in other cities, communities, or the population as a whole.

Although they are both important, health risk assessments and epidemiologic studies have different objectives. Most epidemiologic studies evaluate whether *past* chemical exposures may be responsible for documented health problems in a specific group of people. In contrast, health risk assessments are used to estimate whether *current* or *future* chemical exposures will pose health risks to a broad population, such as a city or a community. Scientific methods used in health risk assessment cannot be used to link individual illnesses to past chemical exposures, nor can health risk assessments and epidemiologic studies prove that a specific toxic substance caused an individual's illness.

The U.S. Environmental Protection Agency (U.S. EPA) is a leading risk assessment agency at the federal level. In California, the Office of Environmental Health Hazard Assessment (OEHHA) in the California Environmental Protection Agency (Cal/EPA) has the primary responsibility for developing procedures and practices for performing health risk assessments. Other agencies within Cal/EPA, such as the Department of Pesticide Regulation and the Department of Toxic Substances Control, have extensive risk assessment programs of their own but work closely with OEHHA.

The Department of Pesticide Regulation uses risk assessments to make regulatory decisions concerning safe pesticide uses. The Department of Toxic Substances Control uses risk assessments to determine requirements for the management and cleanup of hazardous wastes. OEHHA's health risk assessments are used by the Air Resources Board to develop regulations governing toxic air contaminants, and by the Department of Health Services to develop California's drinking water standards. These agencies' decisions take into account the seriousness of potential health effects along with the economic and technical feasibility of measures that can reduce the health risks.

Health risk assessment requires both sound science and professional judgment and is a constantly developing process. Cal/EPA is nationally recognized for developing new procedures that improve the accuracy of risk assessments. Cal/EPA also works closely with U.S. EPA in all phases of risk assessment.

The risk assessment process is typically described as consisting of four basic steps: hazard identification, exposure assessment, dose-response assessment, and risk characterization. Each of these steps will be explained in the following text.

Hazard Identification

In the first step, hazard identification, scientists determine the types of health problems a chemical could cause by reviewing studies of its effects in humans and laboratory animals. Depending on the chemical, these health effects may include short-term ailments, such as headaches; nausea; and eye, nose, and throat irritation; or chronic diseases, such as cancer. Effects on sensitive populations, such as pregnant women and their developing fetuses, the elderly, or those with health problems (including those with weakened immune systems), must also be considered. Responses to toxic chemicals will vary depending on the amount and length of exposure. For example, short-term exposure to low concentrations of chemicals may produce no noticeable effect, but continued exposure to the same levels of chemicals over a long period of time may eventually cause harm.

An important step in hazard identification is the selection of key research studies that can provide accurate, timely information on the hazards posed to humans by a particular chemical. The selection of a study is based upon factors such as whether the study has been peer reviewed by qualified scientists, whether the study's findings have been verified by other studies, and the species tested (human studies provide the best evidence). Some studies may involve humans that have been exposed to the chemical, while others may involve studies with laboratory animals.

Human data frequently are useful in evaluating human health risks associated with chemical exposures. Human epidemiologic studies typically examine the effects of chemical exposure on a large number of people, such as employees exposed to varying concentrations of chemicals in the workplace. In many cases, these exposures took place prior to the introduction of modern worker-safety measures.

One weakness of occupational studies is that they generally measure the effects of chemicals on healthy workers and do not consider children, the elderly, those with pre-existing medical conditions, or other sensitive groups. Since occupational studies are not controlled experiments, there may be uncertainties about the amount and duration of exposure or the influence of lifestyle choices, such as smoking or alcohol use, on the health of workers in the studies. Exposure of workers to other chemicals at the same time may also influence and complicate the results.

Laboratory studies using human volunteers are better able to gauge some health effects because chemical exposures can then be measured with precision. But these studies usually involve small numbers of people and, in conformance with ethical and legal requirements, use only adults who agree to participate in the studies. Moreover, laboratory studies often use simple measurements that identify immediate responses to the chemical but might miss significant, longer-term health effects. Scientists can also use physicians' case reports of an industrial or transportation accident in which individuals were unintentionally exposed to a chemical. However, these reports may involve very small numbers of people, and the level of exposure to the chemical could be greater than exposures to the same chemical in the environment. Nevertheless, human studies are preferred for risk assessment, so OEHHA makes every effort to use them when they are available.

Because the effects of the vast majority of chemicals have not been studied in humans, scientists must often rely on animal studies to evaluate a chemical's health effects. Animal studies have the advantage of being performed under controlled laboratory conditions that reduce much of the uncertainty related to human studies. If animal studies are used, scientists must determine whether a chemical's health effects in humans are likely to be similar to those in the animals tested. Although effects seen in animals can also occur in humans, there may be subtle or even significant differences in the ways humans and experimental animals react to a chemical. Comparison of human and animal metabolism may be useful in selecting the animal species that should be studied, but it is often not possible to determine which species is most like humans in its response to a chemical exposure. However, if similar effects were found in more than one species, the results would strengthen the evidence that humans may also be at risk.

Exposure Assessment

In exposure assessment, scientists attempt to determine how long people were exposed to a chemical; how much of the chemical they were exposed to; whether the exposure was continuous or intermittent; and how people were exposed—through eating, drinking water and other liquids, breathing, or skin contact. All of this information is combined with factors such as breathing rates, water consumption, and daily activity patterns to estimate how much of the chemical was taken into the bodies of those exposed.

People can be exposed to toxic chemicals in various ways. These substances can be present in the air we breathe, the food we eat, or the water we drink. Some chemicals, due to their particular characteristics, may be both inhaled and ingested. For example, airborne chemicals can settle on the surface of water, soil, leaves, fruits, vegetables, and forage crops used as animal feed. Cows, chickens, or other livestock can become contaminated when eating, drinking, or breathing the chemicals present in the air, water, feed, and soil. Fish can absorb the chemicals as they swim in contaminated water or ingest contaminated food. Chemicals can be absorbed through the skin, so infants and children can be exposed simply by crawling or playing in contaminated dirt. They can also ingest chemicals if they put their fingers or toys in their mouths after playing in contaminated dirt. Chemicals can also be passed on from nursing mothers to their children through breast milk.

To estimate exposure levels, scientists rely on air, water, and soil monitoring; human blood and urine samples; or computer modeling. Although monitoring of a pollutant provides excellent data, it is time consuming, costly, and typically limited to only a few locations. For those reasons, scientists often rely on computer modeling, which uses mathematical equations to describe how a chemical is released and to estimate the speed and direction of its movement through the surrounding environment. Modeling has the advantage of being relatively inexpensive and less time consuming, provided all necessary information is available and the accuracy of the model can be verified through testing.

Computer modeling is often used to assess chemical releases from industrial facilities. Such models require information on the type of chemicals released, facilities' hours of operation, industrial processes that release the chemicals, smokestack height and temperature, any pollution-control equipment that is used, surrounding land type (urban or rural), local topography and meteorology, and census data regarding the exposed population.

In all health risk assessments, scientists must make assumptions in order to estimate human exposure to a chemical. For example, scientists assessing the effects of air pollution may need to make assumptions about the time people spend outdoors, where they are more directly exposed to pollutants in the ambient air, or the time they spend in an area where the pollution is greatest. An assessment of soil contamination may require scientists to make assumptions about people's consumption of fruits and vegetables that may absorb soil contaminants.

To avoid underestimating actual human exposure to a chemical, scientists often look at the range of possible exposures. For example, people who jog in the afternoon, when urban air pollution levels are highest, would have much higher exposures to air pollutants than people who come home after work and relax indoors. Basing an exposure estimate on a value near the higher end of a range of exposure levels (closer to the levels experienced by the jogger than by the person remaining indoors) provides a realistic worst-case estimate of exposure. These kinds of conservative assumptions, which presume that people are exposed to the highest amounts of a chemical that can be considered credible, are referred to as "health-protective" assumptions.

The exposure estimates for the project analysis were conducted using HARP. HARP (version 1.4a) is currently the approved model for use in assessing health risks from faciliies such as the CCGS

Expansion project. HARP-On Ramp was also used to accommodate and process the AERMOD output files for use in HARP.

Dose-Response Assessment

In dose-response assessment, scientists evaluate the information obtained during the hazard identification step to estimate the amount of a chemical that is likely to result in a particular health effect in humans.

An established principle in toxicology is that "the dose makes the poison." For example, a commonplace chemical like table salt is harmless in small quantities, but it can cause illness in large doses. Similarly, hydrochloric acid, a hazardous chemical, is produced naturally in our stomachs but can be quite harmful if taken in large doses.

Scientists perform a dose-response assessment to estimate how different levels of exposure to a chemical can impact the likelihood and severity of health effects. The dose-response relationship is often different for many chemicals that cause cancer than it is for those that cause other kinds of health problems.

The dose-response estimates for the project analysis were conducted using HARP (version 1.4a).

Cancer Effects

For chemicals that cause cancer, the general assumption in risk assessment has been that there are no exposures that have "zero risk" unless there is clear evidence otherwise. In other words, even a very low exposure to a cancer-causing chemical may result in cancer if the chemical happens to alter cellular functions in a way that causes cancer to develop. Thus, even very low exposures to carcinogens might increase the risk of cancer, if only by a very small amount.

Several factors make it difficult to estimate the risk of cancer. Cancer appears to be a progressive disease because a series of cellular transformations is thought to occur before cancer develops. In addition, cancer in humans often develops many years after exposure to a chemical. Also, the best information available on the ability of chemicals to cause cancer often comes from studies in which a limited number of laboratory animals are exposed to levels of chemicals that are much higher than the levels humans would normally be exposed to in the environment. As a result, scientists use mathematical models based on studies of animals exposed to high levels of a chemical to estimate the probability of cancer developing in a diverse population of humans exposed to much lower levels. The uncertainty in these estimates may be rather large. To reduce these uncertainties, risk assessors must stay informed of new scientific research. Data from new studies can be used to improve estimates of cancer risks.

Non-Cancer Effects

Non-cancer health effects (such as asthma, nervous system disorders, birth defects, and developmental problems in children) typically become more severe as exposure to a chemical increases. One goal of dose-response assessment is to estimate levels of exposure that pose only a low or negligible risk for non-cancer health effects. Scientists analyze studies of the health effects of a chemical to develop this estimate. They take into account such factors as the quality of the scientific studies, whether humans or laboratory animals were studied, and the degree to which some people may be more sensitive to the chemical than others. The estimated level of exposure that poses no significant health risks can be reduced to reflect these factors.

Risk Characterization

The last step in risk assessment brings together the information developed in the previous three steps to estimate the risk of health effects in an exposed population. In the risk characterization step, scientists analyze the information developed during the exposure and dose-response assessments to describe the resulting health risks that are expected to occur in the exposed population. This information is presented in different ways for cancer and non-cancer health effects, as explained below.

Cancer Risk

Cancer risk is often expressed as the maximum number of new cases of cancer projected to occur in a population of one million people due to exposure to the cancer-causing substance over a 70-year lifetime. For example, a cancer risk of one in one million means that in a population of one million people, not more than one additional person would be expected to develop cancer as the result of the exposure to the substance causing that risk.

An individual's actual risk of contracting cancer from exposure to a chemical is often less than the theoretical risk to the entire population calculated in the risk assessment. For example, the risk estimate for a drinking-water contaminant may be based on the health-protective assumption that the individual drinks two liters of water from a contaminated source daily over a 70-year lifetime. However, an individual's actual exposure to that contaminant would likely be lower due to a shorter time of residence in the area. Moreover, an individual's risk not only depends on the individual's exposure to a specific chemical but also on his or her genetic background (i.e., a family history of certain types of cancer); health; diet; and lifestyle choices, such as smoking or alcohol consumption.

Cancer risks presented in risk assessments are often compared to the overall risk of cancer in the general U.S. population (about 250,000 cases for every one million people) or to the risk posed by all harmful chemicals in a particular medium, such as the air. The cancer risk from breathing current levels of pollutants in California's ambient air over a 70-year lifetime is estimated to be 760 in one million.

Non-Cancer Risk

Non-cancer risk is usually determined by comparing the actual level of exposure to a chemical to the level of exposure that is not expected to cause any adverse effects, even in the most susceptible people. Levels of exposure at which no adverse health effects are expected are called "health reference levels," and they generally are based on the results of animal studies. However, scientists usually set health reference levels much lower than the levels of exposure that were found to have no adverse effects in the animals tested. This approach helps to ensure that real health risks are not underestimated by adjusting for possible differences in a chemical's effects on laboratory animals and humans; the possibility that some humans, such as children and the elderly, may be particularly sensitive to a chemical; and possible deficiencies in data from the animal studies.

Depending on the amount of uncertainty in the data, scientists may set a health reference level 100 to 10,000 times lower than the levels of exposure observed to have no adverse effects in animal studies. Exposures above the health reference level are not necessarily hazardous, but the risk of toxic effects increases as the dose increases. If an assessment determines that human exposure to a chemical exceeds the health reference level, further investigation is warranted.

Risk managers rely on risk assessments when making regulatory decisions, such as setting drinking water standards, or developing plans to clean up hazardous waste sites. Risk managers are responsible for protecting human health, but they must also consider public acceptance, as well as technological, economic, social, and political factors, when arriving at their decisions. For example, they may need to consider how much it would cost to remove a contaminant from drinking water supplies or how seriously the loss of jobs would affect a community if a factory were to close due to the challenge of meeting regulatory requirements that are set at the most stringent level.

Health risk assessments can help risk managers weigh the benefits and costs of various alternatives for reducing exposure to chemicals. For example, a health risk assessment of a hazardous waste site could help determine whether placing a clay cap over the waste to prevent exposure would offer the same health protection as the more costly option of removing the waste from the site.

One of the most difficult questions of risk management is: How much risk is acceptable? While it would be ideal to completely eliminate all exposure to hazardous chemicals, it is usually not possible or feasible to remove all traces of a chemical once it has been released into the environment. The goal of most regulators is to reduce the health risks associated with exposure to hazardous pollutants to a negligibly low level.

Regulators generally presume that a one-in-one million risk of cancer from life-long exposure to a hazardous chemical is an “acceptable risk” level because the risk is extremely low compared to the overall cancer rate. If a drinking water standard for a cancer-causing chemical were set at the level posing a “one-in-one million” risk, it would mean that not more than one additional cancer case (beyond what would normally occur in the population) would potentially occur in a population of one million people drinking water meeting that standard over a 70-year lifetime.

Actual regulatory standards for chemicals or hazardous waste cleanups may be set at less stringent risk levels, such as one in 100,000 (not more than one additional cancer case per 100,000 people) or one in 10,000 (not more than one additional cancer case per 10,000 people). These less stringent risk levels are often due to economic or technological considerations. Regulatory agencies generally view these higher risk levels to be acceptable if there is no feasible way to reduce the risks further.”[1]

The following tables summarize the results of the HRA performed by the proposed OGS facility.

TABLE 5.1D-1
Criteria and Air Toxic Pollutants Emitted from OGS Facility

NOx	Propylene Oxide
CO	Toluene
VOC*	Xylene
SOx	Arsenic
PM10/PM2.5	Aluminum
Ammonia	Cadmium
PAHs	Chromium VI
Acetaldehyde	Copper

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[1] A Guide to Health Risk Assessment, CalEPA-Office of Environmental Health Hazard Assessment, 1001 I Street, Sacramento, Ca. 95812, (est. 2001).

TABLE 5.1D-1
Criteria and Air Toxic Pollutants Emitted from OGS Facility

Acrolein	Iron
Benzene	Lead
1-3 Butadiene	Mercury
Ethylbenzene	Manganese
Formaldehyde	Nickel
Hexane (n-Hexane)	Silver
Naphthalene	Zinc
Propylene	Diesel PM

TABLE 5.1D-2
Health Effects Significance Threshold Levels

	Significance Thresholds	
Agency	BAAQMD	State of California
Cancer Risk per million	<= 1.0 without T-BACT <= 10.0 with T-BACT	<= 1.0 without T-BACT <= 10.0 with T-BACT
Acute HI	1.0	1.0
Chronic HI	1.0	1.0
Cancer Burden	n/a	1.0

The other assumptions used in running the HARP program were as follows:

- Emission rates for non-criteria pollutants are taken from AFC Section 5.1, and from Appendix 5.1A. HAPs emissions factors are uncontrolled values, i.e., no control reductions were assumed as a result of the CO catalyst application.
- Number of residents affected is based upon the updated 2000 population data for those census tracts or portions of census tracts which lie within the maximum impact receptor radius of the proposed facility.
- All receptors were treated as residential receptors, which allows for the assumption that the MIR, if assumed residential, will represent the highest risk and no other receptor will show risks higher than the MIR. This deletes the need for running worker risks. The HARP risk run options as recommended by South Coast AQMD (Chico, 10-20-05) were utilized (i.e., for cancer – 70-year and derived adjusted method; for chronic – 70-year and derived OEHHA method; for acute – no options).
- Deposition velocity is taken to be 0.02 m/s, as recommended by ARB for controlled emission sources.
- Fraction of residents with gardens is taken to be 0.05 which is likely conservatively high for the urban area near the project site.
- Fraction of produce grown at home is taken to be 0.05, which is also likely to be conservatively high.

The HARP program is a tool that assists with the programmatic requirements of the Air Toxics Hot Spots Program, and it can be used for preparing health risk assessments for other related programs such as air toxic control measure development or facility permitting applications. HARP is a computer based risk assessment program which combines the tools of emission inventory database, facility prioritization, air dispersion modeling, and risk assessment analysis. Use of HARP promotes statewide consistency in the area of risk assessment, increases the efficiency of evaluating potential health impacts, and provides a cost effective tool for developing facility health risk assessments. HARP may be used on single sources, facilities with multiple sources, or multiple facilities in close proximity to each other.

The receptor grid used in HARP was a combination of the following:

- All identified grid receptors as input from the AERMOD analysis,
- All identified sensitive receptors within the primary impact area as defined by the AERMOD analysis.

The HARP program results for acute and chronic inhalation and chronic non-inhalation exposures, cancer burden and individual cancer risk (workplace and residential) for the combustion source and cooling tower are included in the CD with this Appendix. The results of the HARP calculations are summarized below.

The modeling results show that the maximum modeled cancer risk from OGS is expected to be 3.50 x E^{-6}. This risk is well below the BAAQMD significance value of 10 per million with T-BACT. T-BACT for combined cycle combustion turbines is the use of clean fuels (natural gas) and the operation of a CO catalyst. These T-BACT technologies are proposed for OGS, and as such, the significant risk threshold for OGS is 10 in a million. The chronic and acute non-cancer hazard indices are 0.021 and 0.0586, respectively at the cancer MIR. Both are well below the significant impact level of 1.0. Detailed calculations and results for each significant receptor are included in the modeling results, which are being submitted electronically.

TABLE 5.1D-3
Health Risk Assessment Summary

Turbines/HRSGs, Aux Boiler, Fire Pump Engine and Cooling Tower		
Risk Category	**Facility Values**	**Applicable Significance Thresholds***
Cancer Risk	3.50 x 10^{-6}	TBACT required if cancer risk is >1x10^{-6} and/or chronic HI is >0.2. Project risk cannot exceed a cancer risk of 1x10^{-5} and a chronic or acute HI of 1.0.
Chronic Hazard Index	0.021	
Acute Hazard Index at Cancer MIR	0.0586	
Acute Hazard Index at Max Acute Receptor	0.0807	

Cancer and chronic MIR – Receptor 12088, 610600mE, 4207100mN

Max Acute MIR – Receptor 7204, 610460mE, 4207160mN

*Per Regulation 2, Rule 5, Sections 301 and 302

The calculated health effects as summarized above do not exceed the district significance threshold values, therefore the health effects would be considered "not significant" and may even be "zero".

The following tables and figures are presented at the end of this appendix:

- Table 5.1D-4 Census Tract Numbers, Areas, and Population Data

Table 5.1D-5	BAAQMD TAC Summary
Table 5.1D-6	Sensitive Receptor Listing for the Primary Impact Radius
Table 5.1D-7	OEHHA/CARB Risk Assessment Health Values
Figure 5.1D-1	Sensitive Receptor Map
Figure 5.1D-2	Census Tracts in the Immediate Impact Area
Figure 5.1D-3	MIR-1, -2, -3 Location Map

Risk Assessment input and output files are included on the modeling CD. Due to the length of the HRA input and output files, hard copies are not provided in this appendix.

Construction HRA

A construction screening HRA was performed using the following assumptions as follows:

- The three highest construction offsite MIR receptors were chosen based upon the construction modeling as delineated in Appendix 5.1B.
- Cancer risk and chronic hazard indices were computed using the screening methodology as outlined in the South Coast AQMD (Health Risk Assessment Guidance for Analyzing Cancer Risks from Mobile Source Diesel Emissions, December 2002, and HRA guidance for Analyzing Cancer Risks from Mobile Source Diesel Idling Emissions for CEQA Air Quality Analysis, August 2003).
- A cancer inhalation unit risk value of 0.0003 (ug/m^3)$^{-1}$ was used.
- A cancer chronic inhalation REL of 5.0 (ug/m^3)$^{-1}$ was used.
- No acute inhalation REL exists for diesel PM.

The adjustment factor applied to the final risk and hazard index values was based upon a construction work schedule of 10 hrs/day, 5 days/week, 50 weeks/year, for 33 months (2.75 yrs),i.e., LEA value of 0.0112.

With respect to emissions from diesel fueled engines, use of the diesel PM exposure factors noted above are approved by CARB for the characterization of diesel engine exhaust and subsequent risk exposures. The diesel PM factor includes the range of fuel bound, and potentially emitted metals, PAHs, and a wide variety of other semi-volatile substances.

CARB notes the following in Appendix K of the current HARP Users Manual:

- The surrogate for whole diesel exhaust is diesel PM. PM10 is the basis for the potential risk calculations.
- When conducting an HRA, the potential cancer risk from inhalation exposure to diesel PM will outweigh the potential non-cancer health effects.
- When comparing whole diesel exhaust to speciated diesel exhaust, potential cancer risk from inhalation exposure to whole diesel exhaust will outweigh the multi-pathway cancer risk from the speciated compounds. For this reason, there will be few situations where an analysis of multi-pathway risk is necessary.

With respect to diesel particulate related risk values, the following should be noted:

> The US Department of Energy (DOE) as well as the US Environmental Protection Agency (EPA) have disagreed with the CARB/OEHHA and South Coast AQMD positions on the relative threat and relative contribution of diesel exhaust to "toxic" air pollution, and neither of the agencies, including the EPA's prestigious Health Effects Institute identify diesel exhaust as a "known" carcinogen, since the scientific studies show only "weak" cancer links. EPA and DOE believe that the studies relied upon by CARB and SCAQMD are flawed in that they use a problematic elemental carbon surrogate for ambient diesel particulate matter and ignored a significant portion of PM2.5 captured at the SCAQMD's own monitoring stations. In view of these conflicting studies, we suggest that caution be used in the decision making process regarding diesel PM and its associated risks, i.e., the actual risks may be much lower than those calculated by screening method herein. For these reasons, the risk table below reports the construction risk values using DPM only, and the inhalation pathway.

The following table presents the results of the screening level assessment of health risks from the construction phase.

TABLE 5.1D-4
Construction Screening Health Risk Assessment Summary

Construction Screening HRA Summary

MIR # and Receptor #	Annual Conc. ug/m^3	UTM E	UTM N	Cancer Risk	Chronic HI
1/5133	0.2962	610230	4207380	9.952E-7	0.000663
2/5128	0.2941	610230	4207330	9.882E-7	0.000659
3/5224	0.2865	610240	4207380	9.626E-7	0.000642

Table 5.1D-4

CENSUS FINDINGS

Map ID	Tract Number	Total Population	Population in Radius	Total Area(sq.mi.)	Area in Radius(sq.mi.)
T1	3010.00	3355	933.2	46.58	12.96
T2	3090.00	2496	472.8	7.27	1.38
T3	3020.03	10231	10231.0	6.96	6.96
T4	3050.00	6480	6434.9	3.67	3.64
T5	3060.02	3208	3208.0	3.65	3.65
T6	3120.00	2617	241.6	0.56	0.05
T7	3020.02	8475	7726.8	9.23	8.41
T8	3060.01	8166	8166.0	1.36	1.36
T9	3131.02	3922	187.5	0.76	0.04
T10	3071.02	5018	5018.0	0.62	0.62
T11	3072.01	3029	3023.8	0.58	0.58
T12	3072.02	4493	4493.0	0.27	0.27
T13	3072.05	7162	7162.0	1.18	1.18
T14	3080.01	7552	7552.0	1.44	1.44
T15	3072.04	4443	4443.0	0.58	0.58
T16	3080.02	4206	4206.0	1.54	1.54
T17	3131.03	5912	226.3	5.40	0.21
T18	3020.04	10906	10906.0	4.66	4.66
T19	3071.01	4443	4443.0	0.82	0.82
T20	3551.06	10572	2460.4	39.90	9.29
T21	3551.01	15237	15237.0	2.79	2.79
T22	3040.00	10882	44.9	71.38	0.29
T23	3031.00	8321	3323.2	15.48	6.18
T24	3032.00	21608	13574.1	15.06	9.46
T25	0098.00	1934	861.7	60.25	26.85
T26	2535.00	5733	178.5	235.10	7.32

Table 5.1D-5

San Francisco Bay Area Air Basin

Annual Average Concentrations and Health Risks

Annual Average Concentrations and Health Risks																			
[illegible]	Conc./Risk[2]	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Acetaldehyde	Annual Avg	1.3	1.4	1.03	1.31	1.17	0.42	0.83	0.73	0.65	0.76	0.68	0.79	[illegible]	0.74	0.74	0.71	0.66	0.56
	Health Risk	6	7	5	6	6	2	4	4	3	4	3	4	3	4	4	3	3	3
Benzene	Annual Avg	2.18	1.82	1.49	1.49	1.4	1.26	0.71	0.61	0.71	[illegible]	[illegible]	0.425	[illegible]	0.439	0.372	[illegible]	[illegible]	[illegible]
	Health Risk	202	169	138	138	129	116	66	56	66	55	52	39	42	41	34	29	30	25
1,3-Butadiene	Annual Avg	0.359	0.287	0.275	[illegible]	0.287	0.277	0.218	0.187	[illegible]	0.17	0.149	0.133	0.137	0.098	0.09	0.075	0.069	0.06
	Health Risk	135	108	103	138	108	104	82	70	82	64	56	50	51	37	34	28	26	23
Carbon Tetrachloride	Annual Avg	0.128	0.125		0.108		0.1	0.078				0.094	0.087	0.089	[illegible]				
	Health Risk	34	33		29		26	21				25	23	24	25				
Chromium, Hexavalent	Annual Avg			0.23	0.2	0.19	0.25	0.13	0.12	0.1	0.1	0.12		0.074	[illegible]	[illegible]	[illegible]	0.063	0.053
	Health Risk			34	29	29	37	19	17	15	15	18		11	14	14	12	9	8
para-Dichlorobenzene	Annual Avg		0.12	0.12	0.12	0.11	0.13	[illegible]	0.12			0.11	0.14	0.15	0.15	[illegible]	0.15	0.15	
	Health Risk		8	8	8	7	8	9	8			7	9	10	10	11	10	10	
Formaldehyde	Annual Avg	1.87	[illegible]	1.43	1.56	1.66	2.06	2.62	1.85	[illegible]	2.09	1.77	2.32	[illegible]	2.22	[illegible]	1.32	[illegible]	1.45
	Health Risk	14	13	11	11	12	15	19	14	13	15	13	17	19	16	13	10	12	11
Methylene Chloride	Annual Avg	1.04	2.32	0.65	[illegible]	0.69	0.6	0.58	0.55			0.53	0.27	0.22	0.22	[illegible]	[illegible]	[illegible]	0.13
	Health Risk	4	8	2	2	2	2	2	2			2	<1	<1	<1	<1	<1	<1	<1
Perchloroethylene	Annual Avg	0.204	0.232	[illegible]	0.128	0.082	0.094	[illegible]	0.071			0.078	0.059	[illegible]	[illegible]	[illegible]	0.029	[illegible]	0.031
	Health Risk	8	9	7	5	3	4	3	3			3	2	2	2	1	1	1	1
Diesel PM[3]	*Annual Avg*	*(2.5)*					*(1.9)*					*(1.6)*							
	Health Risk	*(750)*					*(570)*					*(480)*							
Average Basin Risk	w/o Diesel PM	[illegible]	355	308	[illegible]	[illegible]	314	225	174	179	[illegible]	179	[illegible]	162	149	[illegible]	[illegible]	[illegible]	[illegible]
	w/ Diesel PM	*(1153)*					*[illegible]*					*(659)*							

1 Concentrations for Hexavalent chromium are expressed as ng/m3 and concentrations for diesel PM are expressed as ug/m3. Concentrations for all other TACs are expressed as parts per billion.

2 Health Risk represents the number of excess cancer cases per million people based on a lifetime (70-year) exposure to the annual average concentration. It reflects only those compounds listed in this table and only those with data for that year. There may be other significant compounds for which we do not monitor or have health risk information. Additional information about interpreting the toxic air contaminant air quality trends can be found in Chapter 1, *Interpreting the Emission and Air Quality Statistics*.

3 Diesel PM estimates are based on receptor modeling techniques, and the estimates are available only for selected years. Currently, the estimates are being reviewed.

Table 5-44

Table 5.1D-6 Identified Sensitive Receptors and Distances from Site

Contra Costa Generating Station

	Google Earth Data			Dist. From Site, m.	Dist. From Site, ft.	Receptor #	**NAD27**		
Receptor ID	UTM Em	UTM Nm	Elev., ft.				**UTM Em**	**UTM Nm**	**Elev, ft.**
Site	**609908**	**4207669**	21	na	na		610007	4207486	24
School	612505	4207053	17	2669.1	8757.2	1	612604	4206870	20
School	613136	4205251	42	4033.2	13232.9	2	613235	4205068	45
School	614245	4203981	49	5693.1	18678.9	3	614344	4203798	52
School	611969	4203762	91	4417.3	14493.1	4	612068	4203579	94
School	612787	4203104	88	5397.0	17707.6	5	612886	4202921	91
School	607091	4206999	58	2895.6	9500.4	6	607190	4206816	61
School	608217	4204875	164	3265.9	10715.3	7	608316	4204692	167
School	609587	4202969	159	4710.9	15456.6	8	609686	4202786	162
School	608284	4203071	169	4876.4	15999.4	9	608383	4202888	172
School	607716	4203318	179	4872.0	15984.9	10	607815	4203135	182
School	607389	4203010	238	5296.4	17377.4	11	607488	4202827	241
School	605534	4202978	187	6413.8	21043.8	12	605633	4202795	190
School	604151	4205710	79	6081.2	19952.3	13	604250	4205527	82
School	603855	4207114	36	6078.4	19943.2	14	603954	4206931	39
School	603579	4207607	28	6329.3	20766.4	15	603678	4207424	31
School	604042	4208016	26	5876.3	19280.0	16	604141	4207833	29
School	603860	4208336	11	6084.7	19963.8	17	603959	4208153	14
Hospital	604875	4204531	142	5931.1	19460.0	18	604974	4204348	145
School	617677	4203118	24	9003.8	29541.6	19	617776	4202935	27
Hospital	607320	4201797	205	6417.0	21054.2	20	607419	4201614	208
Res-1	611104	4207838	8	1207.9	3963.1	21	611203	4207655	11
Res-2	610839	4207573	17	935.9	3070.8	22	610938	4207390	20
Worker	610224	4207747	20	325.5	1067.9	23	610323	4207564	23

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

		Noncancer Effects								Cancer Risk					
Substance	Chemical▼ Abstract Number	Acute Inhalation $(\mu g/m^3)$	Date ◆ Value Reviewed [Added]	8-Hour Inhalation $(\mu g/m^3)$	Date ◆ Value Reviewed [Added]	Chronic Inhalation $(\mu g/m^3)$	Date ◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date ◆ Value Reviewed [Added]	Inhalation * Unit Risk $(\mu g/m^3)^{-1}$	Inhalation * Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Date ◆ Value Reviewed [Added]	Oral Slope Factor $(mg/kg\text{-}d)^{-1}$	Date ◆ Value Reviewed [Added]	M♣ W A F
ACETALDEHYDE	75-07-0	4.7E+02	12/08	3.0E+02	12/08	1.4E+02	12/08			2.7E-06	1.0E-02	4/99 [5/93]			1
ACETAMIDE	60-35-5									2.0E-05	7.0E-02	4/99			1
ACROLEIN	107-02-8	2.5E+00	12/08	7.0E-01	12/08	3.5E-01	12/08								1
ACRYLAMIDE	79-06-1									1.3E-03	4.5E+00	4/99 [7/90]			1
ACRYLIC ACID	79-10-7	6.0E+03	4/99												1
ACRYLONITRILE	107-13-1					5.0E+00	12/01			2.9E-04	1.0E+00	4/99 [1/91]			1
ALLYL CHLORIDE	107-05-1									6.0E-06	2.1E-02	4/99			1
2-AMINOANTHRAQUINONE	117-79-3									9.4E-06	3.3E-02	4/99			1
AMMONIA	7664-41-7	3.2E+03	4/99			2.0E+02	2/00								1
ANILINE	62-53-3									1.6E-06	5.7E-03	4/99			1
ARSENIC AND COMPOUNDS (INORGANIC)^{TAC}	7440-38-2 1016 [1015]	2.0E-01	12/08	1.5E-02	12/08	1.5E-02	12/08	3.5E-06	12/08	3.3E-03 TAC	1.2E+01	7/90	1.5E+00	10/00	1
ARSINE	7784-42-1	2.0E-01	12/08	1.5E-02	12/08	1.5E-02	12/08								1
ASBESTOS^{TAC} ¤	1332-21-4									1.9E-04 TAC ¤	2.2E+02	3/86			333.33
BENZENE^{TAC}	71-43-2	1.3E+03	4/99			6.0E+01	2/00			2.9E-05^{TAC}	1.0E-01	1/85			1
BENZIDINE (AND ITS SALTS) *values also apply to:*	92-87-5									1.4E-01	5.0E+02	4/99 [1/91]			1
Benzidine based dyes	*1020*									*1.4E-01*	*5.0E+02*	*4/99* *[1/91]*			*1*
Direct Black 38	*1937-37-7*									*1.4E-01*	*5.0E+02*	*4/99* *[1/91]*			*1*
Direct Blue 6	*2602-46-2*									*1.4E-01*	*5.0E+02*	*4/99* *[1/91]*			*1*
Direct Brown 95 (technical grade)	*16071-86-6*									*1.4E-01*	*5.0E+02*	*4/99* *[1/91]*			*1*
BENZYL CHLORIDE	100-44-7	2.4E+02	4/99							4.9E-05	1.7E-01	4/99			1
BERYLLIUM AND COMPOUNDS	7440-41-7 [1021]					7.0E-03	12/01	2.0E-03	12/01	2.4E-03	8.4E+00	4/99 [7/90]			1
BIS(2-CHLOROETHYL)ETHER (Dichloroethyl ether)	111-44-4									7.1E-04	2.5E+00	4/99			1
BIS(CHLOROMETHYL)ETHER	542-88-1									1.3E-02	4.6E+01	4/99 [1/91]			1
BROMINE AND COMPOUNDS	7726-95-6 [1040]														1
POTASSIUM BROMATE	7758-01-2									1.4E-04	4.9E-01	4/99 [10/93]			1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date◆ Value Reviewed [Added]	Inhalation* Unit Risk (µg/m^3)$^{-1}$	Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	M♣ W A F
1,3-BUTADIENE^{TAC}	106-99-0					2.0E+01	1/01			1.7E-04 TAC	6.0E-01	7/92			1
CADMIUM AND COMPOUNDS^{TAC}	7440-43-9 [1045]					2.0E-02	1/01	5.0E-04	10/00	4.2E-03 TAC	1.5E+01	1/87			1
CARBON DISULFIDE	75-15-0	6.2E+03	4/99			8.0E+02	5/02								1
CARBON MONOXIDE	630-08-0	2.3E+04	4/99												1
CARBON TETRACHLORIDE^{TAC} (Tetrachloromethane)	56-23-5	1.9E+03	4/99			4.0E+01	1/01			4.2E-05 TAC	1.5E-01	9/87			1
CHLORINATED PARAFFINS	108171-26-2									2.5E-05	8.9E-02	4/99			1
CHLORINE	7782-50-5	2.1E+02	4/99			2.0E-01	2/00								1
CHLORINE DIOXIDE	10049-04-4					6.0E-01	1/01								1
4-CHLORO-O-PHENYLENEDIAMINE	95-83-0									4.6E-06	1.6E-02	4/99			1
CHLOROBENZENE	108-90-7					1.0E+03	1/01								1
CHLORODIFLUOROMETHANE ... (see Fluorocarbons)															
CHLOROFORM^{TAC}	67-66-3	1.5E+02	4/99			3.0E+02	4/00			5.3E-06 TAC	1.9E-02	12/90			1
Chlorophenols	*1060*														*1*
PENTACHLOROPHENOL	87-86-5									5.1E-06	1.8E-02	4/99			1
2,4,6-TRICHLOROPHENOL	88-06-2									2.0E-05	7.0E-02	4/99 [1/91]			1
CHLOROPICRIN	76-06-2	2.9E+01	4/99			4.0E-01	12/01								1
p-CHLORO-o-TOLUIDINE	95-69-2									7.7E-05	2.7E-01	4/99			1
CHROMIUM 6+^{TAC} *values also apply to:*	18540-29-9					2.0E-01	1/01	2.0E-02	10/00	1.5E-01 TAC	5.1E+02	1/86	Ø		1
Barium chromate	*10294-40-3*					*2.0E-01*	*1/01*	*2.0E-02*	*10/00*	*1.5E-01* *TAC*	*5.1E+02*	*1/86*	Ø		*0.2053*
Calcium chromate	*13765-19-0*					*2.0E-01*	*1/01*	*2.0E-02*	*10/00*	*1.5E-01* *TAC*	*5.1E+02*	*1/86*	Ø		*0.3332*
Lead chromate	*7758-97-6*					*2.0E-01*	*1/01*	*2.0E-02*	*10/00*	*1.5E-01* *TAC*	*5.1E+02*	*1/86*	Ø		*0.1609*
Sodium dichromate	*10588-01-9*					*2.0E-01*	*1/01*	*2.0E-02*	*10/00*	*1.5E-01* *TAC*	*5.1E+02*	*1/86*	Ø		*0.397*
Strontium chromate	*7789-06-2*					*2.0E-01*	*1/01*	*2.0E-02*	*10/00*	*1.5E-01* *TAC*	*5.1E+02*	*1/86*	Ø		*0.2554*
CHROMIUM TRIOXIDE (as chromic acid mist)	1333-82-0					2.0E-03	1/01	2.0E-02	10/00	1.5E-01 TAC	5.1E+02	1/86	Ø		0.52
COPPER AND COMPOUNDS	7440-50-8 [1067]	1.0E+02	4/99												1
p-CRESIDINE	120-71-8									4.3E-05	1.5E-01	4/99			1
CRESOLS (mixtures of)	1319-77-3					6.0E+02	1/01								1
m-CRESOL	108-39-4					6.0E+02	1/01								1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

		Noncancer Effects								Cancer Risk					
Substance	**Chemical Abstract Number**▼	**Acute Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**8-Hour Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**Chronic Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**Chronic Oral (mg/kg-d)**	**Date◆ Value Reviewed [Added]**	**Inhalation Unit Risk ($\mu g/m^3$)$^{-1}$** *	**Inhalation Cancer Potency Factor (mg/kg-d)$^{-1}$** *	**Date◆ Value Reviewed [Added]**	**Oral Slope Factor (mg/kg-d)$^{-1}$**	**Date◆ Value Reviewed [Added]**	**MWAF**♣
o-CRESOL	95-48-7					6.0E+02	1/01								1
p-CRESOL	106-44-5					6.0E+02	1/01								1
CUPFERRON	135-20-6									6.3E-05	2.2E-01	4/99			1
Cyanide Compounds (inorganic)	*57-12-5* *1073*	*3.4E+02*	*4/99*			*9.0E+00*	*4/00*								*1*
HYDROGEN CYANIDE (Hydrocyanic acid)	74-90-8	3.4E+02	4/99			9.0E+00	4/00								1
2,4-DIAMINOANISOLE	615-05-4									6.6E-06	2.3E-02	4/99			1
2,4-DIAMINOTOLUENE	95-80-7									1.1E-03	4.0E+00	4/99			1
1,2-DIBROMO-3-CHLOROPROPANE (DBCP)	96-12-8									2.0E-03	7.0E+00	4/99 [1/92]			1
p-DICHLOROBENZENE	106-46-7					8.0E+02	1/01			1.1E-05	4.0E-02	4/99 [1/91]			1
3,3-DICHLOROBENZIDINE	91-94-1									3.4E-04	1.2E+00	4/99 [1/91]			1
1,1,-DICHLOROETHANE (Ethylidene dichloride)	75-34-3									1.6E-06	5.7E-03	4/99			1
1,1-DICHLOROETHYLENE … (see Vinylidene Chloride)															
DI(2-ETHYLHEXYL)PHTHALATE (DEHP)	117-81-7									2.4E-06	8.4E-03	4/99 [1/92]	8.4E-03	10/00	1
DIESEL EXHAUST … (see Particulate Emissions from Diesel-Fueled Engines)															
DIETHANOLAMINE	111-42-2					3.0E+00	12/01								
p-DIMETHYLAMINOAZOBENZENE	60-11-7									1.3E-03	4.6E+00	4/99			1
N,N-DIMETHYL FORMAMIDE	68-12-2					8.0E+01	1/01								1
2,4-DINITROTOLUENE	121-14-2									8.9E-05	3.1E-01	4/99			1
1,4-DIOXANE[†] (1,4-Diethylene dioxide)	123-91-1	3.0E+03	4/99			3.0E+03	4/00			7.7E-06	2.7E-02	4/99 [1/91]			1
EPICHLOROHYDRIN (1-Chloro-2,3-epoxypropane)	106-89-8	1.3E+03	4/99			3.0E+00	1/01			2.3E-05	8.0E-02	4/99 [1/92]			1
1,2-EPOXYBUTANE	106-88-7					2.0E+01	1/01								1
ETHYL BENZENE	100-41-4					2.0E+03	2/00			2.5E-06	8.7E-3	11/07			1
ETHYL CHLORIDE (Chloroethane)	75-00-3					3.0E+04	4/00								1
ETHYLENE DIBROMIDE[TAC] (1,2-Dibromoethane)	106-93-4					8.0E-01	12/01			7.1E-05 TAC	2.5E-01	7/85			1
ETHYLENE DICHLORIDE[TAC] (1,2-Dichloroethane)	107-06-2					4.0E+02	1/01			2.1E-05 TAC	7.2E-02	9/85			1
ETHYLENE GLYCOL	107-21-1					4.0E+02	4/00								1
ETHYLENE GLYCOL BUTYL ETHER … (see Glycol ethers)															

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

		Noncancer Effects								Cancer Risk					
Substance	**Chemical▼ Abstract Number**	**Acute Inhalation (μg/m^3)**	**Date◆ Value Reviewed [Added]**	**8-Hour Inhalation (μg/m^3)**	**Date◆ Value Reviewed [Added]**	**Chronic Inhalation (μg/m^3)**	**Date◆ Value Reviewed [Added]**	**Chronic Oral (mg/kg-d)**	**Date◆ Value Reviewed [Added]**	**Inhalation* Unit Risk (μg/m^3)$^{-1}$**	**Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$**	**Date◆ Value Reviewed [Added]**	**Oral Slope Factor (mg/kg-d)$^{-1}$**	**Date◆ Value Reviewed [Added]**	**M♣ W A F**
ETHYLENE OXIDE$^{\text{TAC}}$ (1,2-Epoxyethane)	75-21-8					3.0E+01	1/01			8.8E-05 TAC	3.1E-01	11/87			1
ETHYLENE THIOUREA	96-45-7									1.3E-05	4.5E-02	4/99			1
Fluorides	1101	*2.4E+02*	*4/99*			1.3E+01	8/03	4.0E-02	8/03						*1*
HYDROGEN FLUORIDE (Hydrofluoric acid)	7664-39-3	2.4E+02	4/99			1.4E+01	8/03	4.0E-02	8/03						1
FORMALDEHYDE$^{\text{TAC}}$	50-00-0	5.5E+01	12/08	9.0E+00	12/08	9.0E+00	12/08			6.0E-06 TAC	2.1E-02	3/92			1
GLUTARALDEHYDE	111-30-8					8.0E-02	1/01								1
GLYCOL ETHERS	1115														1
ETHYLENE GLYCOL BUTYL ETHER – EGBE	111-76-2	1.4E+04	4/99												1
ETHYLENE GLYCOL ETHYL ETHER – EGEE	110-80-5	3.7E+02	4/99[1/92]			7.0E+01	2/00								1
ETHYLENE GLYCOL ETHYL ETHER ACETATE – EGEEA	111-15-9	1.4E+02	4/99			3.0E+02	2/00								1
ETHYLENE GLYCOL METHYL ETHER – EGME	109-86-4	9.3E+01	4/99			6.0E+01	2/00								1
ETHYLENE GLYCOL METHYL ETHER ACETATE – EGMEA	110-49-6					9.0E+01	2/00								1
HEXACHLOROBENZENE	118-74-1									5.1E-04	1.8E+00	4/99 [1/91]			1
HEXACHLOROCYCLOHEXANES (mixed or technical grade)	608-73-1									1.1E-03	4.0E+00	4/99 [1/91]	4.0E+00	10/00 [1/92]	1
alpha-HEXACHLOROCYCLOHEXANE	319-84-6									1.1E-03	4.0E+00	4/99 [1/91]	4.0E+00	10/00 [1/92]	1
beta-HEXACHLOROCYCLOHEXANE	319-85-7									1.1E-03	4.0E+00	4/99 [1/91]	4.0E+00	10/00 [1/92]	1
gamma-HEXACHLOROCYCLOHEXANE (Lindane)	58-89-9									3.1E-04	1.1E+00	4/99	1.1E+00	10/00	1
n-HEXANE	110-54-3					7.0E+03	4/00								1
HYDRAZINE	302-01-2					2.0E-01	1/01			4.9E-03	1.7E+01	4/99 [7/90]			1
HYDROCHLORIC ACID (Hydrogen chloride)	7647-01-0	2.1E+03	4/99			9.0E+00	2/00								1
HYDROGEN BROMIDE … (see Bromine & Compounds)															
HYDROGEN CYANIDE … (see Cyanide & Compounds)															
HYDROGEN FLUORIDE … (see Fluorides & Compounds)															

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES∗

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date◆ Value Reviewed [Added]	Inhalation* Unit Risk (µg/m^3)$^{-1}$	Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	MWAF♣
HYDROGEN SELENIDE … (see Selenium & Compounds)															
HYDROGEN SULFIDE	7783-06-4	4.2E+01	4/99[7/90]			1.0E+01	4/00								1
ISOPHORONE	78-59-1					2.0E+03	12/01								
ISOPROPYL ALCOHOL (Isopropanol)	67-63-0	3.2E+03	4/99			7.0E+03	2/00								1
LEAD AND COMPOUNDS^{TAC} ♫✱ (inorganic) *values also apply to:*	7439-92-1 1128 [1130]									1.2E-05 TAC	4.2E-02	4/97	8.5E-03	10/00	1
Lead acetate	*301-04-2*									*1.2E-05* *TAC*	*4.2E-02*	*4/97*	*8.5E-03*	*10/00*	*0.637*
Lead phosphate	*7446-27-7*									*1.2E-05* *TAC*	*4.2E-02*	*4/97*	*8.5E-03*	*10/00*	*0.7659*
Lead subacetate	*1335-32-6*									*1.2E-05* *TAC*	*4.2E-02*	*4/97*	*8.5E-03*	*10/00*	*0.7696*
LINDANE ... (see gamma-Hexachlorocyclohexane)															
MALEIC ANHYDRIDE	108-31-6					7.0E-01	12/01								1
MANGANESE AND COMPOUNDS	7439-96-5 [1132]			1.7E-01	12/08	9.0E-02	12/08								1
MERCURY AND COMPOUNDS (INORGANIC)	7439-97-6 [1133]	6.0E-01	12/08	6.0E-02	12/08	3.0E-02	12/08	1.6E-04	12/08						1
Mercuric chloride	*7487-94-7*	*6.0E-01*	*12/08*	*6.0E-02*	*12/08*	*3.0E-02*	*12/08*	*1.6E-04*	*12/08*						*1*
METHANOL	67-56-1	2.8E+04	4/99			4.0E+03	4/00								1
METHYL BROMIDE (Bromomethane)	74-83-9	3.9E+03	4/99			5.0E+00	2/00								1
METHYL tertiary-BUTYL ETHER	1634-04-4					8.0E+03	2/00			2.6E-07	1.8E-03	11/99			1
METHYL CHLOROFORM (1,1,1-Trichloroethane)	71-55-6	6.8E+04	4/99			1.0E+03	2/00								1
METHYL ETHYL KETONE (2-Butanone)	78-93-3	1.3E+04	4/99												1
METHYL ISOCYANATE	624-83-9					1.0E+00	12/01								1
METHYL MERCURY ... (see Mercury & Compounds)															
4,4'-METHYLENE BIS (2-CHLOROANILINE) (MOCA)	101-14-4									4.3E-04	1.5E+00	4/99			1
METHYLENE CHLORIDE ^{TAC} (Dichloromethane)	75-09-2	1.4E+04	4/99			4.0E+02	2/00			1.0E-06 TAC	3.5E-03	7/89			1
4,4'-METHYLENE DIANILINE (AND ITS DICHLORIDE)	101-77-9					2.0E+01	12/01			4.6E-04	1.6E+00	4/99	1.6E+00	10/00	1
METHYLENE DIPHENYL ISOCYANATE	101-68-8					7.0E-01	1/01								1
MICHLER'S KETONE (4,4'-Bis(dimethylamino)benzophenone)	90-94-8									2.5E-04	8.6E-01	4/99			1
N-NITROSODI-n-BUTYLAMINE	924-16-3									3.1E-03	1.1E+01	4/99 [1/92]			1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date◆ Value Reviewed [Added]	Inhalation* Unit Risk (µg/m^3)$^{-1}$	Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	M♣ W A F
N-NITROSODI-n-PROPYLAMINE	621-64-7									2.0E-03	7.0E+00	4/99 [1/91]			1
N-NITROSODIETHYLAMINE	55-18-5									1.0E-02	3.6E+01	4/99 [1/91]			1
N-NITROSODIMETHYLAMINE	62-75-9									4.6E-03	1.6E+01	4/99 [1/91]			1
N-NITROSODIPHENYLAMINE	86-30-6									2.6E-06	9.0E-03	4/99			1
N-NITROSO-N-METHYLETHYLAMINE	10595-95-6									6.3E-03	2.2E+01	4/99 [7/90]			1
N-NITROSOMORPHOLINE	59-89-2									1.9E-03	6.7E+00	4/99 [7/92]			1
N-NITROSOPIPERIDINE	100-75-4									2.7E-03	9.4E+00	4/99 [7/92]			1
N-NITROSOPYRROLIDINE	930-55-2									6.0E-04	2.1E+00	4/99 [7/90]			1
NAPHTHALENE ... (see Polycyclic aromatic hydrocarbons)															
NICKEL AND COMPOUNDS^{TAC} *values also apply to:*	7440-02-0 [1145]	6.0E+00	4/99			5.0E-02	2/00	5.0E-02	10/00	2.6E-04 TAC	9.1E-01	8/91			1
Nickel acetate	*373-02-4*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.3321*
Nickel carbonate	*3333-67-3*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.4945*
Nickel carbonyl	*13463-39-3*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.3438*
Nickel hydroxide	*12054-48-7*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.6332*
Nickelocene	*1271-28-9*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.4937*
NICKEL OXIDE	1313-99-1	6.0E+00	4/99			1.0E-01	2/00	5.0E-02	10/00	2.6E-04 TAC	9.1E-01	8/91			0.7859
Nickel refinery dust from the pyrometallurgical process	*1146*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*1*
Nickel subsulfide	*12035-72-2*	*6.0E+00*	*4/99*			*5.0E-02*	*2/00*	*5.0E-02*	*10/00*	*2.6E-04* *TAC*	*9.1E-01*	*8/91*			*0.2443*
NITRIC ACID	7697-37-2	8.6E+01	4/99												1
NITROGEN DIOXIDE	10102-44-0	4.7E+02	4/99[1/92]												1
p-NITROSODIPHENYLAMINE	156-10-5									6.3E-06	2.2E-02	4/99			1
OZONE	10028-15-6	1.8E+02	4/99[1/92]												1
PARTICULATE EMISSIONS FROM DIESEL-FUELED ENGINES^{TAC} ■¶	9901					5.0E+00 TAC	8/98			3.0E-04 TAC	1.1E+00	8/98			1
PENTACHLOROPHENOL ... (see Chlorophenols)															

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^{3})	Date◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^{3})	Date◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^{3})	Date◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date◆ Value Reviewed [Added]	Inhalation* Unit Risk (µg/m^{3})$^{-1}$	Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	M♣ W A F
PERCHLOROETHYLENE^{TAC} (Tetrachloroethylene)	127-18-4	2.0E+04	4/99			3.5E+01 TAC	10/91			5.9E-06 TAC	2.1E-02	10/91			1
PHENOL	108-95-2	5.8E+03	4/99			2.0E+02	4/00								1
PHOSGENE	75-44-5	4.0E+00	4/99												1
PHOSPHINE	7803-51-2					8.0E-01	9/02								1
PHOSPHORIC ACID	7664-38-2					7.0E+00	2/00								1
PHTHALIC ANHYDRIDE	85-44-9					2.0E+01	1/01								1
PCB (POLYCHLORINATED BIPHENYLS) (unspeciated mixture) [lowest risk] ☼★	1336-36-3									2.0E-05	7.0E-02	4/99	7.0E-02	10/00	1
PCB (POLYCHLORINATED BIPHENYLS) (unspeciated mixture) [low risk] ☼★	1336-36-3									1.1E-04	4.0E-01★		4.0E-01★		1
PCB (POLYCHLORINATED BIPHENYLS) (unspeciated mixture) [high risk] ☼★	1336-36-3									5.7E-04	2.0E+00	4/99	2.0E+00	10/00	1
PCB (POLYCHLORINATED BIPHENYLS (speciated) ϖ															
3,3',4,4'-TETRACHLOROBIPHENYL (PCB 77)	32598-13-3					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
3,4,4',5-TETRACHLOROBIPHENYL (PCB 81)	70362-50-4					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
2,3,3',4,4'-PENTACHLOROBIPHENYL (PCB 105)	32598-14-4					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
2,3,4,4',5-PENTACHLOROBIPHENYL (PCB 114)	74472-37-0					8.0E-02	8/03	2.0E-05	8/03	1.9E-02	6.5E+01	8/03	6.5E+01	8/03	1
2,3',4,4',5-PENTACHLOROBIPHENYL (PCB 118)	31508-00-6					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
2,3',4,4',5'-PENTACHLOROBIPHENYL (PCB 123)	65510-44-3					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
3,3',4,4',5-PENTACHLOROBIPHENYL (PCB 126)	57465-28-8					4.0E-04	8/03	1.0E-07	8/03	3.8E+00	1.3E+04	8/03	1.3E+04	8/03	1
2,3,3',4,4',5-HEXACHLOROBIPHENYL (PCB 156)	38380-08-4					8.0E-02	8/03	2.0E-05	8/03	1.9E-02	6.5E+01	8/03	6.5E+01	8/03	1
2,3,3',4,4',5'-HEXACHLOROBIPHENYL (PCB 157)	69782-90-7					8.0E-02	8/03	2.0E-05	8/03	1.9E-02	6.5E+01	8/03	6.5E+01	8/03	1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES⁎

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date ◆ Value Reviewed [Added]	Inhalation * Unit Risk (µg/m^3)$^{-1}$	Inhalation * Cancer Potency Factor (mg/kg-d)$^{-1}$	Date ◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date ◆ Value Reviewed [Added]	M♣ W A F
2,3',4,4',5,5'-HEXACHLOROBIPHENYL (PCB 167)	52663-72-6					4.0E+00	8/03	1.0E-03	8/03	3.8E-04	1.3E+00	8/03	1.3E+00	8/03	1
3,3',4,4',5,5'-HEXACHLOROBIPHENYL (PCB 169)	32774-16-6					4.0E-03	8/03	1.0E-06	8/03	3.8E-01	1.3E+03	8/03	1.3E+03	8/03	1
2,3,3',4,4',5,5'-HEPTACHLOROBIPHENYL (PCB 189)	39635-31-9					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
POLYCHLORINATED DIBENZO-*P*-DIOXINS (PCDD) (Treated as 2,3,7,8-TCDD for HRA)$^{\text{TAC}}$ ●	1085 1086					4.0E-05	2/00	1.0E-08	10/00	3.8E+01 TAC	1.3E+05	8/86	1.3E+05 TAC	8/86	1
2,3,7,8-TETRACHLORODIBENZO-*P*-DIOXIN$^{\text{TAC}}$	1746-01-6					4.0E-05	2/00	1.0E-08	10/00	3.8E+01 TAC	1.3E+05	8/86	1.3E+05 TAC	8/86	1
1,2,3,7,8-PENTACHLORODIBENZO-*P*-DIOXIN	40321-76-4					4.0E-05	8/03	1.0E-08	8/03	3.8E+01	1.3E+05	8/03	1.3E+05	8/03	1
1,2,3,4,7,8-HEXACHLORODIBENZO-*P*-DIOXIN	39227-28-6					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,6,7,8-HEXACHLORODIBENZO-*P*-DIOXIN	57653-85-7					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,7,8,9-HEXACHLORODIBENZO-*P*-DIOXIN	19408-74-3					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,4,6,7,8-HEPTACHLORODIBENZO-*P*-DIOXIN	35822-46-9					4.0E-03	2/00	1.0E-06	10/00	3.8E-01	1.3E+03	4/99	1.3E+03	10/00	1
1,2,3,4,6,7,8,9-OCTACHLORODIBENZO-*P*-DIOXIN	3268-87-9					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
POLYCHLORINATED DIBENZOFURANS (PCDF) $^{\text{TAC}}$ ● (Treated as 2,3,7,8-TCDD for HRA)	1080					4.0E-05	2/00	1.0E-08	10/00	3.8E+01 TAC	1.3E+05	8/86	1.3E+05 TAC	8/86	1
2,3,7,8-TETRACHLORODIBENZOFURAN	5120-73-19					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,7,8-PENTACHLORODIBENZOFURAN	57117-41-6					8.0E-04	2/00	2.0E-07	10/00	1.9E+00	6.5E+03	4/99	6.5E+03	10/00	1
2,3,4,7,8-PENTACHLORODIBENZOFURAN	57117-31-4					8.0E-05	2/00	2.0E-08	10/00	1.9E+01	6.5E+04	4/99	6.5E+04	10/00	1
1,2,3,4,7,8-HEXACHLORODIBENZOFURAN	70648-26-9					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES❖

		Noncancer Effects								Cancer Risk					
Substance	**Chemical▼ Abstract Number**	**Acute Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**8-Hour Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**Chronic Inhalation ($\mu g/m^3$)**	**Date◆ Value Reviewed [Added]**	**Chronic Oral (mg/kg-d)**	**Date◆ Value Reviewed [Added]**	**Inhalation* Unit Risk $(\mu g/m^3)^{-1}$**	**Inhalation* Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$**	**Date◆ Value Reviewed [Added]**	**Oral Slope Factor $(mg/kg\text{-}d)^{-1}$**	**Date◆ Value Reviewed [Added]**	**M♣ W A F**
1,2,3,6,7,8-HEXACHLORODIBENZOFURAN	57117-44-9					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,7,8,9-HEXACHLORODIBENZOFURAN	72918-21-9					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
2,3,4,6,7,8-HEXACHLORODIBENZOFURAN	60851-34-5					4.0E-04	2/00	1.0E-07	10/00	3.8E+00	1.3E+04	4/99	1.3E+04	10/00	1
1,2,3,4,6,7,8-HEPTACHLORODIBENZOFURAN	67562-39-4					4.0E-03	2/00	1.0E-06	10/00	3.8E-01	1.3E+03	4/99	1.3E+03	10/00	1
1,2,3,4,7,8,9-HEPTACHLORODIBENZOFURAN	55673-89-7					4.0E-03	2/00	1.0E-06	10/00	3.8E-01	1.3E+03	4/99	1.3E+03	10/00	1
1,2,3,4,6,7,8,9-OCTACHLORODIBENZOFURAN	39001-02-0					4.0E-01	8/03	1.0E-04	8/03	3.8E-03	1.3E+01	8/03	1.3E+01	8/03	1
POLYCYCLIC AROMATIC HYDROCARBON (PAH) Φ [Treated as B(a)P for HRA]❖	1150 1151									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
BENZ(A)ANTHRACENE❖	56-55-3									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
BENZO(A)PYRENE❖	50-32-8									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
BENZO(B)FLUORANTHENE❖	205-99-2									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
BENZO(J)FLUORANTHENE❖	205-82-3									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
BENZO(K)FLUORANTHENE❖	207-08-9									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
CHRYSENE❖	218-01-9									1.1E-05	3.9E-02	4/99 [4/94]	1.2E-01	10/00 [4/94]	1
DIBENZ(A,H)ACRIDINE❖	226-36-8									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
DIBENZ(A,H)ANTHRACENE❖	53-70-3									1.2E-03	4.1E+00	4/99 [4/94]	4.1E+00	10/00 [4/94]	1
DIBENZ(A,J)ACRIDINE❖	224-42-0									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
DIBENZO(A,E)PYRENE❖	192-65-4									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
DIBENZO(A,H)PYRENE❖	189-64-0									1.1E-02	3.9E+01	4/99 [4/94]	1.2E+02	10/00 [4/94]	1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES❖

Substance	Chemical▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date◆ Value Reviewed [Added]	Inhalation* Unit Risk (µg/m^3)$^{-1}$	Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date◆ Value Reviewed [Added]	M♣ W A F
DIBENZO(A,I)PYRENE❖	189-55-9									1.1E-02	3.9E+01	4/99 [4/94]	1.2E+02	10/00 [4/94]	1
DIBENZO(A,L)PYRENE❖	191-30-0									1.1E-02	3.9E+01	4/99 [4/94]	1.2E+02	10/00 [4/94]	1
7H-DIBENZO(C,G)CARBAZOLE❖	194-59-2									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
7,12-DIMETHYLBENZ(A)ANTHRACENE❖	57-97-6									7.1E-02	2.5E+02	4/99 [4/94]	2.5E+02	10/00 [4/94]	1
1,6-DINITROPYRENE❖	42397-64-8									1.1E-02	3.9E+01	4/99 [4/94]	1.2E+02	10/00 [4/94]	1
1,8-DINITROPYRENE❖	42397-65-9									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
INDENO(1,2,3-C,D)PYRENE❖	193-39-5									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
3-METHYLCHOLANTHRENE❖	56-49-5									6.3E-03	2.2E+01	4/99 [4/94]	2.2E+01	10/00 [4/94]	1
5-METHYLCHRYSENE❖	3697-24-3									1.1E-03	3.9E+00	4/99 [4/94]	1.2E+01	10/00 [4/94]	1
NAPHTHALENE	91-20-3					9.0E+00	4/00			3.4E-05	1.2E-01	8/04			1
5-NITROACENAPHTHENE❖	602-87-9									3.7E-05	1.3E-01	4/99 [4/94]	1.3E-01	10/00 [4/94]	1
6-NITROCHRYSENE❖	7496-02-8									1.1E-02	3.9E+01	4/99 [4/94]	1.2E+02	10/00 [4/94]	1
2-NITROFLUORENE❖	607-57-8									1.1E-05	3.9E-02	4/99 [4/94]	1.2E-01	10/00 [4/94]	1
1-NITROPYRENE❖	5522-43-0									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
4-NITROPYRENE❖	57835-92-4									1.1E-04	3.9E-01	4/99 [4/94]	1.2E+00	10/00 [4/94]	1
POTASSIUM BROMATE.... ... (see Bromine & Compounds)															
1,3-PROPANE SULTONE	1120-71-4									6.9E-04	2.4E+00	4/99			1
PROPYLENE (PROPENE)	115-07-1					3.0E+03	4/00								1
PROPYLENE GLYCOL MONOMETHYL ETHER	107-98-2					7.0E+03	2/00								1
PROPYLENE OXIDE	75-56-9	3.1E+03	4/99			3.0E+01	2/00			3.7E-06	1.3E-02	4/99 [7/90]			1
SELENIUM AND COMPOUNDS	7782-49-2 [1170]					2.0E+01	12/01								1
HYDROGEN SELENIDE	7783-07-5	5.0E+00	4/99												1
Selenium sulfide	*7446-34-6*					*2.0E+01*	*12/01*								*1*

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

		Noncancer Effects								Cancer Risk					
Substance	**Chemical▼ Abstract Number**	**Acute Inhalation (µg/m^3)**	**Date◆ Value Reviewed [Added]**	**8-Hour Inhalation (µg/m^3)**	**Date◆ Value Reviewed [Added]**	**Chronic Inhalation (µg/m^3)**	**Date◆ Value Reviewed [Added]**	**Chronic Oral (mg/kg-d)**	**Date◆ Value Reviewed [Added]**	**Inhalation* Unit Risk (µg/m^3)$^{-1}$**	**Inhalation* Cancer Potency Factor (mg/kg-d)$^{-1}$**	**Date◆ Value Reviewed [Added]**	**Oral Slope Factor (mg/kg-d)$^{-1}$**	**Date◆ Value Reviewed [Added]**	**M♣ W A F**
SILICA [CRYSTALLINE, RESPIRABLE]	1175					3.0E+00	2/05								1
SODIUM HYDROXIDE	1310-73-2	8.0E+00	4/99												1
STYRENE	100-42-5	2.1E+04	4/99			9.0E+02	4/00								1
SULFATES	9960	1.2E+02	4/99												1
SULFUR DIOXIDE	7446-09-5	6.6E+02	4/99[1/92]												1
SULFURIC ACID AND OLEUM	9961	1.2E+02	4/99			*1.0E+00*	*12/01*								1
SULFURIC ACID	*7664-93-9*	*1.2E+02*	*4/99*			1.0E+00	12/01								*1*
SULFUR TRIOXIDE	*7446-71-9*	*1.2E+02*	*4/99*			*1.0E+00*	*12/01*								*1*
OLEUM	*8014-95-7*	*1.2E+02*	*4/99*			*1.0E+00*	*12/01*								*1*
1,1,2,2-TETRACHLOROETHANE	79-34-5									5.8E-05	2.0E-01	4/99			1
TETRACHLOROPHENOLS ... (see Chlorophenols)															
2,4,5-TRICHLOROPHENOL ... (see Chlorophenols)															
2,4,6-TRICHLOROPHENOL ... (see Chlorophenols)															
THIOACETAMIDE	62-55-5									1.7E-03	6.1E+00	4/99			1
TOLUENE	108-88-3	3.7E+04	4/99			3.0E+02	4/00								1
Toluene diisocyantates	*26471-62-5*					*7.0E-02*	*1/01*			*1.1E-05*	*3.9E-02*	*4/99*			*1*
TOLUENE-2,4-DIISOCYANATE	584-84-9					7.0E-02	1/01			1.1E-05	3.9E-02	4/99			1
TOLUENE-2,6-DIISOCYANATE	91-08-7					7.0E-02	1/01			1.1E-05	3.9E-02	4/99			1
1,1,2-TRICHLOROETHANE (Vinyl trichloride)	79-00-5									1.6E-05	5.7E-02	4/99			1
TRICHLOROETHYLENE^{TAC}	79-01-6					6.0E+02	4/00			2.0E-06 TAC	7.0E-03	10/90			1
TRIETHYLAMINE	121-44-8	2.8E+03	4/99			2.0E+02	9/02								1
URETHANE (Ethyl carbamate)	51-79-6									2.9E-04	1.0E+00	4/99 [7/90]			1
Vanadium Compounds	*N/A*														*1*
Vanadium (fume or dust)	*7440-62-2*	*3.0E+01*	*4/99*												*1*
VANADIUM PENTOXIDE	1314-62-1	3.0E+01	4/99												1
VINYL ACETATE	108-05-4					2.0E+02	12/01								1
VINYL CHLORIDE^{TAC} (Chloroethylene)	75-01-4	1.8E+05	4/99							7.8E-05 TAC	2.7E-01	12/90			1
VINYLIDENE CHLORIDE (1,1-Dichloroethylene)	75-35-4					7.0E+01	1/01								1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

Substance	Chemical ▼ Abstract Number	Noncancer Effects								Cancer Risk					
		Acute Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	8-Hour Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	Chronic Inhalation (µg/m^3)	Date ◆ Value Reviewed [Added]	Chronic Oral (mg/kg-d)	Date ◆ Value Reviewed [Added]	Inhalation * Unit Risk (µg/m^3)$^{-1}$	Inhalation * Cancer Potency Factor (mg/kg-d)$^{-1}$	Date ◆ Value Reviewed [Added]	Oral Slope Factor (mg/kg-d)$^{-1}$	Date ◆ Value Reviewed [Added]	M ♣ W A F
XYLENES (mixed isomers)	1330-20-7	2.2E+04	4/99			7.0E+02	4/00								1
m-XYLENE	108-38-3	2.2E+04	4/99			7.0E+02	4/00								1
o-XYLENE	95-47-6	2.2E+04	4/99			7.0E+02	4/00								1
p-XYLENE	106-42-3	2.2E+04	4/99			7.0E+02	4/00								1

Table 1
CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES☼

Purpose: The purpose of this reference table is to provide a quick list of all health values that have been approved by the Office of Environmental Health Hazard Assessment (OEHHA) and the Air Resources Board (ARB) for use in facility health risk assessments conducted for the AB 2588 Air Toxics Hot Spots Program. The OEHHA has developed and adopted new risk assessment guidelines that update and replace the California Air Pollution Control Officers Association's (CAPCOA) *Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines, October 1993*. The OEHHA has adopted four technical support documents for these guidelines, which can be found on their website (http://www.oehha.ca.gov/air/hot_spots/index.html). This table lists the OEHHA adopted inhalation and oral cancer slope factors, noncancer acute Reference Exposure Levels (RELs), and inhalation and oral noncancer chronic RELs. OEHHA is still in the process of adopting new health values. Therefore, new health values will periodically be added to, or deleted from, this table. Users of this table are advised to monitor the OEHHA website (*www.oehha.ca.gov*) for any updates to the health values.

May 2008 update: The Air Resources Board adopted amendments to the AB 2588 Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines Regulation (Title 17, California Code of Regulations, Section 93300.5) on November 16, 2006. The amendments became effective on September 26, 2007, after approval from the Office of Administrative Law. Under the new amendments, the substances previously listed in Appendix A-I *(Substances For Which Emissions Must Be Quantified*) and Appendix F (*Criteria For Inputs For Risk Assessment Using Screening Air Dispersion Modeling*) of the ARB's *Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines (EICG) (July 1997)* have been removed from this table.

☼ Substances written in *italics* do not have explicit OEHHA approved health values, but are included in this table to clarify applicability of OEHHA adopted heath effects values to individual or grouped substances listed in the *Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines*, Appendix A-I list of *"Substances For Which Emissions Must Be Quantified"*.

▼ Chemical Abstract Service Number (CAS): For chemical groupings and mixtures where a CAS number is not applicable, the 4-digit code used in the *Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines (EICG) Report* is listed. The 4-digit codes enclosed in brackets [ ] are codes that have been phased out, but may still appear on previously reported Hot Spots emissions. For information on the origin and use of the 4-digit code, see the EICG report.

◆ Date Value Reviewed [Added]: These columns list the date that the health value was last reviewed by OEHHA and the Scientific Review Panel, and/or approved for use in the AB 2588 Air Toxics Hot Spots Program. If the health value is unchanged since it was first approved for use in the Hot Spots Program, then the date that the value was first approved for use by CAPCOA is listed within the brackets [ ].

- April 1999 is listed for the cancer potency values and noncancer acute RELs, which have been adopted by the OEHHA as part of the AB 2588 Hot Spot Risk Assessment Guidelines.
- February 2000, April 2000, January 2001, and December 2001 are listed for the first set of 22, the second set of 16, the third set of 22, and the fourth set of 12 noncancer chronic RELs, respectively. The chronic REL for carbon disulfide was adopted in May 2002. Chronic RELs for phosphine and triethylamine were adopted in September 2002. Chronic RELs for fluorides including hydrogen fluoride were adopted August 2003. Chronic REL for silica [crystalline respirable] was adopted February 2005.
- October 2000 is listed for the oral chronic RELs and oral cancer slope factors.
- Cancer potency value adopted for naphthalene in August 2004. The inhalation and oral cancer potency values for ethyl benzene were adopted in November 2007.
- For the substances identified as Toxic Air Contaminants, the Air Resources Board hearing date is listed. The dates for acetaldehyde, benzo[a]pyrene, and methyl tertiary-butyl ether represent the dates the values were approved by the Scientific Review Panel.
- On December 19, 2008, OEHHA adopted new acute, 8-hour, and chronic RELs for acetaldehyde, acrolein, arsenic, formaldehyde, manganese, and mercury. The most current health values can be found at: http://www.oehha.ca.gov/air/allrels.html. Note that the 8-hour RELs are not included in the HARP program. These health factors will be added after OEHHA approves the Guidelines Manual (Part V).

Note: 1. OEHHA presents the new oral RELs in micrograms (µg/kg-d) and we converted them to milligrams (mg/kg-d) for consistency.

2. Acute RELs with longer averaging periods (i.e., 4-hour, 6-hour, and 7-hour) will now use the 1-hour averaging period. The affected chemicals are: arsenic & inorganic arsenic compounds, benzene, carbon disulfide, carbon tetrachloride, chloroform, ethylene glycol monoethyl ether, ethylene glycol monoethyl ether acetate, and ethylene glycol monomethyl ether.

3. At OEHHA's direction, the chronic oral REL for arsenic does not apply to arsine because arsine is a gas and not particle associated.

* Inhalation cancer potency factor: The "unit risk factor" has been replaced in the new risk assessment algorithms by a factor called the "inhalation cancer potency factor". Inhalation cancer potency factors are expressed as units of inverse dose [i.e., $(mg/kg\text{-}day)^{-1}$]. They were derived from unit risk factors [units = $(ug/m^3)^{-1}$] by assuming that a receptor weighs 70 kilograms and breathes 20 cubic meters of air per day. The inhalation potency factor is used to calculate a potential inhalation cancer risk using the new risk assessment algorithms defined in the OEHHA, *Air Toxics Hot Spots Program; Part IV; Technical Support Document for Exposure Assessment and Stochastic Analysis (September 2000)*.

♣ Molecular Weight Adjustment Factor: Molecular weight adjustment factors (MWAF) are only to be used when a toxic metal has a cancer potency factor. For most of the Hot Spots toxic metals, the OEHHA cancer potency factor applies to the weight of the toxic metal atom contained in the overall compound. Some of the Hot Spots compounds contain various elements along with the toxic metal atom (e.g., "Nickel hydroxide", CAS number 12054-48-7, has a formula of H_2NiO_2). Therefore, an adjustment to the reported pounds of the overall compound is needed before applying the OEHHA cancer potency factor for "Nickel and compounds" to such a compound. This ensures that the cancer potency factor is applied only to the fraction of the overall weight of the emissions that are associated with health effects of the metal. In other cases, the Hot Spots metals are already reported as the metal atom equivalent (e.g., CAS 7440-02-0, "Nickel"), and these cases do not use any further molecular weight adjustment. (Refer to Note [7] in Appendix A, List of Substances in the EICG Report for further information on how the emissions of various Hot Spots metal compounds are reported.) The appropriate molecular weight adjustment factors (MWAF) to be used along with the OEHHA cancer potency factors for Hot Spots metals can be found in the MWAF column of this table.

So, for example, assume 100 pounds of "Nickel hydroxide" emissions are reported under CAS number 12054-48-7. To get the Nickel atom equivalent of these emissions, multiply by the listed MWAF (0.6332) for Nickel hydroxide:

- 100 pounds x 0.6332 = 63.32 pounds of Nickel atom equivalent

This step should be completed prior to applying the OEHHA cancer potency factor for "Nickel and compounds" in a calculation for a prioritization score or risk assessment calculation. (For more information see Chapter 8 of OEHHA's document, *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments*.)

Note: The value listed in the MWAF column for Asbestos is not a molecular weight adjustment. This is a conversion factor for adjusting mass to fibers or structures. See Appendix C of OEHHA's document *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for more information on Asbestos, or see the EICG report for reporting guidance. Also see the Asbestos footnote (designated by the symbol ¤)

Table 1

CONSOLIDATED TABLE OF OEHHA/ARB APPROVED RISK ASSESSMENT HEALTH VALUES*

N/A	Not Applicable
TAC	Toxic Air Contaminant: The Air Resources Board has identified this substance as a Toxic Air Contaminant.
⌑	Asbestos: The units for the Inhalation Cancer Potency factor for asbestos are (100 PCM fibers/m^3)$^{-1}$. A conversion factor of 100 fibers/0.003 µg can be multiplied by a receptor concentration of asbestos expressed in µg/m^3. Unless other information necessary to estimate the concentration (fibers/m^3) of asbestos at receptors of interest is available. A unit risk factor of 1.9 E 10^{-4} (µg/m^3)$^{-1}$ and an inhalation cancer potency factor of 2.2 E 10^{+2} (mg/kg BW * day)$^{-1}$ are available. For more information on asbestos quantity conversion factors, see Appendix C of OEHHA's *The Air Toxics Hot Spots Program Risk Assessment Guidelines; Part II; Technical Support Document for Describing Available Cancer Potency Factors*, and Appendix C of OEHHA's document *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments*.
∅	Hexavalent Chromium: The oral cancer slope factor for chromium 6+ and compounds has been withdrawn by the Office of Environmental Health Hazard Assessment.
♫	Inorganic Lead: Inorganic Lead was identified by the Air Resources Board as a Toxic Air Contaminant in April 1997. Since information on noncancer health effects show no identified threshold, no Reference Exposure Level has been developed. The document, *Risk Management Guidelines for New, Modified, and Existing Sources of Lead, March 2001*, has been developed by ARB and OEHHA staff for assessing noncancer health impacts from sources of lead. See Appendix F of OEHHA's document *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for an overview of how to evaluate noncancer impacts from exposure to lead using these risk management guidelines.
Φ	Polycyclic Aromatic Hydrocarbons (PAHs): These substances are PAH or PAH-derivatives that have OEHHA-developed Potency Equivalency Factors (PEFs) which were approved by the Scientific Review Panel in April 1994 (see ARB document entitled *Benzo[a]pyrene as a Toxic Air Contaminant*). PAH inhalation slope factors listed here have been adjusted by the PEFs. See Appendix G of OEHHA's document *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for more information. See section 8.2.3 of OEHHA's *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for conducting health risks when total (unspeciated) PAHs are reported.
☼	Polychlorinated Biphenyls: (unspeciated mixtures) Lowest Risk: For use in cases where congeners with more than four chlorines comprise less than one-half percent of total polychlorinated biphenyls. High Risk: For use in cases where congeners with more than four chlorines do not comprise less than one-half percent of total polychlorinated biphenyls. Low Risk: This number would not ordinarily be used in the Hot Spots program. Chronic Oral: The chronic oral value is U.S. EPA's 1996 oral Reference Dose for Aroclor-1254.
ϖ	Polychlorinated Biphenyls (speciated): Values calculated using WHO_{97} TEF procedure. See OEHHA memo dated August 29, 2003.
●	Polychlorinated Dibenzo-*p*-dioxins and Polychlorinated Dibenzofurans (also referred to as chlorinated dioxins and dibenzofurans): The OEHHA has adopted the World Health Organization 1997 (WHO-$_{97}$) Toxicity Equivalency Factor scheme for evaluating the cancer risk due to exposure to samples containing mixtures of polychlorinated dibenzo-*p*-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF) and determining cancer risks for a number of specific PCB congeners. See Appendix A of OEHHA's *Technical Support Document For Describing Available Cancer Potency Factors* for more information about the scheme. See Appendix E of OEHHA's *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for the methodology for calculating 2,3,7,8-equivalents for PCDD, PCDFs and a number of specific PCB congeners. See section 8.2.3 of OEHHA's *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for conducting health risks when total (unspeciated) chlorinated dioxins and furans are reported.
ς	Particulate Emissions from Diesel-Fueled Engines: The inhalation cancer potency factor and chronic REL were derived from whole diesel exhaust and should be used only for impacts from the inhalation pathway. The inhalation impacts from speciated emissions from diesel-fueled engines are already accounted for in the inhalation cancer potency factor and REL. However, at the discretion of the risk assessor, speciated emissions from diesel-fueled engines may be used to estimate acute noncancer health impacts or the contribution to cancer risk or chronic noncancer health impacts for the non-inhalation exposure pathway. See Appendix D of OEHHA's document *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* for more information.

Figure 5.1D-1 Sensitive Receptor Map

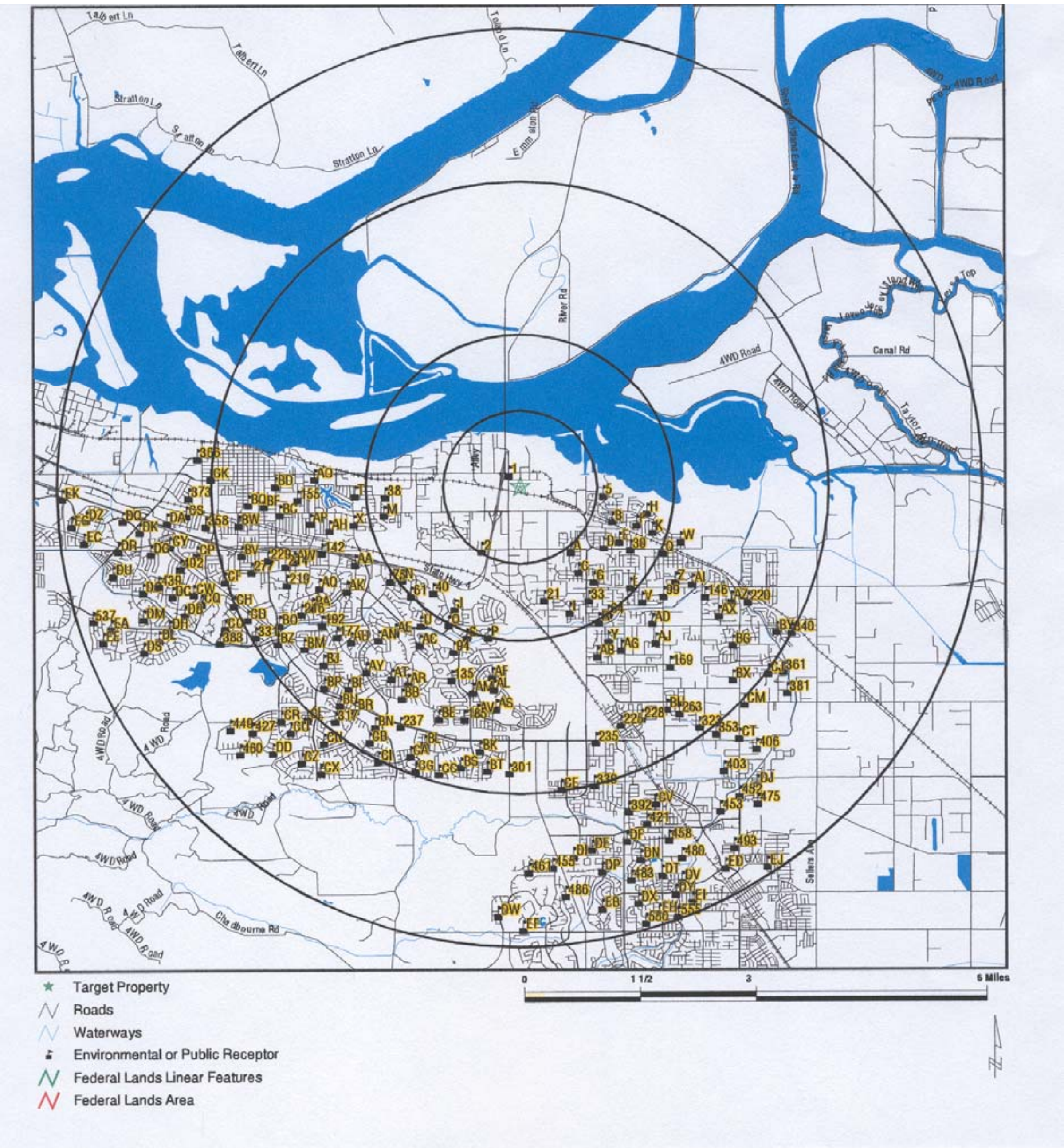


Figure 5.1D-2 Census Tracts in the Immediate Impact Area

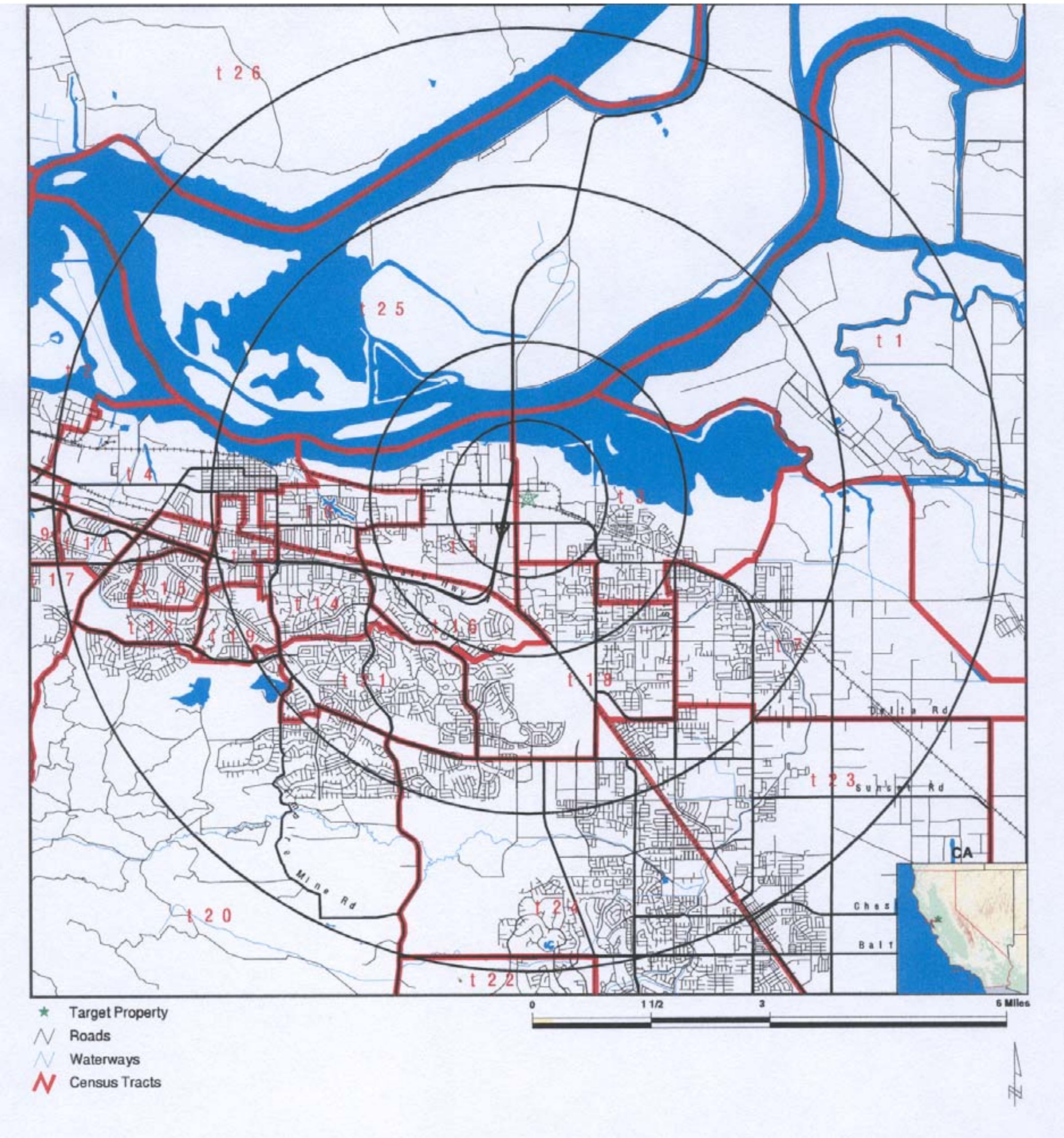
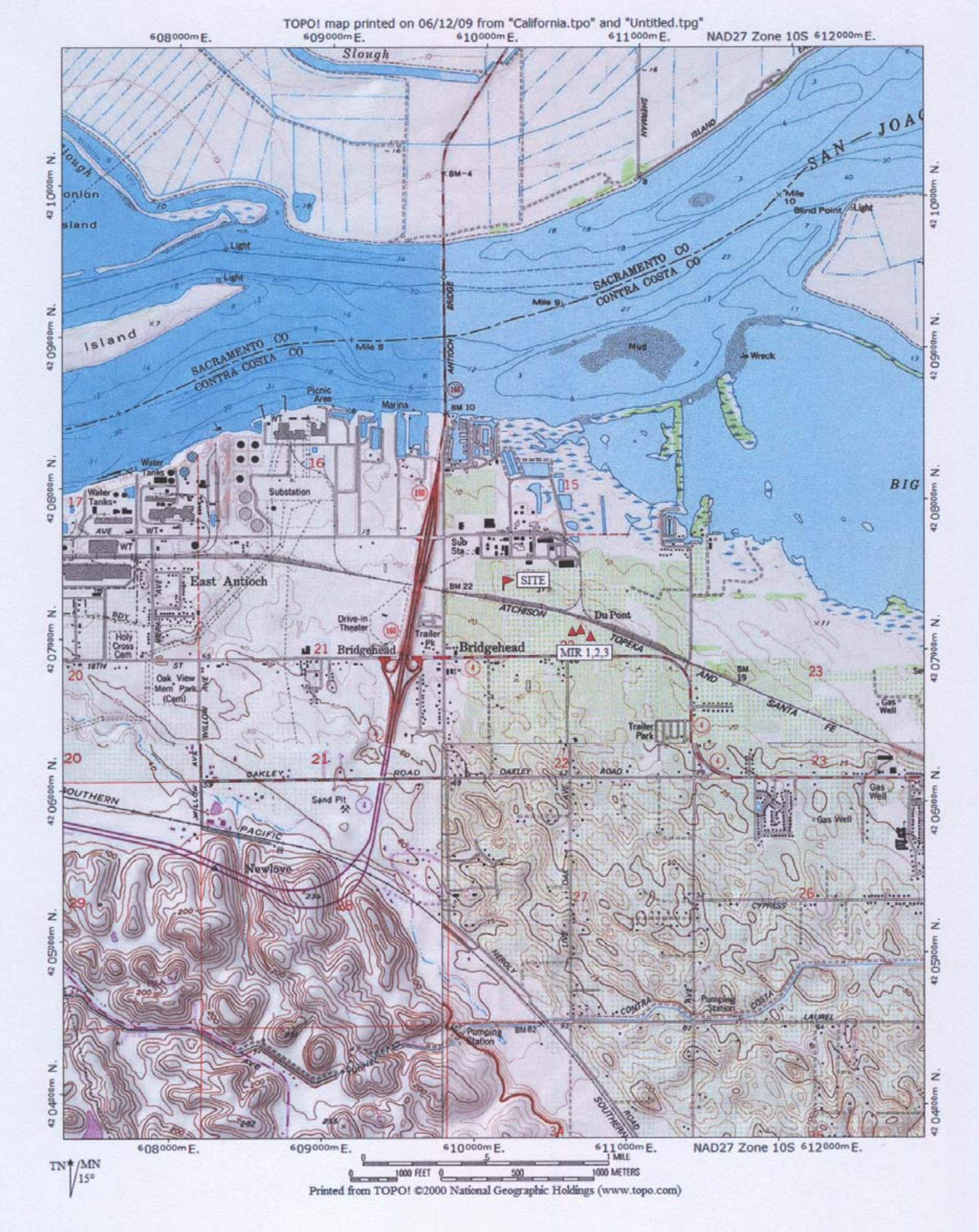


Figure 5.1D-3 MIR 1, 2, and 3 Location Map



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APPENDIX 5.1E

Construction Data

APPENDIX 5.1E

Construction Emissions and Impact Analysis

Construction Phases

Construction of OGS is expected to last approximately 33 months. The construction will occur in the following four main phases:

- Site preparation;
- Foundation work;
- Construction/installation of major structures; and,
- Installation of major equipment.

The main site is approximately 20 acres in size and is essentially flat. A laydown yard sized at 20 acres lies immediately adjacent to the main site. The total acreage for purposes of calculating on-site emissions will be approximately 20 acres. Offsite linear acreage will be approximately 5.27 acres. The site is currently part of the existing DuPont facility (see Project Description section). As such, the site will require only minimum grading and leveling prior to construction of the power block and cooling tower cell additions. Site preparation includes finish grading, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence.

Fugitive dust emissions from the construction of OGS will result from:

- Dust entrained during site preparation and finish grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

Combustion emissions during construction will result from:

- Exhaust from the Diesel construction equipment used for site preparation, grading, excavation, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from Diesel-powered welding machines, electric generators, air compressors, and water pumps;
- Exhaust from pickup trucks and Diesel trucks used to transport workers and materials around the construction site;
- Exhaust from Diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site; and,

- Exhaust from automobiles used by workers to commute to the construction site.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Worst-case daily dust emissions are expected to occur during the first 2-6 months of construction when site preparation occurs. The worst-case daily exhaust emissions are expected to occur during the middle of the construction schedule during the installation of the major mechanical equipment. Annual emissions are based on the average equipment mix during the 20 month construction period.

Available Mitigation Measures

The following mitigation measures are proposed to control fugitive dust and exhaust emissions from the Diesel heavy equipment used during construction of OGS:

- The applicant will have an on-site construction mitigation manager who will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the proposed construction mitigations will be provided on a periodic basis.
- All unpaved roads and disturbed areas in the project and laydown construction sites will be watered as frequently as necessary to control fugitive dust. The frequency of watering will be on a minimum schedule of four (4) times during the daily construction activity period. Watering may be reduced or eliminated during periods of precipitation.
- Onsite vehicle speeds will be limited to 5 miles per hour on unpaved areas within the project construction site.
- The construction site entrance(s) will be posted with visible speed limit signs.
- All construction equipment vehicle tires will be inspected and cleaned as necessary to be free of dirt prior to leaving the construction site via paved roadways.
- Gravel ramps will be provided at the tire cleaning area.
- All unpaved exits from the construction site will be graveled or treated to reduce track-out to public roadways.
- All construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been provided.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other similar measures as specified in the construction Storm Water Pollution Prevention Plan (SWPPP) to prevent runoff to roadways.
- All paved roads within the construction site will be cleaned on a periodic basis (or less during periods of precipitation), to prevent the accumulation of dirt and debris.

- The first 300 feet of any public roadway exiting the construction site will be cleaned on a periodic basis (or less during periods of precipitation), using wet sweepers or air filtered dry vacuum sweepers, when construction activity occurs or on any day when dirt or runoff from the construction site is visible on the public roadways.

- Any soil storage piles and/or disturbed areas that remain inactive for longer than 10 days will be covered, or shall be treated with appropriate dust suppressant compounds.

- All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions will be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to minimize fugitive dust emissions. A minimum freeboard height of two (2) feet will be required on all bulk materials transport.

- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition will remain in place until the soil is stabilized or permanently covered with vegetation.

- Disturbed areas will be re-vegetated as soon as practical.

To mitigate exhaust emissions from construction equipment, the applicant is proposing the following:

- The applicant will work with the construction contractor to utilize to the extent feasible, EPA-ARB Tier 2/Tier 3 engine compliant equipment for equipment over 100 horsepower.

- Insure periodic maintenance and inspections per the manufacturers specifications.

- Reduce idling time through equipment and construction scheduling.

- Use California low sulfur diesel fuels (<=15 ppmw S).

Estimation of Emissions with Mitigation Measures

Tables 5.1E-1 through 5.1E-3 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures. Detailed emission calculations are included in Table 5.1E-5, including estimates of PM2.5 and CO2e.

Table 5.2E-1 Average Daily Onsite Emissions During Construction, pounds per day

	NO_x	CO	VOC	SO_x	$PM_{10}/PM_{2.5}$
Construction Fugitive Dust	0	0	0	0	12.7/2.7
Equipment and Vehicle Exhaust	106.3	54.1	16	0.1	6.1/6.1
Total =	**106.3**	**54.1**	**16.0**	**0.1**	**18.8/8.8**

Table 5.2E-2 Average Annual Onsite Emissions During Construction, tons per year

	NO_x	CO	VOC	SO_x	$PM_{10}/PM_{2.5}$
Construction Fugitive Dust	0	0	0	0	0.50/0.10
Equipment and Vehicle Exhaust	14.0	7.1	2.1	0.004	0.81/0.80
Total =	**14.0**	**7.1**	**2.1**	**0.004**	**1.31/0.90**

Table 5.2E-3 Annual Onsite Emissions During Construction, tons per construction period (33 months)

	NO_x	CO	VOC	SO_x	$PM_{10}/PM_{2.5}$
Construction Fugitive Dust	0	0	0	0	1.1/0.2
Equipment and Vehicle Exhaust	38.6	19.6	5.8	0.01	2.23/2.21
Total =	**38.6**	**19.6**	**5.8**	**0.01**	**3.3/2.41**

Analysis of Ambient Impacts from Facility Construction

Ambient air quality impacts from emissions during the construction of OGS were estimated using an air quality dispersion modeling analysis. The modeling analysis considers the construction site location, the surrounding topography, and the sources of emissions during construction, including vehicle and equipment exhaust emissions and fugitive dust.

Existing Ambient Levels

As with the modeling analysis of project operating impacts (Section 5.1), monitoring stations delineated in Section 5.1 were used to establish the ambient background levels for the construction impact modeling analysis. Table 5.1-17 showed the maximum concentrations of NO_x, SO_2, CO, $PM_{2.5}$, and PM_{10} recorded for 2006 through 2008 at those monitoring stations.

Dispersion Model

As in the analysis of project operating impacts, the USEPA-approved model AERMOD (version09292) was used to estimate ambient impacts from construction activities. A detailed discussion of the AERMOD dispersion model and the associated processing programs AERSURFACE, AERMET, and AERMAP is included in Section 5.1.5. As with the operational impact analysis, the PG&E meteorological data collected at the Contra Costa Power Plant (CCP, approximately 1.5 km northwest of the project site) and provided by BAAQMD, reprocessed for the surface characteristics of the proposed project site, were used in the construction impact analysis.

The emission sources for the construction site were grouped into two categories: exhaust emissions and dust emissions. Combustion equipment exhaust emissions were modeled as twenty-nine (29) 3.048 meter high point sources (exhaust parameters of 750 Kelvins, 64.681 m/s exit velocity, and 0.1524 meter stack diameter) placed at regular 50-meter intervals around the construction area. Construction fugitive dust emissions were modeled as an area source covering the construction area with an effective plume height of 0.5 meters. Combustion and fugitive emissions were assumed to occur for 10 hours/day (8 AM to 6 PM) consistent with the expected period of onsite construction activities generating both exhaust emissions and fugitive dust. The construction impacts modeling analysis used the same receptor locations and meteorological data as used for the project operating impact analysis. A detailed discussion of the receptor locations and meteorological data is included in Section 5.1.5. For the construction impacts modeling involving area sources, the FASTALL keyword was used to minimize execution times.

To determine the construction impacts on short-term ambient standards (24 hours and less), the average daily onsite construction emission levels shown in Table 5.1E-1 were used. For pollutants with annual average ambient standards, the annual onsite emission levels as shown in Table 5.1E-2 were used.

Modeling Results

Based on the emission rates of NO_x, SO_2, CO, $PM_{2.5}$, and PM_{10}, the modeling options, receptor grids, and meteorological data, AERMOD calculates short-term and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NO_x, SO_2, CO, $PM_{2.5}$, and PM_{10} spread over the estimated daily hours of operation. The annual impacts are based on the annual emission rates of these pollutants.

Like the operational impact analyses, 1-hour NO_2 impacts were calculated separately using the Ozone Limiting Method (OLM keyword) with concurrent Pittsburg ozone data and all facility NO_X emissions included in one OLM source group. The maximum modeled 1-hour

NO_2 impact with OLM was added to the worst-case 1-hour NO_2 background value (from 2006-08) for comparison to the 1-hour NO_2 CAAQS of 339 µg/m^3. In order to demonstrate compliance with the 1-hour NO_2 NAAQS of 188 µg/m^3 based on the 5-year average of the 8th highest daily 1-hour maximum (i.e., for all five years of the meteorological data modeled), a post-processing FORTRAN program was required, which also included the concurrent 1-hour Pittsburg NO_2 background concentration in the calculations. A more detailed discussion of the NO_2 processing is contained in Section 5.1.5. The annual average concentrations of NO_2 were computed following the revised USEPA guidance for computing these concentrations (August 9, 1995 Federal Register, 60 FR 40465). The annual average was calculated using the ambient ratio method (ARM) with the national default value of 0.75 for the annual average NO_2/NO_x ratio.

The modeling analysis results are shown in Table 5.1E-4. Also included in the table are the maximum background levels that have occurred in the last three years and the resulting total ambient impacts. As shown in Table 5.1E-4, modeled construction impacts for all pollutants are expected to be below the most stringent state and Federal standards. However, the state annual NO_2 standard, the state 24-hour and annual PM_{10} standards, and the state and Federal $PM_{2.5}$ standards are exceeded by maximum background concentrations even in the absence of the modeled impacts due to construction emissions for OGS.

TABLE 5.1E-4 MODELED MAXIMUM CONSTRUCTION IMPACTS

Pollutant	Averaging Time	Maximum Construction Impacts (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	State Standards (µg/m^3)	Federal Standards (µg/m^3)
NO_2[a]	1-hour	89.9	98.1	188.0	339	-
	98th %	22.1	72.0	94.1	–	188
	Annual	4.0	20.8	24.8	57	100
SO_2	1-hour	0.10	122.2	122.3	655	-
	3-hour	0.08	65.0	65.08	-	1300
	24-hour	0.02	23.4	23.42	105	365
	Annual	0.001	7.8	7.8	-	80
CO	1-hour	47.7	3771	3819	23,000	40,000
	8-hour	17.7	2171	2189	10,000	10,000
PM_{10}	24-hour	96.42.31	82	178.4	50	150
	Annual[b]		24	26.3	20	-
$PM_{2.5}$	24-hour	20.6	35	55.6	-	35
	Annual	0.60	9	9.6	12	15.0

Notes:

[a] OLM applied for 1-hour averages using AERMOD OLM keyword and Pittsburg ozone data. Five-year average concentrations of the 98th percentile daily maximum concentrations evaluated by a post-processor after including concurrent background Pittsburg NO_2 data.
ARM applied for annual average, using national default 0.75 ratio.

[b] Annual Arithmetic Mean.

For maximum modeled ambient concentrations due to construction emissions only, standards are only exceeded for the state 24-hour PM_{10} standard. All other maximum modeled construction impacts are less than the applicable state or Federal standards. Total concentrations (maximum modeled impacts plus maximum background concentrations) only exceed standards for those pollutants and averaging times where background concentrations are close to or already exceed the standards (i.e., the 24-hour and annual PM_{10} standards and 24-hour Federal $PM_{2.5}$ standard). Maximum total concentrations (modeled+background) for all other pollutants and averaging times are less than the applicable standards – i.e., the state and Federal NO_2 standards, the state and Federal SO_2 standards, the state and Federal CO standards, and the annual $PM_{2.5}$ standards. Modeled OGS construction particulate impacts are not unusual in comparison to the modeling results for most construction projects; construction sites that use good dust suppression techniques and low-emitting vehicles typically would not be expected to cause exceedances of air quality particulate standards. The input and output modeling files are being provided electronically to the appropriate agencies.

Attachment - Detailed Emission Calculations

Table 5.1E-5	Construction Emissions Calculations
Table 5.1E-6	EMFAC Burden Output for SFAB – 2011
Table 5.1E-7	EMFAC Composites for Emissions Calculations

Table 5.1E-5 **Construction Emission Totals**

	lbs/day						tons per const period						tons per year					
Construction Activity	**NOx**	**CO**	**VOC**	**SOx**	**PM10**	**PM2.5**	**NOx**	**CO**	**VOC**	**SOx**	**PM10**	**PM2.5**	**NOx**	**CO**	**VOC**	**SOx**	**PM10**	**PM2.5**
Main Site																		
Construction Equipment-Exhaust	106.3	54.1	16.0	0.1	6.14	6.10	38.6	19.6	5.80	0.01	2.23	2.21	14.04	7.13	2.11	0.00	0.81	0.80
Construction Site-Fugitive Dust	0.000	0.000	0.000	0.000	15.60	3.30	0.000	0.000	0.000	0.000	1.10	0.20	0.00	0.00	0.00	0.00	0.40	0.07
Construction Dust-Other	0.000	0.000	0.000	0.000	0.90	0.19	0.000	0.000	0.000	0.000	0.27	0.06	0.00	0.00	0.00	0.00	0.10	0.02
Site Delivery-Vehicle Exhaust	7.52	2.10	0.43	0.011	0.29	0.28	2.73	0.76	0.15	0.004	0.100	0.100	0.99	0.28	0.05	0.00	0.04	0.04
Site Support-Vehicle Exhaust	1.200	11.600	1.200	0.002	0.110	0.110	0.440	4.200	0.430	0.001	0.040	0.040	0.16	1.53	0.16	0.00	0.01	0.01
Worker Travel-Vehicle Exhaust	2.45	26.2	2.76	0.003	0.24	0.24	0.90	9.50	1.00	0.001	0.090	0.088	0.33	3.45	0.36	0.00	0.03	0.03
Track Out-Fugitive Dust	0.000	0.000	0.000	0.000	0.94	0.160	0.000	0.000	0.000	0.000	0.28	0.05	0.00	0.00	0.00	0.00	0.10	0.02
Unpaved Roads-Fugitive Dust	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.00	0.00	0.00	0.00	0.00
Paved Roads-Fugitive Dust	0.000	0.000	0.000	0.000	0.460	0.050	0.000	0.000	0.000	0.000	0.140	0.010	0.00	0.00	0.00	0.00	0.05	0.00
Offsite Linear Emissions are included in the above sector calculations, i.e., acreages, equipment types and use rates, schedules, etc.																		
TOTALS	**117.5**	**94.0**	**20.4**	**0.1**	**24.7**	**10.4**	**42.7**	**34.1**	**7.38**	**0.02**	**4.25**	**2.76**	**15.5**	**12.4**	**2.68**	**0.01**	**1.55**	**1.00**
Onsite Emissions for Modeling	*106.3*	*54.1*	*16.0*	*0.1*	*18.84*	*8.80*	*38.6*	*19.6*	*5.8*	*0.0*	*3.60*	*2.47*	*14.0*	*7.1*	*2.1*	*0.0*	*1.31*	*0.90*

Total Const Months:	33
Total Const Years:	2.75

CONSTRUCTION EQUIPMENT EXHAUST EMISSIONS

Project: CCGS

Assumptions:

1. The average diesel engine employed in construction equipment use consumes fuel at a rate of: 0.06 gal/hp-hr

Ref: EPA, NR-009b Publication, November 2002.
Ref: Sacramento County APCD Const. Program Data, V. 6.0.3, 3/2007.
Ref: EPA, NR-009c Publication, EPA 420-P-04-009, April 2004.
Ref: Niland Energy Project, IID, AFC Vol 2, App A.
Ref: South Coast AQMD PR XXI, Draft Staff Report, 3-15-95, and SCAQMD CEQA Manual, 11/03.

The above noted references present fuel consumption values which range from 0.050 to 0.064 gal/hp-hr for diesel engines used in construction related equipment. The value of 0.060 gal/hp-hr was chosen as a reasonable upper mid-range value for construction emissions calculations.

2. Construction equipment exhaust emissions will be calculated on an annual basis using the site specific equipment list, HP ratings, hours of use, days of use, etc. Annual emissions will be apportioned to daily values based on the estimated construction period time on site.

3. The equipment list derived from the South Coast AQMD (12/2006) will be used to establish the various equipment categories. Data produced by the Sacramento APCD was used to establish the average HP ratings for each equipment category. HP rating data was supplemented by data from SCAQMD CEQA Handbook (Table A9-8-C) if not available from Sacramento APCD.

4. Construction Schedule:	10	hrs/day	Construction Totals:	220	hrs/month
	5	days/week		7260	hrs/const period
	22	days/month		726	days/const period
	33	months			

5. Anticipated Construction Start Year: Late 2010 or early 2011

Equipment Category	Avg HP	# of Units Used for Project	Avg Use Rate Hrs/day	# of Days On Site (each)	Total Hrs/Day	Total Hp-Hrs per Day	Total Hrs per Const Period	Total Hp-Hrs per Const Period
Bore/Drill Rigs/Pile Drivers	217.7	2	10	30	20	4354	600	130620
Cement Mixers	11	1	10	10	10	110	100	1100
Industrial/Concrete Saws	83.7	1	10	10	10	837	100	8370
Cranes	190.4	4	10	500	40	7616	20000	3808000
Crawler Tractors/Dozers	143.4	2	10	60	20	2868	1200	172080
Crushing/Processing Eq.	154.3	0	0	0	0	0	0	0
Dump and Tender Trucks	223	5	10	180	50	11150	9000	2007000
Excavators	180	6	10	170	60	10800	10200	1836000
Forklifts/Aerial Lifts/Booms	83	5	10	400	50	4150	20000	1660000
Generators/Compressors	37	10	10	250	100	3700	25000	925000
Graders	174	2	10	120	20	3480	2400	417600
Off Highway Tractors	255.1	0	0	0	0	0	0	0
Off Highway Trucks	417.2	0	0	0	0	0	0	0
Other Const. Eq.-Diesel	240.3	0	0	0	0	0	0	0
Pavers	131.5	1	10	10	10	1315	100	13150
Paving Eq./Surfacing Eq.	110.9	0	0	0	0	0	0	0
Plate Compactors	8	4	10	450	40	320	18000	144000
Rollers/Compactors	113.9	2	10	100	20	2278	2000	227800
Rough Terrain Forklifts	94.2	0	0	0	0	0	0	0
Rubber Tired Dozers	352.5	0	0	0	0	0	0	0
Rubber Tired Loaders	165.3	0	0	0	0	0	0	0
Scrapers	313.2	4	10	60	40	12528	2400	751680
Signal Boards/Light Sets	118.8	5	10	180	50	5940	9000	1069200
Skid Steer Loaders	62	2	10	450	20	1240	9000	558000
Tractors/Loaders/Backhoes	79.5	0	0	0	0	0	0	0
Trenchers	28	0	0	0	0	0	0	0
Welders	35	10	10	250	100	3500	25000	875000
Other Const. Eq.-Gasoline	0	0	0	0	0	0	0	0

*includes equipment and use rates for proposed offsite linears.

Estimated Const Period Hp-Hrs = 14604600

Estimated Const Period Fuel Use = 876276 gals

		2010 Equipment Emissions Factors				
Equip.		**lbs/hp-hr**	**lbs/hp-hr**	**lbs/hp-hr**	**lbs/hp-hr**	**lbs/hp-hr**
Type	**HP**	**CO**	**VOC**	**NOx**	**SOx**	**PM10**
Bore/Drill Rigs/Pile Drivers	217.7	0.001400	0.000400	0.004700	0.000008	0.000200
Cement Mixers	11	0.003800	0.001400	0.006500	0.000009	0.000400
Industrial/Concrete Saws	83.7	0.006400	0.002500	0.006100	0.000008	0.000600
Cranes	190.4	0.001400	0.000500	0.004900	0.000005	0.000200
Crawler Tractors/Dozers	143.4	0.004300	0.001100	0.008500	0.000008	0.000500
Crushing/Processing Eq.	154.3	0.002500	0.000900	0.010200	0.000011	0.000300
Dump and Tender Trucks	223	0.001300	0.000400	0.002600	0.000004	0.000100
Excavators	180	0.003800	0.000800	0.006400	0.000007	0.000400
Forklifts/Aerial Lifts/Booms	83	0.002100	0.000600	0.003800	0.000004	0.000300
Generators/Compressors	37	0.005800	0.002200	0.006100	0.000008	0.000600
Graders	174	0.002000	0.000700	0.007200	0.000008	0.000300
Off Highway Tractors	255.1	0.004900	0.001300	0.010100	0.000008	0.000600
Off Highway Trucks	417.2	0.001500	0.000500	0.004600	0.000005	0.000200
Other Const. Eq.-Diesel	240.3	0.005900	0.002100	0.005600	0.000007	0.000500
Pavers	131.5	0.004400	0.001400	0.008100	0.000007	0.000700
Paving Eq./Surfacing Eq.	110.9	0.006600	0.002800	0.005300	0.000006	0.000600
Plate Compactors	8	0.001800	0.000300	0.002100	0.000004	0.000100
Rollers/Compactors	113.9	0.003500	0.001000	0.006200	0.000006	0.000500
Rough Terrain Forklifts	94.2	0.004200	0.000900	0.007400	0.000008	0.000400
Rubber Tired Dozers	352.5	0.003500	0.000700	0.006400	0.000005	0.000300
Rubber Tired Loaders	165.3	0.003600	0.000800	0.006600	0.000007	0.000400
Scrapers	313.2	0.002900	0.001000	0.009900	0.000009	0.000400
Signal Boards/Light Sets	118.8	0.002500	0.000500	0.003000	0.000006	0.000100
Skid Steer Loaders	62	0.005000	0.001600	0.004900	0.000007	0.000400
Tractors/Loaders/Backhoes	79.5	0.003000	0.000800	0.004700	0.000005	0.000400
Trenchers	28	0.004000	0.001300	0.007600	0.000006	0.000600
Welders	35	0.002300	0.000700	0.004100	0.000004	0.000400
Other Const. Eq.-Gasoline	0.0	0.003300	0.000900	0.006500	0.000006	0.000400

SCAQMD off-road emissions factor database, website, 12/2006. Load factor adjustments incorporated.
EFs are for equipment inventory year 2010.

	Construction Period Emissions, lbs				
Equip. **Type**	**CO**	**VOC**	**NOx**	**SOx**	**PM10**
Bore/Drill Rigs/Pile Drivers	183	52	614	1	26
Cement Mixers	4	2	7	0	0
Industrial/Concrete Saws	54	21	51	0	5
Cranes	5331	1904	18659	19	762
Crawler Tractors/Dozers	740	189	1463	1	86
Crushing/Processing Eq.	0	0	0	0	0
Dump and Tender Trucks	2609	803	5218	8	201
Excavators	6977	1469	11750	13	734
Forklifts/Aerial Lifts/Booms	3486	996	6308	7	498
Generators/Compressors	5365	2035	5643	7	555

Graders	835	292	3007	3	125
Off Highway Tractors	0	0	0	0	0
Off Highway Trucks	0	0	0	0	0
Other Const. Eq.-Diesel	0	0	0	0	0
Pavers	58	18	107	0	9
Paving Eq./Surfacing Eq.	0	0	0	0	0
Plate Compactors	259	43	302	1	14
Rollers/Compactors	797	228	1412	1	114
Rough Terrain Forklifts	0	0	0	0	0
Rubber Tired Dozers	0	0	0	0	0
Rubber Tired Loaders	0	0	0	0	0
Scrapers	2180	752	7442	7	301
Signal Boards/Light Sets	2673	535	3208	7	107
Skid Steer Loaders	2790	893	2734	4	223
Tractors/Loaders/Backhoes	0	0	0	0	0
Trenchers	0	0	0	0	0
Welders	2013	613	3588	4	350
Other Const. Eq.-Gasoline	2888	788	5688	5	350

Totals	**CO**	**VOC**	**NOx**	**SOx**	**PM10**	**PM2.5**	
lbs per const. period	39241	11631	77200	88	4461	4420.75	
tons per const. period	19.6	5.8	38.6	0.0	2.23	2.21	
Average lbs/day =	54.1	16.0	106.3	0.12	6.14	6.09	
Estimated Maximum lbs/day =	*83.8*	*24.8*	*164.8*	*0.2*	*9.5*	*9.4*	*note 3*
Average lbs/month =	1189.1	352.5	2339.4	2.7	135.18	133.96	
Average tons/year =	7.13	2.11	14.04	0.02	0.81	0.80	

CARB-CEIDARS, Updated Size Fractions for PM Profiles: PM2.5 = 0.991 of PM10 : Diesel Vehicle Exhaust
CO2 EF: CCAR General Protocol, June 2006, for CA-Low Sulfur Diesel combustion.

	CO2
lbs per const period	19243021
tons per const period	9622

Other Assumptions and References:

1. Trench construction times per: Southern Regional Water Pipeline Alliance, 3/08.
   Optimum trench construction progress rate is 80m (260ft) per day.
   Non-optimum trench construction progress rate is 30m (100 ft) per day.
   An average progress of 180 ft/day is used where applicable.
2. Paving speeds can range from 3 to 15 m/min depending on asphalt delivery rates and required compaction thickness.
   A minium paving speed of 3 m/min (10 ft/min or 600 ft/hr) I used where applicable.
   The minimum speed is based upon a 3" compacted layer, 12 ft lane width, with an asphalt delivery rate of ~ 140 tons/hr.
   Ref: Asphalt Paving Speed, Pavement Worktip No. 31, AAPA, 11/2001.
3. Estimation of maximum daily emissions is extremely variable. Some projects provide estimated manpower and equipment use schedules, but even this data usually leads to a wide range of assumptions being made in order to estimate equipment exhaust emissions for a maximum work day. The methodology used in this analysis assumes that the estimated maximum day represents the ratio of the number of pieces of equipment on site on any day during the maximum month as compared to the number of pieces of equipment on site on any day during an average month.

CONSTRUCTION PHASE-Main Project Site Fugitive Dust Emissions

MRI Level 2 Analysis

Acres Subject to Construction Disturbance Activites: 20
Max Acres Subject to Construction Disturbance Activites on any day: 20
Emissions Factor for PM10 Uncontrolled, tons/acre/month: 0.0144
PM2.5 fraction of PM10 (per CARB CEIDARS Profiles): 0.21

Activity Levels: Hrs/Day: 10
Days/Wk: 5
Days/Month: 22
Const Period, Months: 33 — 2.8 years
Const Period, Days: 726

Wet Season Adjustment: (Per AP-42, Section 13.2.2, Figure 13.2.2-1, 12/03)
Mean # days/year with rain >= 0.01 inch: 70
Mean # months/yr with rain >= 0.01 inch: 2.33
Adjusted Const Period, Months: 26.58
Adjusted Const Period, Days: 533.5

Controls for Fugitive Dust:
Proposed watering schedule is every: 2.5 Hours

SCAQMD Mitigation Measures, Table XI-A, 4/07
2.5 hour watering interval yields ~80% control of PM10/PM2.5
Speed control of onsite const traffic to <=15 mph = 44% control
Calculated % control based on mitigations proposed: 89 % control
Conservative control % used for emissions estimates: 89 % control
0.11 release fraction

Emissions: Controlled	PM10	PM2.5
tons/month	0.032	0.007
tons/period	0.842	0.177
Max lbs/day	2.9	0.605

Cut and Fill Data:
Total cu/yds: 43000
10^3 cu/yds: 43
MRI PM10 emissions factor, tons/1000 cu.yds: 0.059
PM10 uncontrolled emissions, tons/period: 2.54
Cut and Fill Activity Period, months: 2.0
Cut and Fill Activity Period, days: 44.0

PM10 Controlled Emissions:	tons/period	0.28
PM2.5 Controlled Emisisons:	tons/period	0.06
PM10 Controlled Emissions:	tons/month	0.14
PM2.5 Controlled Emisisons:	tons/month	0.03
PM10 Controlled Emissions:	max lbs/day	12.7
PM2.5 Controlled Emisisons:	max lbs/day	2.7

Emissions Totals:	**PM10**	**PM2.5**
tons/period	**1.1**	**0.2**
tons/month	**0.2**	**0.0**
max lbs/day	**15.6**	**3.3**

Ref: MRI Report, South Coast AQMD Project No. 95040, March 1996, Level 2 Analysis Procedure.
MRI Report factor of 0.011 tons/acre/month is based on 168 hours per month of const activity.
For an activity rate of 220 hrs/month, the adjusted EF would be 0.0144 tons/acre/month.

CONSTRUCTION PHASE- Laydown Yard plus Offsite Linears

MRI Level 2 Analysis

Acres Subject to Construction Disturbance Activites:		25.3	
Emissions Factor for PM10 Uncontrolled, tons/acre/month:		0.0036	
PM2.5 fraction of PM10 (per CARB CEIDARS Profiles):		0.21	
Activity Levels:	Hrs/Day:	10	
	Days/Wk:	5	
	Days/Month:	22	
	Const Period, Months:	33	2.8 years
	Const Period, Days:	726	
Wet Season Adjustment:	(Per AP-42, Section 13.2.2, Figure 13.2.2-1, 12/03)		
	Mean # days/year with rain >= 0.01 inch:	70	
	Mean # months/yr with rain >= 0.01 inch:	2.33	
	Adjusted Const Period, Months:	26.58	
	Adjusted Const Period, Days:	533.5	
Controls for Fugitive Dust:			
	Proposed watering schedule is every:	2.5	Hours

SCAQMD Mitigation Measures, Table XI-A, 4/07
2.5 hour watering interval yields ~80% control of PM10/PM2.5
Speed control of onsite const traffic to <=15 mph = 44% control

Calculated % control based on watering interval ratio:	89	% control
Conservative control % used for emissions estimates:	89	% control
	0.11	release fraction

Emissions: Controlled	PM10	PM2.5
tons/month	0.010	0.002
tons/period	0.266	0.056
Max lbs/day	0.9	0.191

Cut and Fill Data:

Total cu/yds:		0
10^3 cu/yds:		0
MRI PM10 emissions factor, tons/1000 cu.yds:		0.059
PM10 uncontrolled emissions, tons/period:		0.00
Cut and Fill Activity Period, months:		0.0
Cut and Fill Activity Period, days:		0.0
PM10 Controlled Emissions:	tons/period	0.00
PM2.5 Controlled Emisisons:	tons/period	0.00
PM10 Controlled Emissions:	tons/month	0.00
PM2.5 Controlled Emisisons:	tons/month	0.00
PM10 Controlled Emissions:	max lbs/day	0.0
PM2.5 Controlled Emisisons:	max lbs/day	0.0

Emissions Totals:

	PM10	**PM2.5**
tons/period	**0.266333**	**0.06**
tons/month	**0.010019**	**0.00**
max lbs/day	**0.9**	**0.19**

Ref: MRI Report, South Coast AQMD Project No. 95040, March 1996, Level 2 Analysis Procedure.
MRI Report factor of 0.011 tons/acre/month is based on 168 hours per month of const activity.
For an activity rate of 220 hrs/month, the adjusted EF would be 0.0144 tons/acre/month.
EF of 0.0144 tons/acre/month reduced by 75% to account for emissions from laydown yard surface use

PAVED ROAD FUGITIVE DUST EMISSIONS
(associated with construction traffic)

Length of Paved Road used for/by Construction Access:		0.3	miles, roundtrip distance***
Avg weight of vehicular equipment on road:		4.3	tons (range 2 - 42 tons)
Road surface silt loading factor:		0.28	g/m2 (range 0.03 - 400 g/m2)
Particle size multiplier factors:	PM10	0.023	lb/VMT
	PM2.5	0.0034	lb/VMT
C factors (brake and tire wear):	PM10	0.00047	lb/VMT
	PM2.5	0.00036	lb/VMT
Avg vehicle speed on road:		25	mph (range 10-55 mph)
Number of vehicles per day:		262	
Number of construction work days per month:		22	
	Total vehicles per month:	5764	
Number of construction work months:		26.58	after wet season adjustment*
	Total vehicles per const period:	153207.1	

VMT/day:	78.6
VMT/month:	1729.2
VMT/period:	45962.14

	PM10	PM2.5	
Calc 1	0.207	0.207	
Calc 2	1.334	1.334	
Calc 3	0.006	0.0006	lb/VMT

Emissions	PM10	PM2.5
lbs/day	0.46	0.05
lbs/month	10.19	1.00
lbs/period	270.89	26.69
tons/period	0.14	0.01

Default Silt Load Values for Paved Road Types

Freeway	0.02 g/m2
Arterial	0.036 g/m2
Collector	0.036 g/m2
Local	0.28 g/m2
Rural	1.6 g/m2

* see main const dust site page for this value
EPA, AP-42, Section 13.2.1, March 2006, updated 9/2008.
Allocation of emissions from the project traffic will be based on a 0.3 mile roundtrip adjacent to the project site, with trackout emissions allocated to the remaining 0.11 miles.

CO2e Emissions Estimates

Total CO2 emisisons from diesel combustion:	10034.6	tons/period
Total CO2 emissions from gasoline combustion:	1489.4	tons/period

Approximate methane fraction of CO2 for diesel combustion:	0.000051
Approximate N2O fraction of CO2 for diesel combustion:	0.000032
Approximate methane fraction of CO2 for gasoline combustion:	0.000213
Approximate N2O fraction of CO2 for gasoline combustion:	0.000113

Estimated methane from diesel combustion:	0.511765	tons/period
Estimated N2O from diesel combustion:	0.321107	tons/period
Estimated methane from gasoline combustion:	0.317242	tons/period
Estimated N2O from diesel combustion:	0.168302	tons/period

Estimated methane CO2e from diesel combustion:	10.74706	tons/period
Estimated N2O CO2e from diesel combustion:	99.54323	tons/period
Estimated methane CO2e from gasoline combustion:	6.662086	tons/period
Estimated N2O CO2e from gasoline combustion:	52.17368	tons/period

Total CO2e emissions from construction:	**11693**	**tons/period**
	10524	*metric tons/period*

CCAR General Protocol, June 2006, Version 2.1.
IPCC SAR values for methane and N2O.

Average Vehicle Weight Estimate for Construction Period

Vehicle Type	Weight tons	# Vehicles per day	Frac. of total vehicles
Passenger Cars	2	202	0.771
LD Pickups	3	40	0.153
MD Pickups	4	0	0.000
HD Loaded*	40	10	0.038
HD Unloaded*	20	10	0.038
Buses	0	0	0.000
		262	1.000

Weighted Avg Vehicle Weight, tons : **4.3**

* Ref: Liberty Energy XXIII DEIR, City of Banning, CA., Aspen Environmental Group, June 2008.

CONSTRUCTION PHASE - Trackout Emissions

Paved Road Length (miles):	0.11	estimated roundtrip trackout distance			
Daily # of Vehicles:	262				
Avg Vehicle Weight (tons):	4.3		PM10	PM2.5*	
Total Unadjusted VMT/day	28.8		0.207		
Particle Size Multipliers	PM10		1.334		
lb/VMT	0.023		0.001	0.0001	lb/VMT
C factor, lb/VMT	0.00047		**0.943**	0.1594	**lbs/day**
Road Sfc Silt Loading (g/m^2):	0.28		**0.010**	0.0018	**tons/month**
# of Active Trackout Points:	1		**0.28**	0.0466	**tons/period**
Added Trackout Miles:	PM10				
Trackout VMT/day:	1572		*Default Silt Load Values for Paved Road Types*		
Final Adjusted VMT/day	1601		Freeway	0.02 g/m2	
Final Adjusted VMT/month	35218		Arterial	0.036 g/m2	
Final Adjusted VMT/period	936096		Collector	0.036 g/m2	
Construction days/month:	22.0		Local	0.28 g/m2	
Construction months/period:	26.6		Rural	1.6 g/m2	
Control Applied to Trackout:	Sweeping and Cleaning (Water washing)				
Control Efficiency, %	90	0.9	Release Factor =	0.1	

* PM2.5 fraction of PM10 assumed to be 0.169 (CARB CEIDARS updated fraction values) for paved roads.

EPA, AP-42, Section 13.2.1, Proposed revisions dated 9/2008.
Use silt loading factor from default values for road type if no site specific data is available.
Trackout effects approximately 300 ft of roadway arriving and departing from the site access point.

CONSTRUCTION PHASE - Worker Travel - Emissions

Ref: SFAB, Emfac 2007, V2.3, Nov 2006
On Road Vehicles (1967-2011)
LDP/LDT Weighted Avg Efs

Max # of Workers/Day: 729
Avg # of Workers/Day: 303
Avg Occupancy/Vehicle: 1.5
Round Trips/Day: 202
Avg Roundtrip Distance: 15 miles
VMT/Day: 3030

VMT/Const Period: 2199780

Total Const Days: 726

Emissions Factors (lbs/VMT)

NOx	CO	VOC	SOx	PM10	CO2
0.00081	0.00864	0.00091	0.000001	0.00008	0.96325

Avg. Daily Emissions (lbs)

NOx	**CO**	**VOC**	**SOx**	**PM10**		**PM2.5**
2.454	**26.179**	**2.757**	**0.003**	**0.242**	**2918.648**	**0.242**

Tons per Const Period

0.8909	**9.5030**	**1.0009**	**0.0011**	**0.0880**	**1059.4690**	**0.0878**

It should be noted that these emissions are not necessarily new emissions to the regional air shed. A significant portion of the workers will be derived from the existing work force pool in the urban regional area, and as such these workers would most likely be involved in projects in the area regardless of whether or not the proposed facility is constructed. As such, a major portion of the above estimated emissions would not be considered as additions to the air shed.

CONSTRUCTION PHASE - Truck Delivery and Site Support Vehicle Emissions

Ref: SFAB, Emfac 2007, V2.3, Nov 2006
On-Road Heavy Duty Diesels (1967-2011)

Avg # deliveries/day:	10.0	
Avg Haul Distance (miles)	30	see note below
VMT/Day:	300.0	
Work days/yr:	264	
Total Const Work Days:	726	
Total # of Deliveries:	7260	

	NOx	CO	VOC	SOx	PM10	CO2	PM2.5
Emissions Factors (lbs/vmt)	0.025066	0.007002	0.001418	0.000036	0.000955	3.785	
Daily Emissions (lbs)	**7.520**	**2.101**	**0.425**	**0.011**	**0.287**	**1135.500**	**0.284**
Tons per Const Period	2.730	0.763	0.154	0.004	0.104	412.187	0.103

Site Support Vehicle Emissions

Total # of vehicles:	40
# of Pickups (gas):	36
# of Pickups (diesel):	4
Avg. pickup daily vmt:	30
Total Gas VMT:	1080
Total Diesel VMT:	120

NOx	**CO**	**VOC**	**SOx**	**PM10**	**CO2**			**PM2.5**
0.001108	0.010723	0.001096	0.000001	0.000098	1.096509	lbs/vmt*	gasoline	
0.000039	0.000016	0.000002	0.000011	0.000002	0.008964	lbs/vmt*	diesel	
1.1966	**11.5808**	**1.1837**	**0.0011**	**0.1058**	**1184.2297**	**lbs/day**	**gasoline**	**0.1056283**
0.0047	**0.0019**	**0.0002**	**0.0013**	**0.0002**	**1.0757**	**lbs/day**	**diesel**	**0.0002**
0.4344	4.2038	0.4297	0.0004	0.0384	429.8754	**tons/period**	**gasoline**	0.0383
0.0017	0.0007	0.0001	0.0005	0.0001	0.3905	**tons/period**	**diesel**	0.0001

Ref: SFAB, Emfac 2007, V2.3, Nov 2006
LDTs (gas and diesel), 1967-2011

Avg haul distance: one way distance from site to either Concord or Oakland.
These trucks will not be dedicated to the site, so backhaul distances are not included.

CARB-CEIDARS, Updated Fractions for PM Profiles: PM2.5 = 0.991 of PM10 for Diesel Exhaust, and 0.998 for Gasoline Vehicles.

It should be noted that these emissions are not necessarily new emissions to the regional air shed. A significant portion of the truck services will be derived from the existing regional truck services vehicle pool, and as such these truck emissions would most likely be involved in deliveries in the area regardless of whether or not the proposed facility is constructed. As such, a major portion of the above estimated emissions would not be considered as additions to the air shed.

Table 5.1E-6

```
le     : SFAB-2011
sion   : Emfac2007 V2.3 Nov 1 2006
 Date  : 2009/06/11 18:56:46
n Year: 2011 -- All model years in the range 1967 to 2011 selected
son    : Annual
a      : San Francisco Air Basin Average
 Stat  : Enhanced Interim (2005) -- Using I/M schedule for area 43 San Francisco (SF)
ssions: Tons Per Day
***************************************************************************************************************************************************************************************************************

                                                                                                                                   ---- H e a v y   D u t y   T r u c k s ---
          - - - Light Duty Passenger Cars - - -   - - - - - Light Duty Trucks - - - - -   - - - - - Medium Duty Trucks - - - -   ----- Gasoline Trucks ------     Diesel  Total HD     Urban    Motor-       All
          Non-cat       Cat    Diesel     Total   Non-cat       Cat    Diesel     Total   Non-cat       Cat    Diesel     Total   Non-cat       Cat     Total    Trucks    Trucks     Buses    cycles  Vehicles
***************************************************************************************************************************************************************************************************************
hicles     26455.  2928470.     8330.  2963250.    17192.  1674200.    22426.  1713820.     1679.   388205.    27192.   417076.     2527.    42454.    44981.    69449.   114430.     5034.   166772.  5380380.
T/1000       440.    91371.      183.    91994.      366.    55777.      651.    56795.       34.    14393.     1047.    15475.       24.      981.     1005.     5570.     6574.      614.     1347.   172799.
ips       104043. 18413600.    45008. 18562700.    68871. 10484300.   135670. 10688800.    17539.  3867310.   331753.  4216610.    55913.   626140.   682053.  1314440.  1996490.    20138.   333510. 35818300.
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                                                                                Reactive Organic Gas Emissions
n Exh        3.08      5.06      0.03      8.17      2.61      4.76      0.06      7.43      0.30      1.64      0.25      2.19      0.18      0.84      1.03      3.52      4.54      0.66      4.89     27.88
le Exh       0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.07      0.00      0.08      0.00      0.03      0.04      0.43      0.47      0.00      0.00      0.55
art Ex       0.63      8.87      0.00      9.49      0.41      6.22      0.00      6.62      0.13      2.44      0.00      2.57      0.69      1.19      1.88      0.00      1.88      0.01      0.91     21.49
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal Ex       3.71     13.92      0.03     17.67      3.02     10.97      0.06     14.05      0.43      4.15      0.25      4.83      0.88      2.07      2.95      3.95      6.90      0.67      5.79     49.92

urnal        0.14      1.86      0.00      1.99      0.09      1.18      0.00      1.26      0.00      0.15      0.00      0.15      0.00      0.01      0.01      0.00      0.01      0.00      0.26      3.69
t Soak       0.35      3.69      0.00      4.04      0.23      2.21      0.00      2.44      0.02      0.39      0.00      0.41      0.03      0.03      0.06      0.00      0.06      0.00      0.15      7.10
nning        2.05      9.59      0.00     11.65      0.77     11.33      0.00     12.10      0.08      2.77      0.00      2.85      0.26      0.42      0.68      0.00      0.68      0.01      0.81     28.10
sting        0.08      1.10      0.00      1.19      0.06      0.71      0.00      0.77      0.00      0.10      0.00      0.10      0.00      0.00      0.00      0.00      0.00      0.00      0.13      2.18
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal          6.33     30.17      0.03     36.54      4.17     26.40      0.06     30.63      0.53      7.56      0.25      8.35      1.17      2.53      3.69      3.95      7.65      0.68      7.15     90.99
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                                                                                 Carbon Monoxide Emissions
n Exh       38.69    189.74      0.16    228.59     31.93    182.72      0.45    215.09      5.15     41.76      1.25     48.15      4.80     15.00     19.80     17.60     37.40      4.19     55.68    589.10
le Exh       0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.44      0.03      0.47      0.02      0.20      0.22      1.91      2.13      0.00      0.00      2.60
art Ex       3.46    104.38      0.00    107.84      2.30     82.11      0.00     84.41      0.86     29.67      0.00     30.53      5.20     20.52     25.71      0.00     25.71      0.18      3.80    252.48
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal Ex      42.16    294.11      0.16    336.43     34.23    264.83      0.45    299.51      6.01     71.87      1.27     79.15     10.02     35.72     45.73     19.50     65.24      4.37     59.48    844.18
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                                                                                 Oxides of Nitrogen Emissions
n Exh        2.23     19.32      0.30     21.86      1.81     22.85      1.09     25.74      0.22      6.88      4.91     12.02      0.12      3.75      3.87     65.45     69.32     11.76      1.87    142.57
le Exh       0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.07      0.08      0.00      0.00      0.00      4.36      4.36      0.00      0.00      4.44
art Ex       0.17      6.72      0.00      6.89      0.11      6.13      0.00      6.24      0.02      4.82      0.00      4.84      0.08      2.35      2.43      0.00      2.43      0.02      0.12     20.53
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal Ex       2.40     26.04      0.30     28.74      1.92     28.98      1.09     31.98      0.25     11.71      4.98     16.94      0.21      6.10      6.31     69.81     76.11     11.78      1.98    167.53
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                                                                                Carbon Dioxide Emissions (000)
n Exh        0.25     38.54      0.07     38.87      0.21     29.31      0.25     29.77      0.03     11.08      0.60     11.71      0.02      0.73      0.74     10.29     11.03      1.64      0.22     93.24
le Exh       0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.01      0.00      0.02      0.00      0.01      0.01      0.25      0.26      0.00      0.00      0.28
art Ex       0.02      1.47      0.00      1.49      0.02      1.04      0.00      1.06      0.00      0.37      0.00      0.37      0.01      0.03      0.04      0.00      0.04      0.00      0.02      2.97
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal Ex       0.28     40.01      0.07     40.36      0.23     30.35      0.25     30.83      0.03     11.46      0.60     12.10      0.03      0.76      0.79     10.54     11.33      1.64      0.24     96.49
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                                                                                        PM10 Emissions
n Exh        0.02      1.09      0.02      1.13      0.01      1.30      0.04      1.35      0.00      0.38      0.06      0.44      0.00      0.01      0.01      2.32      2.33      0.19      0.05      5.49
le Exh       0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.06      0.06      0.00      0.00      0.06
art Ex       0.00      0.12      0.00      0.12      0.00      0.13      0.00      0.13      0.00      0.03      0.00      0.03      0.00      0.00      0.00      0.00      0.00      0.00      0.01      0.29
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal Ex       0.02      1.20      0.02      1.24      0.01      1.43      0.04      1.48      0.00      0.41      0.06      0.48      0.00      0.01      0.01      2.38      2.40      0.19      0.05      5.85

reWear       0.00      0.81      0.00      0.81      0.00      0.49      0.01      0.50      0.00      0.14      0.01      0.15      0.00      0.01      0.01      0.15      0.16      0.01      0.01      1.64
akeWr        0.01      1.26      0.00      1.27      0.01      0.77      0.01      0.79      0.00      0.20      0.01      0.21      0.00      0.02      0.02      0.13      0.14      0.01      0.01      2.43
          -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------   -------
tal          0.03      3.27      0.03      3.33      0.02      2.69      0.05      2.77      0.00      0.75      0.09      0.84      0.00      0.04      0.04      2.66      2.70      0.21      0.07      9.92
---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------
ad           0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00      0.00
x            0.00      0.39      0.00      0.39      0.00      0.30      0.00      0.30      0.00      0.11      0.01      0.12      0.00      0.01      0.01      0.10      0.11      0.02      0.00      0.94
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                                                                               Fuel Consumption (000 gallons)
soline      36.35   4148.34      0.00   4184.69     29.67   3153.72      0.00   3183.39      4.26   1186.57      0.00   1190.83      5.10     84.12     89.21      0.00     89.21      7.03     35.91   8691.07
esel         0.00      0.00      6.51      6.51      0.00      0.00     22.46     22.46      0.00      0.00     54.19     54.19      0.00      0.00      0.00    948.85    948.85    142.11      0.00   1174.12

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Table 5.1E-7

EMFAC Composite Emissions Factor Conversion

EMFAC 2007, V2.3, Nov 2006

County:	SFAB (BAAQMD)
Year:	2011
Model Years:	1967-2011

EMFAC Burden Output

		LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
Daily VMT/1000		91371	183	55777	651	14393	1047	1005	5570	614	1347
Daily VMT		91371000	183000	55777000	651000	14393000	1047000	1005000	5570000	614000	1347000
ROG, tpd		36.5	0.04	30.57	0.06	8.1	0.25	3.69	3.95	0.68	7.15
CO, tpd		336.27	0.16	299.05	0.45	77.88	1.27	45.73	19.5	4.37	59.48
NOx, tpd		28.44	0.3	30.89	1.09	11.96	4.98	6.31	69.81	11.78	1.98
CO2, tpd	(x 1000) >	40290	70	30580	250	11500	600	790	10540	1640	240
PM10, tpd		3.3	0.03	2.72	0.05	0.75	0.09	0.04	2.66	0.21	0.07
SOx, tpd		0.001	0.39	0.001	0.3	0.001	0.12	0.01	0.1	0.02	0.001

Composite Efs

	LDP(gas) g/VMT	LDP(diesel) g/VMT	LDT(gas) g/VMT	LDT(diesel) g/VMT	MDT(gas) g/VMT	MDT(diesel) g/VMT	HDT(gas) g/VMT	HDT(diesel) g/VMT	Buses g/VMT	Motorcycles g/VMT
ROG	0.36	0.00	0.50	0.0010	0.51	0.00	3.33	0.64	1.00	4.82
CO	3.34	0.00	4.86	0.0073	4.91	0.01	41.28	3.18	6.46	40.06
NOx	0.28	0.00	0.50	0.0177	0.75	0.05	5.70	11.37	17.40	1.33
CO2	400.02	0.69	497.37	4.0661	724.84	5.96	713.11	1716.64	2423.09	161.64
PM10	0.03	0.00	0.04	0.0008	0.05	0.00	0.04	0.43	0.31	0.05
SOx	0.0000	0.0039	0.0000	0.0049	0.0001	0.0012	0.0090	0.0163	0.0295	0.0007

Composite Efs

	LDP(gas) lb/VMT	LDP(diesel) lb/VMT	LDT(gas) lb/VMT	LDT(diesel) lb/VMT	MDT(gas) lb/VMT	MDT(diesel) lb/VMT	HDT(gas) lb/VMT	HDT(diesel) lb/VMT	Buses lb/VMT	Motorcycles lb/VMT
ROG	0.000799	0.000001	0.001096	0.000002	0.001126	0.000005	0.007343	0.001418	0.002215	0.010616
CO	0.007361	0.000004	0.010723	0.000016	0.010822	0.000028	0.091005	0.007002	0.014235	0.088315
NOx	0.000623	0.000007	0.001108	0.000039	0.001662	0.000109	0.012557	0.025066	0.038371	0.002940
CO2	0.881899	0.001532	1.096509	0.008964	1.597999	0.013133	1.572139	3.784560	5.342020	0.356347
PM10	0.000072	0.000001	0.000098	0.000002	0.000104	0.000002	0.000080	0.000955	0.000684	0.000104
SOx	0.000000	0.000009	0.000000	0.000011	0.000000	0.000003	0.000020	0.000036	0.000065	0.000001

Weighted Avg LDP/LDT Gasoline

	g/VMT	lb/VMT		
			Calc 1	0.379
ROG	0.413	0.00091	Calc 2	0.621
CO	3.917	0.00864		
NOx	0.366	0.00081		
CO2	436.9	0.96325		
PM10	0.037	0.00008		
SOx	0.000	0.00000		

	LDP(gas)	LDP(diesel)	LDT(gas)	LDT(diesel)	MDT(gas)	MDT(diesel)	HDT(gas)	HDT(diesel)	Buses	Motorcycles
Annual VMT	3.34E+10	6.68E+07	2.04E+10	2.38E+08	5.25E+09	3.82E+08	3.67E+08	2.03E+09	2.24E+08	4.92E+08
Daily Fuel Use, 10^3 gal	4184.69	6.51	3183.39	22.46	1190.83	54.19	89.21	948.85	149.14	35.91
Daily Fuel Use, gals	4184690	6510	3183390	22460	1190830	54190	89210	948850	149140	35910
Annual Fuel Use, gals	1.527E+09	2376150	1.162E+09	8197900	434652950	19779350	32561650	346330250	54436100	13107150
Average Miles/gallon	21.8	28.1	17.5	29.0	12.1	19.3	11.3	5.9	4.1	37.5

APPENDIX 5.1F

Evalutation of Best Available Control Technology

Evaluation of Best Available Control Technology

Oakley Generating Station Auxiliary Boiler, Combined Cycle Combustion Turbine, and evaporative condenser BACT Analysis

Section 1 - BACT Analysis Methods and Assumptions

Background

In general, California New Source Review Regulations require a control technology that has been achieved in practice for a class or category of source be required as BACT/LAER for sources in that class or category without considering case-by-case economic impact. (Note: In some cases, economic considerations may be taken into account in establishing a class or category of source.) Additionally, many air districts require other more effective technologies that have not been achieved in practice for a class or category of source if the control is shown to be technologically and economically feasible.

Unlike federal BACT/LAER that only apply to major sources, California requirements apply to a great variety of small and large sources. Therefore, clear identification of the sources that are included in a given class or category for which a BACT/LAER determination is being or has been made is critical to reasonable implementation of BACT/LAER requirements in California. Additionally, it is vitally important to ascertain the availability, reliability, and effectiveness of a control technology before deeming it as having been achieved in practice for a class or category of sources.

Based on CARB guidance, the following criteria should be used in determining whether an emissions unit belongs to a class or category of source for which a control technology has been achieved in practice:

A. Source Size (e.g., rating or capacity): The degree of needed similarity may vary based on the equipment type and size. In general, size thresholds that signify a change in emission producing characteristics of the equipment provide for a reasonable delineation based on size. Generally accepted size designations (e.g., small, medium, and large) for a piece of equipment may also be used in defining a class or category of source. It should be noted that EPA does not consider size in defining a class or category of source.

B. Capacity Factor: Limited use, standby, or seasonal equipment are not usually lumped together with full time equipment in a single class or category.

C. Unique Operational/Technological Issues: Certain operational needs and characteristics can impact the effectiveness of a control technology or process.

Operational or technological needs with demonstrable impact on effectiveness or reliability of basic equipment, operation, process, or control technology that are essential to successful operation of an emission unit and cannot be overcome by other reasonable measures can be used in defining a class or category of source. Also, in certain situations, available pre-existing resources at a facility play a key role in rendering certain control technologies feasible. Requiring similar controls at facilities that do not have the same existing resources may not be advisable.

It should be noted that different BACT/LAER control levels may be established within the same class and category of source for varying operational modes. For instance, for gas turbines BACT/LAER levels during startup/shutdown conditions may differ from BACT/LAER levels under full load conditions.

Achieved in Practice Determinations

For an emission or performance level to be achieved in practice for a class or category of source, it should be commercially available, have demonstrated reliability of operation, and have a documented effectiveness verified by acceptable forms of emission or performance measurement.

A. Commercial Availability: At least one vendor should offer the control technology or equipment able to reach an achieved-in-practice emission limit or performance requirement for regular or full-scale operation within the United States. (On the federal level, determinations made outside of the US should also be considered. These considerations, in some instances, can be very difficult to include due to the lack of an organized clearinghouse for compilation of data.)

B. Reliability in Operation: The control technology or equipment should have operated for a reasonable time period in a manner that would provide an expectation of continued reliability. It is not necessary that the equipment operation be continuous, but that the equipment operate reliably in a manner typical of the class or category of source.

C. Effectiveness: The control technology or equipment should be verified to perform effectively over the range of operation expected for the class or category of source. If the control technology or equipment will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification should be based on a performance test or tests, when possible, or other performance data.

Any control technology listed in a permitting agency's BACT/LAER Clearinghouse must be considered in establishing BACT/LAER requirements for that class or category of source. However, prior to accepting another agency's BACT/LAER determination as having been achieved in practice for a class and category, the permitting agency should verify that the technology has been achieved in practice in accordance with the above guidelines. Existing information should be used to the extent needed to prove that the technology has been achieved in practice.

Technology Transfer

Control technologies previously achieved in practice for a class and category of sources and/or other technologically feasible controls should be considered for transfer to other class or category of sources. Potentially transferable control technologies may be either add-on exhaust stream controls, or process controls and modifications. For the first type, technology transfer should be considered between sources that produce similar exhaust streams. For the second type, technology transfer should be considered between sources with similar processes.

Top-Down BACT Assessment

EPA recommends using a “top-down” approach for determining BACT and LAER. This approach essentially ranks potential control technologies in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in EPA's *New Source Review Workshop Manual*, draft, October 1990, the general methodology of this approach is as follows:

1. Identify potential control technologies, including combinations of control technologies, for each pollutant subject to NSR-PSD review.

2. Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.

3. Rank the remaining technically feasible control technologies in order of control effectiveness.

4. Assume the highest-ranking technically feasible control represents LAER/BACT, unless it can be shown to result in adverse environmental, energy, or economic impacts. LAER determinations do not typically include an economic impact evaluation.

5. Select BACT/LAER.

EPA and State maintained RACT/BACT/LAER Clearinghouses (RBLCs) are considered as principal references for identifying potential control technologies and emission rates used in past permitting of similar sources. These databases were queried for entries since January 2000 involving combustion turbines, auxiliary boilers, and evaproative condensers. The emission rates proposed are consistent with the entries in the various State and EPA databases for past (post-2000) BACT/LAER evaluations, especially those for sources with similar MMBtu/hr and MW ratings.

The "top-down" procedure is followed for the BACT/LAER analyses for the pollutants evaluated in this analysis, with a focus on identifying emission limitations or control technologies that are achieved in practice and technically feasible. The sections following present the BACT/LAER analyses and proposed NO_x, CO, PM_{10}, VOC, and SO_2 limits and controls.

Section 2 - BACT Analysis for the Auxilliary Boiler

The proposed auxiliary boiler at the Oakley Generating station is as follows:

Boiler Parameter	Parameter Rating
Fuel	Natural Gas
Heat Rating	50.6 mmbtu/hr
K lbs steam/hr	~34,000
Maximum daily hours of operation	24
Maximum annual hours of operation	4324
Proposed NOx Controls	Low NOx Burners, 9 ppmvd
Proposed CO Controls	Good Combustion Practices (GCP) , 50 ppmvd
Proposed VOC (POC) Controls	GCP, 5 ppmvd
Proposed $PM_{10/2.5}$ and SOx Controls	Natural Gas/Clean Fuel
$PM_{10/2.5}$ Emission Rate	0.007 lbs/mmbtu (HHV)

The proposed auxiliary boiler emissions as presently quantified are as follows (based on the above ratings and operations data):

Pollutant	**Lbs/hr**	**Lbs/day**	**Tons/yr**
NOx	0.55	13.1	1.19
CO	0.37	8.88	0.79
VOC	0.11	2.54	0.24
SOx	0.14	3.38	0.30
$PM_{10/2.5}$	0.354	8.50	0.77

The table below presents the revised BACT proposal for the auxiliary boiler based upon the data presented in this analysis.

BACT Pollutant	**BACT Limit**	**Proposed-Revised BACT**
NOx (1)	7 ppmvd	Ultra Low NOx Burners w/FGR
CO (1)	10 ppmvd	CO Catalyst or GCP
VOC (2)	5 ppmvd	CO Catalyst, GCP and Sole use of PUC Grade Natural Gas
SOx (2)	0.00277 lb/mmbtu	Sole use of PUC Grade Natural Gas
$PM_{10/2.5}$ (2)	0.007 lb/mmbtu	Sole use of PUC Grade Natural Gas

(1) Revised BACT value.
(2) Non-revised BACT value.

A summary of BACT determinations or BACT requirements for similar sized boilers as derived from several of California’s air districts and the EPA RBLC database are presented below.

Agency	Size Range, mmbtu/hr	NOx BACT	CO BACT	VOC BACT	SOx BACT	PM10/2.5 BACT	Comments
BAAQMD	33.5 - 50	9 – 25 ppm	100 ppm	GCP	Nat Gas	Nat Gas	NOx 9 ppm TFCE NOx 25 ppm AiP
	>50	7 – 9 ppm	10 – 50 ppm	GCP	Nat Gas	Nat Gas	NOx 7 ppm TFCE NOx 9 ppm AiP
SDAPCD	<50	12 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
	50 - 250	5-9 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
SCAQMD	<50	7 – 9 ppm	50 – 100 ppm	3 ppm	Nat Gas	Nat Gas	
	50 - 100	9 ppm	100-400 ppm	Nat Gas	Nat Gas	Nat Gas	
SJVUAPCD	<100	9 – 30 ppm	<400 ppm	.003 lb/mmbtu	Nat Gas	Nat Gas	
	100-200	9 – 15 ppm	ND	Nat Gas	Nat Gas	Nat Gas	
EPA RBLC*	20 - 100	7 (9) – 300 ppm	10 – 400 ppm	0.02 – 0.002 lb/mmbtu	Nat Gas	Nat Gas	7 ppm NOx TFCE 9 ppm NOx AiP

ppm = values at at 3% O2 (dry) unless otherwise stated
TFCE = technologically feasible/cost effective
AiP = achived in practice
GCP = good combustion practices
ND = not determined or no data
*RBLC search criteria (boilers only, firing natural gas, 20-100 mmbtu hr, Process code 13.310)

Analysis of Control Requirements for Nitrogen Oxides

Identify Potential Control Technologies

The baseline NO_x emission rate for this analysis is considered to be 0.10 lb/MMBtu for the boiler, based on the applicable New Source Performance Standards (40 CFR Part 60, Subpart Db). It should be noted that the proposed aux boiler is actually a Subpart Dc unit, but Subpart Dc does not specify NOx (or other pollutant) emission rates for natural gas fired units. This emission rate provides a comparison for the evaluation of control effectiveness and feasibility. The maximum degree of control, which results in the lowest NO_x emission rate, is a combination of low-NO_x burners (LNB) in conjunction with selective catalytic reduction (SCR). Note that as an auxiliary boiler, the operation of the boiler will be limited to 4324 hours/year.

As with other combustion sources, NO_x emissions from boilers can be reduced by combustion controls and post-combustion flue gas treatment. Combustion controls include low-NO_x burners and other combustion modifications, which act to reduce the formation of NO_x during the combustion process. Post-combustion controls remove NO_x from the exhaust stream after it is generated. Potential NO_x control technologies for the boiler include the following:

- Low-NO_x burners (LNB)
- Flue gas recirculation (FGR)
- LNB and FGR
- $SCONO_x$
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)

Evaluate Control Technologies for Technical Feasibility

The performance and technical feasibility of the NO_x controls listed above are discussed separately. Combustion controls are discussed first, and a discussion of the post-combustion controls SCR and SNCR follows. The proposed boiler will be fired with only natural gas and be well-maintained and operated with good combustion practices, thus these control options are not discussed separately below.

- **Low-NO_x Burners (including Ultra Low-NOx Burners)**

Low-NO_x burners (LNB) and ULNBs have been developed over the last few decades by applying combustion modifications to "conventional" burners. Low-NO_x burners are very common and there are many variations available from numerous manufacturers. A LNB is a packaged assembly that uses staged combustion techniques to reduce the formation of thermal NO_x. The purposes of LNB are to reduce the amount of oxygen in critical NO_x formation zones, to modify the introduction of air and fuel so that the rate of mixing is slowed, and to reduce the amount of fuel burned at the peak flame temperature. There are two basic types of LNB, air-stage and fuel-staged. Both types of LNB achieve the above objectives, thus, emissions are reduced when compared with conventional burners.

- **Flue Gas Recirculation**

As the name implies, with FGR a portion of the flue gas is recirculated and mixed with the combustion air supply. For new boiler installations, this is usually accomplished with a larger forced draft fan, as compared to that required without FGR. The objective of FGR is to lower the amount of oxygen available to react with nitrogen and reduce the flame temperature, both of which reduce the formation of NO_x. One drawback to FGR is that efficiency is somewhat reduced due to the additional power requirements of the larger fan. The addition of FGR to a LNB assembly can result in further reductions in thermal NO_x formation.

- **$SCONO_x$ for Boilers**

$SCONO_x$ for boilers, as with $SCONO_x$ for turbines, involves a catalyst system initially produced and marketed by Goal Line Environmental Technologies. Other suppliers and marketers are now supposedly offering the technology. In early 2000, the South Coast AQMD BACT database listed an entry in its BACT determinations for "other technologies" (i.e., those that do not qualify as LAER) from April 2000 for $SCONO_x$ applied to a 4.2 MMBtu/hr boiler at a facility within the SCAQMD. No such listing could be found in the SCAQMD BACT database during this analysis, and the applicant could not find any listings for a SCONOx application on any small auxiliary type boilers.

Data compiled by the Energy Solutions Center (DG Consortium, 2004) indicates the following; "the SCONOX system is a new catalytic reduction technology that has been developed and is currently being made available for natural gas-fired turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO2 and NO2. The NO2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer, EmerChem, guarantees CO emissions of 1 ppm and NOx emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims."

EmeraChem, which is a supplier and licenser of the EMx (SCONOX) technology claims on its website that "EMx is a multi-pollutant technology that significantly reduces NOx, SOx, CO, VOC, and PM for gas-fired turbines to ultra low levels (< 1 ppm for all criteria pollutants). The next generation of SCONOx is a multi-pollutant technology in a single system that significantly reduces NOx, SOx, CO, VOC, and PM for air emission requirements. The U.S. EPA declared this technology "the Lowest Achievable Emission Rate" (LAER) for NOx abatement, establishing the standard against which all future emission reduction means will be measured. EMx is the most effective Ammonia Free Reduction (AFR) technology available today for gas turbine (GT), reciprocating engines (IC), and industrial/utility boilers (IB)." To date, the applicant does not believe that any of these claims have been substantiated. The EmeraChem website is replete with such statements, but lacks any actual technology application data, results, operational histories, etc. In addition, the EmeraChem website clearly states that the application of EMx (SCONOx) on commercial/industrial boilers is a <u>future application</u>. Furthermore, they state that a "pilot" unit showed emissions reductions on the order of 95%. Unfortunately, a pilot unit does not establish "achieved in practice".

In the above sections of this analysis a discussion was presented of the criteria used for determining whether a control is achieved in practice. Commercial availability for boiler applications requires that a commercial guarantee is available from the vendor. Given that this technology <u>may</u> have only been applied to one source (which cannot at this time be confirmed), the availability of a commercial guarantee for a much larger boiler is seriously in question. Also, the reliability of $SCONO_x$ on a larger boiler has not been demonstrated. Thus, sufficient data to evaluate the reliability of $SCONO_x$ has not been generated. Also, the effectiveness of $SCONO_x$ on a large boiler has not been demonstrated. As a result of these factors, this control is not considered technically feasible for the proposed boiler.

- **Selective Catalytic Reduction**

Selective catalytic reduction is a post-combustion flue gas treatment in which NO_x is reduced to nitrogen and water by injecting ammonia in the presence of a catalyst. The ammonia can be used in either the anhydrous or aqueous form. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit.

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation, if the catalyst is exposed to excessive temperatures over a prolonged period of time, or from chemical poisoning.

SCR has been used extensively on combustion turbines and to a somewhat lesser extent with boilers. The desired level of NO_x control is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesirable increased levels of unreacted ammonia, called ammonia slip.

- **Selective Non-catalytic Reduction**

SNCR is another post-combustion technology where NO_x is reduced by injecting ammonia or urea into a high-temperature region in the boiler exhaust gas path, without the influence of a catalyst. The SNCR technology requires gas temperatures in the range of 1200° to 2000°F. SNCR has been used extensively on boiler applications where consist fuel quality and firing rates can be maintained.

Based on the information in this section, the following NO_x control technologies are considered technologically feasible for the proposed boiler:

- Low-NO_x burners (LNB)
- Flue gas recirculation (FGR)
- LNB with FGR
- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR).

Rank Technically Feasible Control Technologies by Control Effectiveness

The technically feasible control technologies listed above are ranked by NO_x control effectiveness in the traditional “top-down” format in the table below.

NO_x Control Technologies Ranked by Effectiveness

NO_x Control Alternative	Available?	Technically Feasible?	NO_x Emission Reduction (%)
SCR	Yes	Yes	90
SCONOx	Yes	No	90
LNB with FGR	Yes	Yes	70-90
LNB	Yes	Yes	40-85
FGR	Yes	Yes	40-70
SNCR	Yes	Yes	35-80

Evaluate Most Effective Controls for BACT

For boilers such as the one proposed, low-NO_x burners have become standard. In addition, from Table 1 the highest level of emission control is provided by SCR. The proposed auxiliary boiler will only operate 4,324 hours/year, however, the applicant is proposing to use ultra low-NO_x burners and FGR. The applicant has chosen a combination of technologies which results in equivalent emissions at the highest level of control, thus, the other control technologies are not discussed further. The revised proposed emission rate is 7 ppmvd @ 3% O_2.

Notwithstanding the above, the Applicant considered the application of SCR in addition to the BACT technologies proposed above. Data from the EPA RBLC as well as data from the South Coast AQMD BACT database were examined and noted the following:

- SCR applications on similar sized boilers resulted in NOx levels ranging from 3 to 7 ppmv at 3% O_2. With average NOx levels on the order of 3+ ppmv at 3% O_2.
- Several BACT cost analyses* were reviewed which showed that SCR capital costs ranged from as low as $3900/mmbtu-hr to as high as $10,000/mmbtu-hr (based on the heat rate of the unit in terms of mmbtu/hr).
- Data presented in the BACT analysis prepared for the Duke Energy Cliffside Unit 6/7 auxiliary boiler was used to represent the average capital cost for SCR on small auxiliary boilers. Using the data from this analysis and incorporating a slight cost increase to account for the period difference, i.e., 9/06 to 3/10, resulted in an approximate SCR capital cost for the OGS aux boiler of $227,000.00.
- The anticipated reduction in NOx emissions was estimated to be from 7 to 3 ppmv.
- The annual incremental reduction in NOx emissions with the addition of SCR is approximately 0.53 tons per year.
- The annual average cost control effectiveness is ~$241,000 per ton reduced. This cost is extremely high and well above any of the know cost effectiveness values used by any California air agency. (The cost analysis spreadsheet is attached.)

Based on the above, SCR is not an incrementally cost effective add-on control for the proposed small aux boiler already proposed with ULNBs and FGR.

**NCDAQ, Duke Cliffside Unit 6/7 Aux Boiler Top-Down BACT Analysis, ENSR, 9/06.*
**ETEC, Cutting SCR Cost for NOx Control, www.etecinc.net.*

Select BACT

The applicant has chosen to apply ultra low-NO_x burners and FGR for the proposed auxiliary boiler. From the "top-down" analysis, this represents an equivalent level to the highest level of control for NO_x. This level of control is consistent with the control technologies listed in the RBLC, and in some cases exceeds the level of control for some recently permitted boilers. The proposed emission rate of 7 ppmvd @ 3% O_2 is also consistent with the lowest rates given in the RBLC. There is one entry in the RBLC for a NOx level less than 9 ppmvd @ 3% O_2, i.e., 7 ppm which is applied to a unit rated at 21 mmbtu/hr equipped with SCR.

Analysis of Control Requirements for Carbon Monoxide

Identify Potential Control Technologies

Carbon monoxide (CO) is a product of incomplete combustion. CO formation in a boiler is limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer burner designs and control systems limits the impact of fuel staging on CO emissions.

The applicable NSPS does not contain requirements for CO, thus, there is no real baseline emission rate. Based on a review of the information provided in the RBLC database and knowledge related to the control of CO emissions from combustion sources, the following CO control approaches were identified:

- CO oxidation catalyst
- $SCONO_X$
- Good combustion control

Evaluate Control Technologies for Technical Feasibility

Oxidation catalysts have previously been applied to natural gas-fired boilers located in CO nonattainment areas, although not to the same extent as turbines. The catalyst lowers the activation energy for the oxidation of CO to CO_2 so that CO in the exhaust gas is converted to CO_2. There are numerous suppliers of oxidation catalyst systems, and as such this technology has been applied to natural gas-fired boilers of all sizes and is considered a demonstrated technology.

The $SCONO_X$ process for boilers was previously discussed as part of the NO_X BACT analysis; it is used to control both NO_x and CO. This control technology has not been achieved in practice and is not considered technically feasible for the proposed boiler.

Good combustion control, as the name infers, is based upon maintaining good mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. This technology is technically feasible and is the most commonly used technology to control CO emissions. In fact, combustion control/design coupled with a CO catalyst, is the most stringent control technology listed in the RBLC for boilers.

Rank Technically Feasible Control Technologies by Control Effectiveness

The two technically feasible control technologies for CO are an oxidation catalyst and good combustion controls. Good combustion control is generally considered the baseline control technology for CO emissions. Thus, an oxidation catalyst, which is an add-on control technology, is considered the most stringent level of control for CO.

Evaluate Most Effective Controls for BACT

For boilers such as the one proposed, good combustion practices/design are considered standard. Thus, an oxidation catalyst provides the highest level of emission control. The proposed auxiliary boiler will only operate 4,324 hours/year, however, the applicant is proposing to meet the 10 ppm BACT limit with or with either an oxidation catalyst or by utilizing good combustion design. Based upon both options, the applicant has chosen the most stringent control technology.

Select BACT

The applicant has chosen to apply good combustion design or an oxidation catalyst for the proposed auxiliary boiler. From the “top-down” analysis, either represents the highest level of control for CO. This level of control meets or exceeds the level of control technologies listed in the RBLC for boilers. The proposed emission rate of 10 ppmvd @ 3% O_2 is also consistent with the lowest rates given in the RBLC.

Analysis of Control Requirements for PM_{10}

PM_{10} is a Clean Air Act regulated pollutant defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as filterable and condensable PM. As presented in the turbine section, the amount of both filterable and condensable PM_{10} emissions from natural gas-fired combustion sources should be very small relative to the total exhaust flow. In addition, PM emissions from add-on control devices are typically higher than from uncontrolled natural gas-fired combustion units. Therefore, add-on PM_{10} controls do not make practical sense and are not considered feasible for utility natural gas-fired aux boilers.

Permit data from EPA's RBLC database beginning with January 1990 were searched for PM and PM_{10} BACT decisions and corresponding limit. In particular, data listed for similarly sized natural gas-fired boilers were reviewed in detail. Review of the RBLC database indicates PM/PM_{10} limits in the range of 0.001 – 5.0 lb/MMBtu. The PM_{10} emission rate for the proposed boiler is at the lower end of the range, at approximately 0.007 lb/MMBtu. As noted before, it is difficult to make a direct comparison to the results in the RBLC because it is unclear as to whether the emission rate contained in the database includes both condensable and filterable PM.

In conclusion, because the proposed boiler will fire clean burning natural gas, and its combustion controls will be state-of-the-art, add-on controls are not considered feasible. Particulate emissions from the proposed unit will be controlled via proper design, operation, and maintenance. With respect to combustion controls, there are no significant toxic emissions, economic, energy, or environmental impacts.

Analysis of Control Requirements for VOC

This section presents the BACT analysis for VOC for the proposed natural gas-fired aux boiler. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. The proposed boiler incorporates state-of-the-art combustion technology and is designed to achieve high combustion efficiencies. Additionally, the recombination of products of incomplete combustion is unlikely in well-controlled boilers because the conditions required for recombination are not present. As a result, the proposed boiler has a very low expected VOC emission rate.

Based on a review of the information provided in the RBLC database and knowledge related to the control of VOC emissions from combustion sources, and taking into account technology transfer from other combustion sources, the following VOC control approaches were identified:

- Thermal oxidation,
- Catalytic oxidation, and
- Good combustion design and operation.

Thermal oxidizers are used for combustion systems where VOC rates are high, such as waste incinerators. The thermal oxidizers for these types of sources are in the form of secondary combustion chambers and afterburners and are inherent to the combustion system's design. The VOC emissions from these types of sources are much higher because they combust fuels that are heterogeneous in nature and as a result it is difficult, if not impossible, to maintain the uniform time, temperature, and turbulence needed to ensure complete combustion. Thermal oxidation systems work by raising the VOC containing stream to the combustion temperature to allow the combustion process sufficient time to reach completion. The controlled VOC rates from these systems are still higher than those being proposed for this project without VOC control. Also, because thermal oxidizers combust fuel, a significant amount of NO_x emission can be generated. As such, thermal oxidizers are not considered further in this anlaysis.

Oxidation catalysts have traditionally been applied to the control of CO emissions from clean fuel fired combustion sources located in CO nonattainment areas. As discussed previously, this technology uses precious metal based catalysts to promote the oxidation of CO and unburned hydocarbon (of which a portion is VOC) to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature.

Good combustion design and operation is the primary approach used to control VOC emissions from combustion sources. The VOC controls, inherent in the design and operation of a unit, include the use of clean fuels such as natural gas, and advanced process controls to ensure complete combustion and the best fuel efficiency. The proposed boiler will be 100% natural gas-fired and is designed with state-of-the-art combustion controls to maximize conversion of the natural gas to CO_2, and minimize the production of VOC and CO.

An oxidation catalyst is being proposed to control CO emissions, and such systems can also achieve VOC reduction. The proposed VOC emission rate is 5 ppmvd @ 3% O_2 (0.0021 lbs/mmbtu), which is consistent with low end values from the RBLC for similar-sized boilers and represents BACT for VOC.

Analysis of Control Requirements for SO_2

The new boiler will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., scrubbers) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the achievable emission reduction is far too small for this option to be cost-effective. Also, the proposed emission rate of 2.83 lb/MMscf (~0.00277 lb/MMbtu) is consistent with the lowest emission rates listed in the RBLC.

Cost Effectiveness and Other Impacts

Pursuant to the NSR/PSD Workshop Manual (10/99, Chapter B, page B.8) the applicant has chosen BACT limits which are equivalent to the top control alternatives, and as such is not required to provide cost and other detailed information in regard to other control options. Based on the options chosen, the applicant is not aware of any additional toxics, energy, or other environmental media impacts that would result from the chosen BACT options.

Section 3 - BACT Analysis for the Combustion Turbines

Analysis of Control Requirements for Nitrogen Oxides

The proposed turbines/HRSGs at the Oakley Generating station is as follows:

Turbine/HRSG Parameter	Parameter Rating
Fuel	Natural Gas
Heat Rating	2150 mmbtu/hr (each)
K lbs steam/hr	643
Maximum daily hours of operation	24
Maximum annual hours of operation	8449
Proposed NOx Controls	DLN with SCR
Proposed CO Controls	CO Oxidation Catalsyt
Proposed VOC (POC) Controls	CO Oxidation Catalyst/Natural Gas
Proposed $PM_{10/2.5}$ and SOx Controls	Natural Gas/Clean Fuel

The proposed turbine/HRSG emissions as presently quantified are as follows (based on the above ratings and operations data): (**per turbine/HRSG** basis, steady state operation, the HRSG's are not equipped with duct firing)

Pollutant	Lbs/hr	Lbs/day	Tons/yr[1]
NOx	15.52	372.48	49.3
CO	9.45	226.8	49.0
VOC	2.71	65.04	14.6
SOx	6.00	144.0	6.3
$PM_{10/2.5}$	9.0	216.0	38.1

[1] All annual emissions assume annual operational profile with startup/shutdowns.

The table below presents the revised BACT proposal for the turbines/HRSGs based upon the data presented in this analysis.

BACT Pollutant	BACT Limit	Proposed-Revised BACT
NOx[1]	2.0 ppmvd	Dry LNBs with SCR
CO[1]	2.0 ppmvd	CO Catalyst
VOC	1.0 ppmvd	CO Catalyst and Sole use of PUC Grade Natural Gas
SOx[2]	<=0.00281 lbs/MMBtu	Sole use of PUC Grade Natural Gas
$PM_{10/2.5}$	9.0 lb/hr	Sole use of PUC Grade Natural Gas

[1] Annual NO_x emissions are based on 1.5 ppmvd and annual CO based on 1.0 ppmvd.
[2] Annual SO_x is based on 0.25 gr/100 scf (1.5 lb/hr) while short term is based on 1.0 gr/100scf (6 lb/hr).

Identify Potential Control Technologies

The baseline NO_x emission rates for this analysis use the turbine supplier guarantee of 9 ppmvd @ 15 percent O_2 for the combustion turbines, i.e., turbines with DLN combustors. These emission rates provide a comparison for the evaluation of control effectiveness and feasibility. The maximum degree of control, which results in the lowest NO_x emission rate, is a combination of dry low-NO_x combustors (DLN) with either selective catalytic reduction (SCR) or SCONOx for the turbines.

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment. Combustion modifications for turbines include both wet and dry combustion controls. Wet and dry combustion controls act to reduce the formation of NO_x during the combustion process, while post-combustion controls remove NO_x from the exhaust stream after it is generated. Thus, potential NO_x BACT for the combustion turbines and (with or without duct burners) includes the following:

- Dry low-NO_x combustor design
- Catalytic combustors (e.g., XONON)
- Selective catalytic reduction (SCR)
- SCONOx

Evaluate Control Technologies for Technical Feasibility

The performance and technical feasibility of each “category” of NO_x controls listed above are discussed separately. A detailed discussion of post-combustion controls, which can control emissions from the combustion turbines, follows.

Dry Combustion Controls and Dry Low-NOx Combustors

Dry combustion controls reduce NO_x emissions without wet injection systems. Combustion modifications to reduce NO_x formation include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses additional excess air (greater than stoichiometric air-to-fuel ratio) to cool the flame and thus reduce thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine hot section. The rate of thermal NO_x formation is reduced because the combustion gases are at higher temperatures for a shorter time. The principle behind lean premixed combustion is to premix the fuel and air prior to combustion in order to provide a homogeneous air/fuel mixture, which acts to reduce the combustion temperatures and thus thermal NO_x. Rich/lean combustion uses a fuel-rich primary stage, quenching, and then a fuel-lean secondary stage to reduce NO_x formation, however, this type of control is currently not very common.

Currently, the most widely used combustion controls are dry low-NO_x (DLN) combustors, which use lean premixed combustion to reduce the formation of thermal NO_x. Prior to the development of premix based dry-low NO_X combustors, fuel and air were injected separately into the turbine's combustor section where oxygen in the combustion air needed to support the combustion process diffused to the flame front located at the combustor's fuel burner. Simply put, the combustion occurred in a diffusion flame similar to that of a Bunsen burner. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures. The dry-low NO_X combustion process works to reduce the amount of thermal NO_X that is formed by lowering the overall flame temperature within the turbine combustor by premixing the fuel and air at controlled stoichiometric ratios prior to combustion.

DLN combustion is effective in achieving NO_x emission levels comparable to the levels achieved using wet injection without the need for large volumes of purified water or steam. An increase in CO emissions can result from lower NO_x emission rates (in the range of 9 ppmv). However, negligible increases in CO are associated with controlled NO_x emission rates around 25 ppmv (the level for the proposed turbines before subsequent control). Thus, the increases in CO and VOC emissions that result from wet injection technology (not considered BACT) are not a factor with such DLN systems. Several turbine vendors have developed DLN systems for their turbines, therefore this technology is considered technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in Santa Clara, California. Commercial availability of the technology for a 200 MW GE Frame 7 natural gas-fired turbine was recently announced. The technology has also been announced as commercially available for some models of small turbines (around 10 MW or lower).

The combustor used in the Santa Clara demonstration engine is generally comparable in size to that used in GE Frame 7F engines. The technology has not been announced commercially for the engines proposed for this project, thus a commercial quotation for the use of XONON is not available from the supplier, Catalytica Corporation. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time. Furthermore, in 2001, GE indicated to the developers of the Pastoria Energy Project in California, that XONON technology for large combustion turbines such as the 7FA, would not be available for another 5 to 7 years. In the fourth quarter of 2002, Catalytica Corporation announced its first commercial operation of a catalytic combustion system on a 1.4 MW Kawasaki turbine. We conclude, that scale up of the system for turbines such as those proposed for OGS, may still be several years into the future. Consequently, catalytic combustion controls are not considered commercially available for this project's turbines and are not discussed further.

Post-Combustion Controls

SCR—The SCR process is a post-combustion control technology in which injected ammonia reacts with NO_X in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_X emission reduction is a function of the catalyst volume, ammonia-to-NO_X (NH_3/NO_X) ratio, and temperature (450 F to 850 F typical range dependent upon type of catalyst). For a given catalyst volume, higher NH_3/NO_X ratios can be used to achieve higher NO_X emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds of arsenic, sulfur, potassium, sodium, and calcium. In applications where natural gas is fired, a catalyst life of 5 to 7 years has been demonstrated.

SCR has been demonstrated effective at numerous installations throughout the United States. Typically, SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines can be controlled (although no duct burners are proposed for OGS). SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control in excess of 90 percent can be achieved.

SNCR—SNCR is another post-combustion technology where NO_x is reduced by injecting ammonia or urea into a high-temperature region, without the influence of a catalyst. The SNCR technology requires gas temperatures in the range of 1200° to 2000°F. The exhaust temperature for the proposed turbines ranges from 1030° to 1135°F, which is below the minimum SNCR operating temperature. Thus, some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations. SNCR is most commonly used with boilers, and there are no entries in the RBLC indicating the use of SNCR for turbines. SNCR is considered technologically infeasible for this project due to the temperature considerations. However, even if SNCR were technically feasible, it would not be able to achieve NO_x reductions comparable to SCR.

NSCR—NSCR uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. Typically, NSCR is used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. Consequently, NSCR is not technologically feasible for this project.

SCONOx—The SCONOx system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_X and CO. SCONOx is a relatively new system originally designed and marketed by Goal Line Environmental Technologies that began commercial operation in California at the Federal Plant owned by the Sunlaw Cogeneration Partners in December 1996. Other supplier/licensers, such as EmeraChem (EMx technology) are now offering the SCONOx technology.

The combustion turbine at the Federal facility was a GE LM-2500 that is approximately 23 MW in size, roughly one-ninth the size of each of the two combustion turbines proposed for this project. The application of the SCONOx system at the Federal Plant is the second-generation of the technology. The first generation was a pilot unit application that operated for ten months at another nearly identical GE LM-2500 based facility, the Growers facility, also owned by Sunlaw Cogeneration Partners. The SCONOx catalyst used at the pilot facility was transported to the Federal facility when the pilot unit was taken out of service.

The SCONOx system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The NO present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of N_2 and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to CO_2 as part of the SCONOx process.

In order for the SCONOx technology to work properly, inlet/outlet dampers must continuously isolate one quarter of the catalyst blocks for regeneration. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration about once every 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst is left open to the flue gas flow. After the isolated portion is regenerated, the next set of dampers must close and isolate the next section of catalyst for regeneration. This cycle is continuously repeated. Assuming a four section catalyst, and regeneration times of 15 minutes per section, results in approximately 35,000 regeneration cycles per year.

At the Federal Plant the regenerative gas was produced from natural gas by processing it through a separate skid mounted processing unit. The resulting regenerative gas is approximately 3 percent nitrogen, 1.5 percent CO_2, and 4 percent H_2, with steam making up the balance. Steam is used to: (1) dilute the regenerative gas hydrogen concentration below the lower explosive level; (2) act as a carrier gas; (3) promote the purging of the catalyst bed of the oxygen containing flue gas; and (4) promote even distribution of the regeneration gas throughout the catalyst bed.

Goal Line tested several methods for producing regeneration gas, including a one step method where steam, natural gas, and air are reacted at 900°F using an auto thermal process. This process failed to produce consistent results and was abandoned. Goal Line stated that in future applications, the regeneration gas will be generated in the HRSG at a temperature of approximately 600 °F. This modified system to produce regeneration gas, and to our knowledge, has not been tested on any commercial applications and as such is not yet demonstrated in practice.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed at the beginning of each regeneration cycle. Obtaining a good seal with the dampers is key to: (1) preventing oxygen in the flue gas from disrupting the regeneration process, and (2) evenly distributing the regeneration gases across the catalyst.

Complete regeneration of the SCONOx catalyst system is dependent upon the proper functioning and sealing of these sets of dampers approximately four times each hour. Incomplete regeneration of the catalyst results in decreased system performance which in-turn results in increased NO_X emissions. Based on an article by Goal Line (Campbell et al, February 1997), probably the most important cause of reduced performance in the pilot unit was poor distribution of regeneration gas over the catalyst. As a result, several design changes were incorporated into the system located at the Federal Plant.

The SCONOx catalyst is susceptible to fouling by small amounts of sulfur in the flue gas. Sulfur causes the catalyst to lose activity. The impact of sulfur is minimized by a sulfur absorption catalyst, called SCOSOx, located upstream of the SCONOx catalyst. First, the SO_2 is oxidized and absorbed on to the catalyst. The SO_3 is then desorbed from the catalyst as part of the SCONOx regeneration process. The resulting byproduct of the regeneration is either H_2S (for systems located in the HRSG where the flue gas temperature is below 450 °F at the catalyst) or SO_2 (for systems located in the HRSG where the flue gas temperature is above 450 °F).

In the case where H_2S is formed, it is converted back to SO_2 using an additional subsystem and directed into the exhaust downstream of the catalyst. In the case where SO_2 is the byproduct, it is directed into the turbine exhaust downstream of the catalyst. For a new construction project, the system would be placed in the HRSG at a point where SO_2 would be the primary product of the SCOSOx system.

According to system literature, the catalyst requires periodic washing at least annually. The “washing” consists of removing the catalyst modules from the unit and submerging each module in a vessel containing potassium carbonate. Thus, the adsorbent portion of the SCONOx process must be revitalized or replaced at least annually. For units the size of the proposed turbines, total required “wash” time could be on the order of seven days per turbine per wash cycle (including the time to allow safe entry to the HRSG). There are three options available for carrying out this washing:

1. To shut down the unit for approximately one week to clean the catalyst. Shut down includes a two-day cooling period prior to personnel entering the HRSG. Unbuttoning and entry into the HRSG. Dismantling of the catalyst support structure to allow the catalyst to be removed. Removal and dipping of the catalyst and then placement back into the HRSG. The actual logistics and design requirements of accomplishing this task on a unit the sizes of the proposed units are not yet known. In addition, this approach has the disadvantage of eliminating the ability to produce power during the outage.

2. Removal of the unit while on-line and replacement with clean catalyst while the other catalyst is washed. This approach is impractical in light of the need to assure that all damper seals maintain 100 percent integrity during the removal. The logistics associated with performing this operation on an application with units the size of the proposed units is also several fold more complicated because of the need to maintain tight damper seals where one side is at operating temperature and the other is at ambient in order to allow worker access. Several safety issues would also have to be overcome. This approach also requires that a spare catalyst set be purchased and stored. Thus, additional storage facilities would also be required.

3. Bring the catalyst off-line only long enough to permit removal of the used catalyst and replacement with a spare catalyst set. The removed catalyst is then washed and prepared for placement back in service at the next wash outage.

Any of the above operations will require several days to shutdown and cool the HRSG and SCOSOx/SCONOx sections to the point that the catalyst can be handled safely. Then each catalyst section will have to be removed, washed, dried, and put back in the HRSG before the units can start-up again.

System literature indicates NO_x emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 90 percent reduction, to 1.0 ppm with no averaging period specified (96 percent reduction). System quotes from ABB Alstom Power for a GT26 turbine (rated at 274 MW) indicated a control efficiency of ~90 percent, i.e., NO_x ppm reductions from 20-25 ppm to 2.0-2.5 ppm. Because it has only been applied at relatively small combustion turbine facilities, there are several long-term operational concerns that exist with the SCONOx system. Data presented in the cost analysis section below indicates that for the three BACT analyses noted, the SCONOx vendor did not quote or state that the system could achieve NOx emissions lower than 2.0 ppmv.

Data obtained recently from the City of Redding (Electric Utility Dept.) Alstom GTX 100 unit (41-43 MW), indicates that the system was permitted at a NOx level of 2.0 ppmvd (Unit 5, Permit #03-TV-02, Condition C.7). Data obtained on this unit for a three (3) year demonstration program indicated the following:

- Numerous maintenance and repairs were required during the demonstration period including such items as damper seal gasket redesign and replacement, new steam reactor replacement, steam heater modifications, need to redesign and replace the regeneration distribution plate, install a

larger sulfur filter on the steam reformer, implementation of a revised regeneration purge cycle, and addition of a 2nd layer of SOx catalyst.
- Upgrading of the SCONOx regeneration gas valves to Class 6 type.
- Washing of the SCONOx catalyst 11 times (far in excess of the supplier stated wash cycle).
- Operations data on this unit shows that it rarely operated above the 60% load level, but yet had numerous periods when it exceeded NOx levels of both 2.0 and 2.5 ppmvd.
- According to Shasta County AQMD staff, the SCONOx system has to be pushed very hard to achieve NOx levels below 2.0 ppmvd.

Although technical concerns exist, the SCONOx system will be considered technologically feasible for the purposes of this analysis. Thus, based on the information in this section, the following NO_x control technologies are technologically feasible for the proposed project:

- Dry combustion controls and Dry low-NO_x combustors
- SCR
- SCONOx

Rank Technically Feasible Control Technologies by Control Effectiveness

The technically feasible control technologies listed above are ranked by NO_x control effectiveness in the traditional “top-down” format in the table below.

NO_x Control Technologies Ranked by Effectiveness

NO_x Control Alternative	Available?	Technically Feasible?	NO_x Emissions (@ 15 percent O_2)	Environmental Impact	Energy Impacts
Selective Catalytic Reduction[a]	Yes	Yes	90 percent reduction 2.0 ppm	Ammonia slip	Decreased Efficiency
SCONOx	Yes[b]	Yes[c]	90 percent reduction 2.0 ppm	Reduced CO; potential reduction in VOC	Decreased Efficiency
Dry Low-NO_x Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency

[a] Used in conjunction with wet or dry combustion controls.

[b] The availability of commercial guarantees for utility-scale projects is undetermined.

[c] This technology has been used on small (5 MW and 41 MW) gas turbines; it has not been demonstrated on utility-scale gas turbines.

Evaluate Most Effective Controls for BACT

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x combustors, due to the superior emission control performance and increased efficiency. The proposed project plans to use dry low-NO_x combustors for the combustion turbines, thus no further discussion of water injection, steam injection, or dry low-NO_x combustors is necessary.

The level of NO_x control for SCR and SCONOx is essentially equivalent. However, the SCONOx process is much more complex both chemically as well as mechanically than the SCR technology. The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice, the cost-effectiveness in achieving these levels, and secondary environmental impacts.

The following table compares the two processes. The SCR catalyst needs to be located in the appropriate section of the HRSG and maintained at the proper temperature. An SCR system also requires ammonia to be injected upstream of the catalyst with good mixing and even distribution. By comparison, the SCONOx process is much more complex in that the catalyst requires continuous regeneration, not just the presence of a reducing agent in the flue gas. Unlike SCR, the regeneration process for SCONOx requires a separate process to generate the regeneration gas and the catalyst must be separated from the flow of hot flue gas, during operation of the unit, for the regeneration process to occur. Thus, the need for the isolation louvers and the ability to remove the SCONOx catalyst for washing.

Comparison of SCR and SCONOx Removal Technologies

	SCR	**SCONOx**	**SCONOx**
Process Parameters	NO_X Reduction	CO Reduction	NO_X Reduction
Catalyst	Yes	Yes	Yes
Reducing agent and equipment	Yes	No	Yes
Mechanical seals, positioners, and valves	No	Yes	Yes
Catalyst replacement	3-7 years	5 years	1st Row 7-10 years 2nd – 3rd Rows 30 years
Catalyst regeneration	NA	NA	At least annually
By products/ wastes	NH_3 slip	None	Potassium solution

Each SCONOx catalyst block also has inlet and outlet piping for the regeneration gas. In order to control flow of the regeneration gases, each inlet and outlet pipe has a set of electronically actuated valves. As such, each catalyst section has several actuators and valves that need to properly function and be maintained. In contrast, the SCR ammonia distribution system requires one automatic ammonia flow control valve and a set of manually adjusted valves used as part of the initial tuning of the ammonia injection grid. As a result, relative to the well-demonstrated application of SCR to natural gas-fired sources, the SCONOx processes may have a lower availability and higher operating and maintenance costs for the following reasons:

- The mechanically complex nature of the isolation louvers and positioners;
- The mechanically complex regeneration gas valving system; and,
- The added catalyst regeneration/replacement step (potassium carbonate solution washing).

<u>Evaluation of Achieved in Practice</u>

<u>Commercial Availability</u>: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

<u>Reliability</u>: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50 percent design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Technology Transfer: BACT is based on what is AIP for a category or class of source. However, EPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust (backend) controls and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Achieved in Practice Criteria Evaluation for SCR

SCR has been achieved in practice at a multitude of gas turbine installations throughout the world (including many sites in California and the US). This technology has also been demonstrated on large gas turbines through stack testing and continuous emissions monitoring systems (CEMS) at numerous facilities. SCR technology has been making continued advances over the past few years, although there are not that many facilities in operation designed to meet low NO_x permit limits of 2.0 ppm. There are numerous facilities operating at higher NO_x concentrations and experience from these facilities has allowed manufacturers to gain a better understanding of operations to optimize NO_x reduction, sizing of catalyst systems, reagent distribution, and process and control systems.

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCR technology to control turbine emissions.

Commercial Availability: There are numerous manufacturers of SCR catalyst systems and standard commercial guarantees are available. Guaranteed NO_x levels in the range of 2 to 3 ppm for turbines are commonly available.

Reliability: There are numerous similar installations operating with SCR control systems throughout the United States. This technology has been available for years and has demonstrated the ability to meet low NO_x emission rates. There has not been evidence of adverse effects on overall plant operations and reliability from SCR system operating at these levels.

Effectiveness: SCR technology has been demonstrated to achieve NO_x levels as low as 2 ppm. Due to system design (SCR inlet NO_x levels in excess of those for which the SCR system was designed that caused tripping from pre-mix to diffusion mode), short-term excursions have resulted in NO_x concentrations above 2 ppm. However, these excursions have not been associated with diminished effectiveness of the SCR system. Consequently, as with most control systems designed to reduce emissions to very low levels, the application of SCR should reflect the potential for infrequent NO_x excursions under specified conditions.

Technology Transfer: SCR has been demonstrated on numerous similar installations, and is therefore not a situation of technology transfer.

From the above discussion, SCR technology is considered to be achieved in practice. The technology is capable of achieving NO_x levels of 2 ppm and lower (in some specific instances). The current BACT guidelines used by EPA Region IX indicate that NO_x levels of 2.0 ppm on a 1 or 3-hour average basis are considered BACT for utility-scale gas turbines (with or without supplemental firing). The achievement of NO_x concentrations at these levels, on either a short term or long-term basis, have been demonstrated in practice at numerous sites. Thus, the proposed NO_x emission rate for the combustion turbines of 2.0 ppm on a 1 or 3-hour average basis with the application of DLN combustors, and SCR meets BACT.

Achieved in Practice Criteria Evaluation for SCONOx

The SCONOx system has only been applied at relatively small combustion turbine facilities (5 MW to 43 MW). As a result, there are several long-term operational concerns that continue to exist with respect to the SCONOx system. The SCONOx isolation louvers are moving parts in the flue gas stream that will require more frequent maintenance than any SCR components. In fact, no other combustion turbine systems or boilers have damper systems that require frequent operation from a fully open to a fully closed position.

Louver and damper systems are subject to mechanical and thermal stresses and strains that result from changes in temperatures associated with startup and shutdown as well as normal fluctuations in operating temperatures during load changes or changes in steam demand. These thermal/mechanical stresses result in operating and maintenance problems that are magnified with increases in scale. It should be noted that the change in placement/position of the SCONOx from the Federal facility location where the operating temperature is 320 °F to the supplier stated preferred, undemonstrated, location where the operating temperature will be 550 to 650 °F will increase the challenges associated with maintaining good seals during regeneration.

Another issue of concern is long-term catalyst availability and pricing. The SCONOx catalyst is a proprietary catalyst produced and available through only a very limited number of supplier/licensers, unlike SCR catalysts that are available through multiple suppliers that guarantee competitive pricing and availability. While supplier/licensers guarantee a catalyst life of three years, this catalyst life has not yet been commercially demonstrated over multiple applications, since only a few small units have been operated over that length of time. It is important to note that although SCR catalysts are now well demonstrated, during the first three years of operation on the initial five combustion turbine applications in the U.S. there were numerous catalyst change outs. Also, vendor guarantees are only good for replacement of the catalyst. The guarantee does not:

- Pay for lost revenues associated with downtime;
- Pay for the cost of any penalties resulting from any exceedence of a permit limit;
- Pay for the cost of removing SCOSOx/SCONOx and replacing it with an SCR system; and,
- Ensure that the catalyst will be replaced until the system works. Subsequent catalyst replacements are at the vendor’s discretion and it is left to the vendor discretion to abandon a particular application at any time.

All of these risks and their associated costs would be borne by the proposed project.

In a past application submitted for a Calpine facility to be located in EPA Region IX, an analysis of available CEMS data for the SCONOx system at the Federal facility was conducted. For the period covering July through December 1997, review of the available SCONOx data indicated that up to 12 exceedences per year could be expected for a 3.0 ppm, 3-hour average limit, even when exceedences related to startups and shutdowns were excluded. According to the analysis, for a combined cycle gas turbine with a limit of 2.0 ppm on a 3-hour average basis (the BACT/LAER levels recommended by several agencies), the 1997 SCONOx data from the Federal site indicate that this limit would be exceeded 44 times per year (excluding exceedences associated with startups and shutdowns).

Data analyzed in previous BACT analyses for the Federal facility from the period of April 1 through December 31, 1999, and more recent data are also consistent with the earlier data. According to the analysis, there were approximately 2,500 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For a 3.0 ppm limit based on a 3-hour averaging period, there were 20 exceedences (for the period April - December).

The analyses conducted show that the SCONOx system at the Federal facility is not capable of maintaining low NO_x levels of 3.0 ppm or less on a continuous basis. Moreover, the more recent data do not indicate improved performance over time.

In addition to performance-related concerns about the SCONOx system, there are several specific concerns regarding applying the SCONOx system to this project. Applying the system on a unit that is several times larger than current known applications would require a major redesign of numerous system components. For example, the dampers at the Federal Plant were ~10 feet wide. The HRSG for this project would be approximately 40-45 feet wide.

A width that is approximately four times greater than that previously demonstrated results in concerns about designing dampers that provide an adequate seal when fully opened and closed during the numerous regeneration cycles required (i.e., as many as 35,000 times per year). This concern is heightened for an application at temperatures greater than those at the Federal Plant. In addition, potential interference between damper actuators and the regeneration gas injection system would need to be resolved, as well as issues on attaining and maintaining cross flow distribution of regeneration gas across a 40-45 foot catalyst section.

In an independent evaluation of SCONOx conducted by Stone & Webster, *Independent Technical Review – SCONOx Technology and Design Review*, dated February 2000, it is reported that the initial operation of the SCONOx system at the second installation – the Genetics Institute turbine facility in Massachusetts – resulted in a rapid loss of performance due to poor operation of the regeneration system. The problem was traced to mechanical deficiencies, such as seal and gasket leakage, and numerous corrective actions were necessary. Further changes to the overall system included adding an external reformer and adding a sulfur filter to remove sulfur from the gas that feeds the external reformer. Moreover, Stone & Webster reports that a number of damper/seal design changes have been proposed by the suppliers/licensers based on results from testing of the system. Similar issues have been confirmed at the Redding Electric Utility Unit 5 facility (see comments above).

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCONOx technology.

Commercial availability: SCONOx is available through only limited vendors (the applicant could only identify one vendor, i.e., EmeraChem) and has been applied to a very limited number of small sized turbines. Due to the lack of information in the public domain, there are still questions regarding whether SCONOx technology is presently available with standard commercial guarantees for NO_x levels as low as 2.0 ppm on large frame turbines such as those proposed for the OGS project. Another concern is whether the guarantee will be passed on by the HRSG vendors.

Thus, numerous questions exist regarding the availability of a commercial guarantee for SCONOx. There are also numerous questions regarding scale-up of a SCONOx system to units of the size proposed for this project, consequently, problems associated with installation and operation have to be anticipated. As previously mentioned, even if a commercial guarantee is available, it does not cover the loss of revenue associated with downtime and the potential need to replace the SCONOx system with a SCR system if the required emission level cannot be achieved.

Reliability: Due to the fact that the SCONOx system has not been installed and operated for an extended period of time on a utility-scale turbine, serious questions exist regarding the reliability of the system on such an installation. As the CEMS data from the Federal facility indicate, there has not been a demonstration of the SCONOx system's ability to meet NO_x levels lower than 3 ppm over an extended period of time without numerous exceedences. There have also been numerous design changes since the original SCONOx installation at the Federal plant. As noted in the Stone & Webster report, there have been problems at the Genetics Institute facility that have also required redesign. Consequently, the system that would be applied to a utility-scale application would also likely require design changes, thus, the reliability of the $SCONO_x$ system is substantially unknown.

Effectiveness: The analysis contained in Calpine's Metcalf Energy Center application demonstrates that the effectiveness of the SCONOx system to meet a 2.0 ppm limit on a consistent basis without exceedences is in question. Also, there have been numerous design changes associated with the SCONOx system and as such it is uncertain as to whether the actual system that would be installed on a larger, utility-scale turbine has been subjected to performance testing. From the available data, if SCONOx technology were to be used to achieve extremely low NO_x levels, it would be necessary to include permit conditions that would allow for the potentially frequent NO_x excursions under certain conditions. (This same issue has been noted at the REU Alstom GTX 100 facility, See Redding Electric Utility comments above.)

Technology Transfer: SCONOx technology has been marketed as being capable of achieving low NO_x levels by SCAQMD and EPA (although the data from the Federal facility does not support this conclusion for an extended period of time, without numerous exceedences). The SCONOx system has not been installed on a utility-scale turbine, and serious technical concerns have been enumerated in this application regarding such a scale-up of the technology. While it is not fair to regard this as technology transfer, it is fair to say that SCR has been installed on a large operating fleet of similar installations and is a more demonstrated technology.

In summary, the evaluation concludes that the SCONOx process is not commercially demonstrated on larger, utility-scale turbines and the economic risks to the project versus SCR are considerable. The significant technical/economic risks are a result of the following:

- No commercial demonstration of the SCONOx catalyst operation/regeneration at the mid-HRSG location proposed by the developers for large combustion turbine units like the proposed units;
- No commercial demonstration of the regeneration gas system proposed by the developers for large combustion turbine units like the proposed units;
- No commercial demonstration of a much larger more complex damper system needed to apply the SCONOx technology to very large CT/HRSG systems (concerns here are related to size, complexity, and placement of a damper system into a higher temperature position of the HRSG (i.e., 650 °F versus 350 °F)); and,
- The additional complexity of the SCONOx technology when compared to SCR. This additional complexity will result in lower project availability and could impact revenue generation.

The cost analysis presented herein was derived from the cost analysis data contained in the following BACT analyses:

- JEA-Greenland Energy Center, Black and Veatch, #149588, September 2008.
- FPL-West County Energy Center, August 2005.
- Satsop Combustion Turbine Project, Phase II, SCA Amendment #4, November 2001.

Each of the above noted BACT analyses were prepared for GE 7FA units, similar to those proposed for the OGS project. In addition, the JEA and Satsop analyses compared the total costs of the proposed SCR/CO Catalyst systems to those of the SCONOx system. The table which follows presents a summary of the cost data from each of the above noted analyses on a per turbine basis.

Parameter	JEA-Greenland	FPL-West County*	Satsop CT
SCR/CO Catalyst Capital Cost	$5,243,000	$2,737,771	$3,146,296
SCR/CO Catalyst Annual Ops Cost	$1,952,000	$1,221,691	$1,727,962
SCONOx Capital Cost	$27,912,000	$26,572,482	$14,297,500
SCONOx Annual Ops Cost	$6,693,000	$5,259,691	$4,757,834

*SCR costs only.

The table below presents a comparison of the average SCR/CO Catalyst versus average SCONOx estimated system capital and annual operating costs.

Summary of Combined NO_x/CO BACT Evaluation Results

Control	Capital Cost*	Annualized Cost*
SCR/CO Catalyst	$4,200,000	$1,800,000
SCONOx	$22,900,000	$5,500,000

* All costs are presented on a per gas turbine/HRSG basis (rounded).

The Applicant believes the average costs above represent valid system costs applicable to the GE 7 FA units proposed for the OGS.

Select BACT

Based on the analysis presented, either SCR or SCONOx is generally considered capable of achieving NO_x levels of 2.0 ppm for combustion turbines. However, technical concerns are associated with the use of SCONOx. BACT for NO_x is considered to be the use of either SCR or SCONOx systems in conjunction with dry low-NO_x combustors to achieve NO_x levels for the combustion turbines of 2.0 ppm on a 1 or 3-hour average basis. The proposed project will not have duct burners in the HRSG, consequently the proposed BACT rate needs not take this supplemental firing into account. Consequently, a NO_x level of 2.0 ppm on a 1 or 3-hour average basis is proposed, which is consistent with the lowest emission rates contained in the RBLCs, and found in other recent permitting approvals for similar sized power plants. Due to the technical concerns related to the use of SCONOx and the increased cost (approximately 4-5 times the cost of a SCR/CO Catalyst system per unit), the project proposes the use of SCR technology to meet this emission rate. Thus, the proposal is consistent with the BACT requirements for NO_x. In addition, it should be noted for the three projects noted above in the cost summary, the SCONOx vendor did not quote system costs, nor did they specify or state that the SCONOx system as proposed would achieve lower NOx values, i.e., lower than the 2.0 to 2.5 ppmv values proposed in the BACT analyses.

The applicant proposes to use SCR technology to meet a NO_x level of 2.0 ppm on a 1 -hour average basis for the combustion turbines with an ammonia slip level of 5 ppm. This proposal is consistent with BACT/LAER requirements and with emission rates found in numerous RBLC databases, as well recent permitting actions for similar sized power plants.

Analysis of Control Requirements for Carbon Monoxide

Identify Potential Control Technologies

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems minimizes the impact of fuel staging on CO emissions.

The applicable NSPS does not contain requirements for CO, thus, there is no real baseline emission rate. For purposes of this analysis, an uncontrolled baseline value for CO was assumed to be 5 ppm per the turbine manufacturer's data. Based on a review of the information provided in the RBLC database and knowledge related to the control of CO emissions from combustion sources, the following CO control approaches were identified:

- CO oxidation catalyst
- SCONOx
- Good combustion control

Evaluate Control Technologies for Technical Feasibility

Oxidation catalysts have previously been applied to natural gas-fired combustion turbines located in CO nonattainment areas, and there are numerous suppliers of oxidation catalyst systems. The catalyst lowers the activation energy for the oxidation of CO to CO_2 so that CO in the exhaust gas is converted to CO_2. For units that include duct firing, the placement of the catalyst is defined by the need to protect it from temperatures in excess of 1100 degrees F. Because the removal efficiency of CO is fairly constant above approximately 550 degrees F, there is only minimal impact to the catalyst's performance associated with placing it further back in the HRSG.

This technology has been applied to natural gas-fired combustion turbines of all sizes, and as such, is considered a demonstrated technology. CO removal efficiencies can vary, and can range from 60-90 percent. The oxidation catalyst is typically a precious metal catalyst, such as platinum. As the basis of control used to evaluate BACT for this application, a uncontrolled emissions rate of 5 ppm at 15 percent O_2 was used, with a controlled rate of 2 ppm representing BACT levels (except for SCONOx as noted below).

The SCONOx process previously discussed as part of the NO_X BACT analysis is used to control both NO_x and CO. The SCONOx system provides for control of CO emissions to levels comparable to that of a conventional oxidizing catalyst. As part of the NO_x BACT discussion, it was noted that SCONOx is currently being applied to a limited number of small turbines (5-43 MW). Based on available literature describing the Federal Plant's operation, a 90 percent removal efficiency is evaluated. Technical concerns were identified in association with application of the technology on a larger combustion turbine, however, this technology will be considered technically feasible for this analysis.

Good combustion practices (GCP), as the name infers, is based upon maintaining good mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. This technology is technically feasible and is the most commonly used technology to control CO emissions. Good combustion control is considered the baseline control technology for CO emissions. Thus, an evaluation is provided for the two most stringent technically feasible control technologies, an oxidation catalyst and SCONOx.

Rank Technically Feasible Control Technologies by Control Effectiveness
Both an oxidation catalyst and SCONOx are considered in this analysis. Control efficiencies for both controls can vary widely. Consequently, the following analysis compares both control systems for potential CO control application.

Evaluate Most Effective Controls for BACT

The addition of a CO oxidation catalyst to reduce outlet emissions to 2 ppmv was evaluated. This emissions level is achievable in practice and can be guaranteed. Note the following: For SCONOx, a CO control level of 4 ppmvd was evaluated as potential BACT. The applicant could not find any data that would indicate that SCONOx could achieve levels below 4.0 ppm and an accompanying VOC level of 1.0 ppmvd as proposed by the applicant. If data cannot be acquired that indicates that SCONOx can achieve a CO level of 2.0 ppmvd and a concurrent VOC level of 1.0 ppmvd, then SCONOx would have to be eliminated from the CO BACT analysis. The BACT evaluation that follows considered the energy, environmental, and economic impacts of the potential differing BACT levels noted above.

Energy Impacts: There is a pressure drop associated with each of the add-on controls that were evaluated. This pressure drop results in a backpressure on the combustion turbine, which in turn increases the heat rate (i.e., decreases the turbine's efficiency). The end result is an energy impact in the form of additional fuel to make the same amount of electricity as well as loss of generating capacity. Based on vendor information the increased backpressure on the turbine associated with oxidation catalyst systems is 1-1.5 inch w.c. The backpressure for a SCONOx system is typically greater. A backpressure of 5 inch w.c. is used for this analysis for SCONOx (vendor quotes range from 4" to 6.3" w.c.). Each inch w.c. of backpressure on the turbine results in a 0.15 percent increase in the heat rate (i.e., Btu/kwh). As a result, there is an increased fuel requirement to generate the same amount of power output. This penalty is included as an annual cost. It should also be noted that the additional fuel firing also results in additional emissions of some pollutants such as NO_x, PM_{10}, and SO_x.

Environmental Impacts: The spent oxidation catalyst is comprised of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of its precious metal content, the catalyst is often recycled by the manufacturer to recover the metals. The SCONOx system providers also take back the catalyst for reconditioning. The effective power reduction due to the pressure drop across the two add-on control technologies increases the emission rate of other criteria pollutants, such as NO_X, on a per unit of power output. The use of natural gas in the catalyst regeneration process for SCONOx will result in release of some natural gas (methane) to the atmosphere due to leakage and venting. As noted above, the SCONOx catalyst also must be regenerated using a 4-step potassium carbonate bath and water rinses. Each module will generate several thousand gallons of wastewater per step. A SCONOx installation for the Project is expected to require the use of ~40-60 modules. Even assuming the low end of only 40 modules, there would be approximately half a million gallons of wastewater produced each year for the two turbine/HRSGs. In addition, production of the regeneration gas requires additional water to generate the steam needed for the process. Such an increase in water consumption and waste discharge associated with SCONOx is a potential concern for the project.

Another concern associated with SCONOx, as discussed in further detail in the NO_x BACT section, is that an installation of the system in the hot section of the HRSG has not been demonstrated to the satisfaction of the HRSG suppliers. HRSG suppliers are not yet willing to offer performance guarantees for their equipment if the $SCONO_x$ system is installed in the hot section of the HRSG.

Economic Impacts: A summary of the capital and annual costs associated with the installation of an oxidation catalyst and SCONOx are presented in the NOx section above. The cost of the oxidation catalyst system includes the catalyst, catalyst housing, HRSG modifications, and balance of plant equipment. The costs presented in the NOx BACT section are also valid for the CO BACT cost analysis since the cost of the combined SCR/CO Catalyst systems were compared to the SCONOx system.

Select BACT

Based on the above discussion, both control technologies evaluated for CO control, an oxidation catalyst and SCONOx, are considered technically feasible and provide comparable reduction efficiencies. Even though the proposed project is located in an attainment area, and controls beyond combustion controls have not typically been required in attainment areas, the project is proposing the use of an oxidation catalyst to meet BACT requirements of 2 ppm (1 or 3 hour average). The use of an oxidation catalyst versus SCONOx is supported by the technical questions associated with SCONOx and the large difference in cost.

Analysis of Control Requirements for PM_{10}

PM_{10} is defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as filterable and condensable PM_{10}. The following discussion explains the formation of both for combustion sources.

For combustion sources, there are three potential sources of filterable PM_{10} emissions: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter for natural gas-fired combustion sources, such as the proposed turbines. In addition, as a precautionary measure to protect the high speed rotating equipment with a combustion turbine, the inlet combustion air is filtered prior to compression and use as combustion air. Also, the potential for soot formation in natural gas-fired turbines is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable PM_{10} originating from the turbine.

There are two sources of condensable PM_{10} for combustion sources: condensable organics that are the result of incomplete combustion and sulfuric acid mist that is found as sulfuric acid dihydrate ($H_2SO_4 \bullet 2H_2O$). For natural gas-fired sources, there should be no condensable organics originating from the source because the main components of natural gas (i.e., methane and ethane) are not condensable at the temperatures found in a Method 202 ice bath (the EPA reference method for measuring condensable PM). Thus, any condensed organics are from the ambient air. The most likely source of condensable PM_{10} from natural gas-fired combustion sources is sulfuric acid dihydrate, which results when sulfur in the fuel and in the ambient air is combusted and then cools.

Appendix M of 40 CFR Part 51 recommends that EPA Reference Methods 201or 201A be used to measure in-stack emissions of PM_{10}. As part of Appendix M, EPA also recognizes that condensible emissions not collected by an in-stack method are also PM_{10} and that these emissions contribute to ambient PM_{10} levels. As a result, to establish source specific contributions of PM_{10}, EPA suggests that PM_{10} measurements include both condensable particulate matter emissions and emissions measured by the in-stack methods. The use of EPA Reference Method 202 is recommended for determining the portion of condensable PM emissions that are PM_{10} from stationary sources.

The Method 201/201A and Method 202 portions of the sample are referred to as the filterable and condensable portions, because the PM_{10} emissions from a source represent the sum of these two measurements. Only the most recent NSR permits issued for turbines require the measurement of both the filterable and condensable portions. Most combustion turbine permits only require measurement of the filterable PM_{10}. Thus, comparison of the proposed PM_{10} emission rate to emission rates in the RBLC can be difficult, because the lower rates may represent only the filterable PM_{10} portion, and not be directly comparable.

Based upon the above discussion, the amount of both filterable and condensable PM_{10} emissions from the natural gas-fired combustion turbines should be very small relative to the total exhaust flow. However, the vendor estimated base load PM_{10} emission rates are 9 lb/hr for the turbines. Vendor data on expected PM_{10} emission rates are designed to allow for the high level of test error inherent in sampling for an extremely small quantity of PM_{10} in a very large exhaust flow. In order to reduce the amount of variability/error, longer sampling times than are normally used by stack testers during compliance testing are required.

Permit data from various RBLC databases beginning with January 2000 were searched for PM and PM_{10} BACT decisions and corresponding limits. In particular, data listed for similarly sized natural gas-fired installations were reviewed in detail. Based on a review of the information provided in the RBLC databases, data gleaned from recent permitting decisions, and a knowledge of combustion source PM and PM_{10} controls, and taking into account technology transfer from other combustion sources, the following PM_{10} control approaches were identified:

- Add-on control technologies including: electrostatic precipitators, baghouses or fabric collectors, and venturi or packed bed scrubbers;
- Combustion turbine lubrication oil exhaust vent coalescers;
- Combustion turbine inlet air evaporative coolers;
- Use of clean (i.e., low ash) and low sulfur fuels such as distillate oil or natural gas; and
- Combustion controls and practices designed to minimize the production of soot.

Add-on controls are used to control particulate emissions from solid fuel (i.e., coal, coke, or waste) and residual oil-fired boilers because of the relatively high level of mineral matter (i.e., ash) in these fuels. There are no known applications of add-on controls for the purpose of controlling PM from distillate oil or natural gas-fired units, because these fuels have little if no ash that would contribute to the formation of PM or PM_{10}. Therefore, add-on PM_{10} controls do not make practical sense and are not considered feasible for natural gas-fired turbines.

Review of the RBLC databases indicates PM/PM_{10} limits in the range of 0.0023 - 0.06 lb/MMBtu. The PM_{10} emission rate for the proposed combined cycle units is toward the lower end of the range, approximately 0.007 lb/MMBtu. As noted before, it is difficult to make a direct comparison to the results in the RBLCs because it is unclear as to whether the emission rate contained in the database includes both condensable and filterable PM_{10}.

The proposed combustion turbines will include inlet air filters, which are required as part of the design to protect the rotating equipment. Inlet air coolers are included on units located in arid regions where high ambient temperatures combined with low relative humidity can sometimes preclude the ability to fire the turbine at full load. To overcome this, an inlet air cooler is placed downstream of the inlet air filters and upstream of the compressor air intake. Combustion air is drawn across a wetted surface (similar to a home humidifier screen) or fogging nozzles spray moisture directly into the inlet air. As a result of these processes, the inlet air is cooled and picks up moisture. These devices clean the ambient air upstream of the source, rather than controlling the emissions generated by the source. Therefore, these devices are not considered further in this analysis.

The proposed combustion turbines are natural gas fired. They are also equipped with state-of-the-art combustion controls to ensure maximum fuel efficiency. As a result, the conversion of fuel carbon to CO_2

will be maximized and the production of carbonaceous particulates minimized. With respect to combustion controls, there are no significant economic, energy, or environmental impacts.
In conclusion, because the combustion turbines will fire clean burning natural gas, and their combustion controls will be state-of-the-art, add-on controls are not considered feasible. Particulate emissions from the proposed combined cycle units will be controlled via proper combustor design, operation, and maintenance, coupled with sole use of natural gas fuel.

The proposed PM10/2.5 emission rate is 9 lb/hr, which is consistent with values for natural gas fuel use, values from the RBLC and district databases, and represents BACT for PM10/2.5.

Analysis of Control Requirements for VOC

This section presents the BACT analysis for the proposed units having a potential to emit VOC (i.e., the combustion turbines). The water circulated through the cooling tower will be noncontact cooling water and no water treatment chemicals containing VOC will be used. Consequently, the cooling tower does not have the potential to emit VOC and therefore has not been evaluated in this analysis.

The proposed combustion turbines are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines incorporate state-of-the-art combustion technology, and are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (~89.6 percent by vol.) and ethane (~5.8 percent by vol.), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100 percent combusted. The high-energy efficiency of turbines and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine systems because the conditions required for recombination are not present.

Based on a review of the information provided in the various RBLC databases, recent permitting decisions, and knowledge related to the control of VOC emissions from combustion sources, and taking into account technology transfer from other combustion sources, the following VOC control approaches were identified:

- Thermal oxidation,
- Catalytic oxidation, and
- Good combustion design and operation.

Thermal oxidizers are used for combustion systems where VOC rates are high, such as waste incinerators. The thermal oxidizers for these types of sources are in the form of secondary combustion chambers and afterburners and are inherent to the combustion system’s design. The VOC emissions from these types of sources are much higher because they combust fuels that are heterogeneous in nature and as a result it is difficult, if not impossible, to maintain the uniform time, temperature, and turbulence needed to ensure complete combustion. Thermal oxidation systems work by raising the VOC containing stream to the combustion temperature to allow the combustion process sufficient time to reach completion. The controlled VOC rates from these systems are still higher than those being proposed for this project without VOC control. Also, because thermal oxidizers combust fuel, a significant amount of NO_x emissions can be generated. As such, thermal oxidizers are not considered further in this analysis.

Oxidation catalysts have traditionally been applied to the control of CO emissions from clean fuel fired combustion sources located in CO nonattainment areas. As discussed previously, this technology uses precious metal based catalysts to promote the oxidation of CO and unburned hydrocarbon (of which a portion is VOC) to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature.

Good combustion design and operation is the primary approach used to control VOC emissions from combustion sources. The VOC controls, inherent in the design and operation of a unit, include the use of clean fuels such as natural gas, and advanced process controls to ensure complete combustion and the best fuel efficiency. The proposed turbines will be 100 percent natural gas-fired and each unit is designed with state-of-the-art combustion controls to maximize conversion of the natural gas to CO_2, and minimize the production of VOC and CO.

An oxidation catalyst is being proposed to control CO emissions, and such systems also achieve VOC reduction. Thus, the highest ranking, technically feasible control technology is being proposed for VOC control.

The proposed VOC emission rate is 1.0 ppmv (1 or 3 hour average), which is consistent with natural gas fuel use, values from the RBLC and district databases, and represents BACT for VOC.

Analysis of Control Requirements for SO_2

The new combustion turbines will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., scrubbers) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the realizable emission reduction is far too small for this option to be cost-effective.

The use of natural gas is proposed as BACT for SO_2. Also, from the RBLC databases, and recent permitting decisions, there is no precedent for use of post-combustion control of SO_2 on combined cycle units firing natural gas.

The proposed short-term SOx emission rate is 0.0028 lb/mmbtu is consistent with the use of natural gas fuel, represent the lower values from the RBLC and district databases, and represents BACT for SOx.

Pursuant to the NSR/PSD Workshop Manual (10/99, Chapter B, page B.8) the applicant has chosen BACT limits which are equivalent to the top control alternatives, and as such is not required to provide cost and other detailed information in regard to other control options. Based on the options chosen, the applicant is not aware of any additional toxics, energy, or other environmental media impacts that would result from the chosen BACT options.

Analysis of Turbine Startup/Shutdown BACT

Each turbine will incorporate General Electric's Rapid Response capability with cold, warm, and hot starts taking shorter time to achieve compliance with normal steady state emission limits than conventional start-ups. Each turbine will also include an unfired HRSG. During periods of plant shutdown, a 50.6 MMBtu/hr auxiliary boiler will be utilized to maintain the plant in a hot-standby condition. Based on the Rapid Response design of the plant, the project startup and shutdown emissions are proposed to represent turbine BACT for startup and shutdown.

Startup and Shutdown BACT Emissions (Per Turbine)

Parameter/Mode	Cold Startup	Hot/Warm Startup	Shutdown
NO_x, lbs/event	96.0	22.0	39.0
CO, lbs/event	360.0	85.0	140.0
POC, lbs/event	67.0	31.0	17.0
PM_{10}, lbs/event	6.8/54.4	2.1	4.5
SO_x, lbs/event	2.9/	0.9	1.9
Event Time, minutes[b]	90 minutes	30 minutes	60 minutes
Maximum Number of Events/Year	25	312	312

Section 4 – BACT Analysis for Wet Evaporative Condenser

The Applicant reviewed the specifications for three major manufacturers of evaporative fluid coolers of the proposed type and size required for the OGS and has been unable to find one that will achieve a drift rate of 0.0005 percent. A drift rate of 0.0005 percent is more typical of coolers found with field-erected cooling towers. The proposed units are much smaller, packaged units that are similar to those that that might be used in a cooling system for a warehouse or office building. The three units that have been considered are:

- SPX Marley MH Evaporative Fluid Cooler—SPX, who provided a similar unit for the Gateway Generating Station, is willing to offer a drift rate of 0.003 percent in a unit sized for the OGS.
- Evapco ATWB Closed Circuit Cooler—Evapco's technical specifications indicate a drift rate of 0.001 percent.
- Baltimore Aircoil Company FXV Closed Circuit Cooling Tower—Baltimore Aircoil does not indicate the drift rate in their technical specifications; however, a company representative indicated that the drift rate is 0.005 percent.

Technical specifications documents for the cooling towers manufactured by each of these three companies can be provided to Staff on request. The Applicant is proposing a drift rate of 0.003 percent, which will allow competitive bidding between at least two manufacturers.

Section 5 – Control Technology Analysis for Greenhouse Gas Emissions for the Oakley Generating Station.

Part A.

The primary basis for the control technology analysis for greenhouse gases (GHG) anticipated to be emitted from the Oakley Generating Station (OGS) facility is the Bay Area Air Quality Management District response to comments on the Russell City Energy Center greenhouse gas assessment (Part B of this submittal). The Part B analysis presents a detailed analysis of the greenhouse gas BACT issues as they pertain to combined cycle combustion turbine electrical generation facilities and miscellaneous support equipment. As such, there is no need to re-evaluate the basic underlying issues.

As proposed, the Oakley Generating Station will be comprised of four major systems that will have the potential to emit greenhouse gases, these are as follows: (1) combustion turbines with non-fired HRSGs, (2) the auxiliary boiler, (3) the fire pump system engine, and (4) the SF_6 electrical breakers.

Combustion Turbine GHG Control Technology Analysis

The Applicant is proposing to comply with limits on the facility's emissions of CO_2, methane (CH_4) and nitrous oxides (N_2O), as calculated in accordance with the methods adopted both by the California Air Resources Board's mandatory reporting rules for greenhouse gas emissions, as well as by the proposed federal mandatory reporting rule. The Applicant believes that, for purposes of assuring consistency with existing reporting regimes for greenhouse gas emissions, the control technology analysis should be aligned with appropriate permit conditions referencing prevailing methods for calculation and inventorying of greenhouse gas emissions. Accordingly, the facility is proposing to demonstrate compliance with the following mass greenhouse gas emissions limits by recording its fuel usage data and application of the specific emissions factors described below. These mass emissions limits include the emissions occurring during transient or partial load operation, including startup and shutdowns, and for baseload generating capacity (without duct firing). The turbine GHG design efficiency is 56%, which is at the upper end of current turbine efficiency values, which range from 51% to 57%.

Averaging Time	Permitted Heat Input* (mmscf)	Permitted Heat Input* (MMBtu - HHV)	CO_2 Metric Tonnes	CH_4 Metric Tonnes	N_20 Metric Tonnes	CO_2E Metric Tonnes
1-Hour	4.208	4300.6	231.94	0.0039	0.00043	232.155
24-Hour	100.978	103,199.5	5565.77	0.0936	0.0103	5570.93
Annual	34,635.3	35,397,276.6	1,918,854	32.28	3.55	1,920,719

*Total for two turbines (assuming 1022 btu/scf HHV)

For CO_2, emissions will be calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu (HHV), as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, the emissions are calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively, and then converted into CO_2e by application of their respective global warming potential of 21 and 310, based upon the Air Resources Board's mandatory reporting rule.

Auxiliary Boiler GHG Control Technology Assessment

The auxiliary boiler will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because, like the turbines, it will combust a hydrocarbon fuel (natural gas). There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis (see Part B).

The auxiliary boiler is proposed to be used for a maximum of 4,324 hours per year. At the rated heat input of the boiler, the annual fuel use would be approximately 214.085 mmscf/year. The boiler would generate estimated CO_2E emissions on the order of 11,724.8 metric tons/year. The Applicant is proposing a BACT limit for the auxiliary boiler of 11,724.8 metric tons/year. The Applicant is proposing to monitor and record the boiler fuel use, and apply the following factors to calculating the annual GHG emissions to show compliance with the above noted annual value: (1) CO_2 at 120,593.5 lbs/mmscf, (2) CH_4 at 0.19842 lbs/mmscf, and (3) N_2O at 0.19842 lbs/mmscf.

Fire Pump System Engine GHG Control Technology Assessment

The emergency diesel fire pump engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel, i.e., low sulfur diesel fuel. There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis (see Part B).

The Applicant therefore concludes that the only achievable technological approach to reducing greenhouse gases from the fire pump engine is to use the most efficient engine that meets the stringent National Fire Protection Association (“NFPA”) standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types, instrumentation and control, and exhaust systems. As there is only one control technology to choose from, application of the 5 steps in the Top-Down control technology analysis results in the selection of that control technology.

The 2100 R.P.M. 400-hp Clarke JW6H-UF40 diesel fire pump engine that the applicant has proposed for use at OGS has a fuel consumption rate of ~20.0 gallons per hour. The Applicant has reviewed fuel-efficiency data for similarly-sized NFPA-20 certified fire pump diesel engines rated at 2100 R.P.M., and has not found any such engines with significantly higher fuel efficiency. The Applicant has therefore concluded that the 20-gal/hr Clarke engine is the one of the most fuel efficient engines available (for use on a fire pump system), and so it qualifies as the best control technology.

The fire pump engine may be used for up to 50 hours per year for reliability testing and maintenance purposes. Use of the engine at 20 gallons of diesel fuel per hour for up to 50 hours per year (1000 gals/year) would result in total greenhouse gas emissions from the fire pump of 9.9 metric tons CO_{2e} per year (based on a factor of 21.7 lb CO_2e/gal) (factor was specified by BAAQMD) . The Applicant will accept a greenhouse gas limit in the permit of 9.9 metric tons per year of CO2e as a limit. The facility will be required to demonstrate compliance with this limit by recording fuel usage and using an emissions factor of 21.7 lb CO_2e/gal to determine resulting CO_2e emissions.

Electrical Circuit Breaker SF_6 GHG Control Technology Assessment

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection should be able to maintain fugitive SF_6 emissions below 0.5% (by weight). The OGS facility will require several breakers with a total inventory of 200 lbs SF_6. At a leak rate of 0.5%, annual SF_6 emissions would be a maximum of 1.0 lbs/year, which would equal approximately 10.3 metric tons CO_2E per year. The Applicant is proposing an annual emissions limit of 10.3 metric tons CO_2e per year, based on a leak rate not to exceed 0.5%, for the final permit.

In addition the Applicant is proposing the use of an alarm system to alert operations staff when a circuit breaker loses 10% of its SF_6. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The facility will also investigate alarms and take any necessary corrective action to address problems.

Facility CO_2e Limit

The Applicant is proposing that the Final Permit for the OGS facility include an annual limit on facility-wide emissions of CO_2e. To account for emissions of CO_2e and assure that they are included in an enforceable permit condition, the Applicant shall limit total facility-wide CO_2e to the amounts emitted by the combined-cycle power plant (combustion turbines), the auxiliary boiler, the emergency standby diesel engine and circuit breakers. This annual limit reflects potential CO_2e emissions as follows:

- Turbines – 1,920,719 mtons CO_2e
- Auxiliary Boiler – 11,725 mtons CO_2e
- Fire Pump System Engine – 9.9 mtons CO_2e
- SF_6 Electrical Breakers – 10.3 mtons CO_2e

Adding the estimated emissions from these other sources results in a facility-wide maximum of 1,932,464.2 metric tons CO_2E per year, which the facility will demonstrate compliance with on a rolling 12 month (calendar month) basis.

Part B.

Bay Area Air Quality Management District response to comments on BACT Analysis for Greenhouse Gas Emissions for the Russell City Energy Center Facility

Introduction

In the Draft Permit and Statement of Basis for the Russell City Energy Center, the Air District acknowledged its role as the primary air quality regulatory agency for the Bay Area and the importance of demonstrating leadership to address the problems of global climate change. The Statement of Basis said that global climate change is exacerbated by emissions of so-called greenhouse gases, including carbon dioxide (CO_2), nitrous oxide (N_2O) and methane (CH_4), and that the generation of electricity from natural gas resulted in emissions of each of these greenhouse gases, in addition to the criteria pollutants addressed elsewhere in the Statement of Basis and Draft Permit. The Statement of Basis said the Air District's efforts would be closely coordinated with California's initiatives to address global climate change at the state level, including through the efforts being led by the California Air Resources Board (Air Resources Board) pursuant to the California Global Warming Solutions Act of 2006, known as "Assembly Bill (AB) 32", Cal. Health and Saf. C. §§ 38500 et seq.).

Status of Greenhouse Gas Regulation in Federal PSD Program

The Statement of Basis observed that the status of greenhouse gas regulation is not as well developed at the federal level, particularly under the federal PSD permitting program. The Clean Air Act requires that a PSD permit must include BACT emissions limits for every pollutant subject to regulation under the Clean Air Act (42 U.S.C. §§ 7475(a)(4), 7479(3)). EPA's rules for the PSD program require PSD permits for "regulated NSR pollutants," which are defined as (among other things), pollutants that are subject to regulation under the Act." 40 C.F.R. §§ 52.21(j)(2), (b)(50). The Statement of Basis reported on the uncertainty regarding whether or not greenhouse gases are "subject to regulation" under the Clean Air Act, as illustrated by recent cases in front of the U.S. EPA's Environmental Appeals Board.

In re Deseret Power Electric Cooperative

As reported by the Statement of Basis, on November 13, 2008, U.S. EPA's Environmental Appeals Board (EAB) issued a decision in a petition regarding a PSD permit for a coal-fired power plant. In that case, In re Deseret Power Electric Cooperative, PSD Appeal No. 07-03 (EAB 2008) (Deseret), the EAB found that the EPA had not previously made any determination that would constrain its discretion to decide whether or not greenhouse gases should be regulated under the PSD Program. Accordingly, the EAB remanded the issue to U.S. EPA Region 8, with directions that the Region should consider the issue of whether EPA should exercise its discretion to regulate greenhouse gases under the PSD program. The EAB also suggested that it may be more appropriate for EPA to address this issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. Id., Slip. Op. at p. 63-64.

The Johnson Memorandum

A number of developments have occurred since the Air District issued the Draft Permit and Statement of Basis in early December. On December 18, 2008, EPA's then-Administrator, Stephen Johnson, issued a policy memorandum in response to the EAB's opinion in In re Deseret Power Electric Cooperative. This memo found that EPA would not regulate CO_2 under the PSD program solely because it must be monitored under other provisions of the Clean Air Act. (Memorandum, Stephen L. Johnson, Administrator, EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program, December 18, 2008; notice provided at 73 Fed. Reg. 80300 (Dec. 31, 2008), hereinafter, "Johnson Memorandum".) This determination was based in part upon EPA's finding that, to date, no federal PSD permit issued by EPA or a state acting on its behalf has previously included a limit on CO_2. (Id., at 11.)

Grant of Sierra Club's Petition for Reconsideration of Johnson Memorandum

The Johnson Memorandum was challenged as unlawful and, on February 17, 2009, EPA Administrator Lisa Jackson formally granted Sierra Club's petition for reconsideration of the Johnson Memorandum.[1] As a consequence, EPA is now reconsidering whether PSD permits must include limits on CO_2. According to the Administrator's February 17 letter, EPA will allow for public comment on the issues raised by both the Johnson Memorandum and the EAB's opinion in In re Deseret Power Electric Cooperative. While Administrator Jackson declined to "stay" the effectiveness of the Johnson Memorandum during its reconsideration, she emphasized that, given EPA's decision to grant reconsideration of it, "PSD permitting authorities should not assume that the memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." Id. The following day, the EAB issued another decision in the case of In re Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02 (EAB, 2009), remanding this same issue back to the delegated state agency to decide, consistent with its opinion in In re Deseret Power Electric Cooperative.

The EAB's opinion in In re Deseret Power Electric Cooperative suggested that the issue of whether PSD permits must include emissions limits for CO_2 and other greenhouse gases might better be decided in a rulemaking that was nationwide in scope (rather than in a particular permit decision). Cognizant that the Johnson Memorandum is not the "last word" on this issue, the Air District, as delegate agency for purposes of issuance of this PSD permit, need not decide the legal issue because the Applicant has asked

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[1] Letter, Lisa P. Jackson to David Bookbinder, February 17, 2009, available at: http://www.epa.gov/air/nsr/documents/20090217LPJlettertosierraclub.pdf.

the Air District to perform a BACT analysis for the project's emissions of CO_2 and other greenhouse gases and impose enforceable permit conditions limiting the emissions of these pollutants.

Summary of Statement of Basis and Draft Permit's Analysis of BACT for Greenhouse Gas Emissions

In the Draft Permit and Statement of Basis, the Air District set forth its preliminary analysis, following EPA's "top-down" method for determination of BACT. However, because no such analysis has previously been conducted for CO_2 and other greenhouse gases, the Air District had to make-do without many of the resources it typically uses to identify BACT for criteria pollutants, such as the federal and California BACT clearinghouses.

Combustion Controls: High Efficiency Energy Generation

In "step one" of the top-down analysis, the Air District determined that, unlike other regulated air pollutants, which are often emitted as by-products of imperfect combustion and can be reduced by controlling the combustion process, there is no corresponding way to reduce the amount of CO_2 generated during combustion, as CO_2 is an essential product of the chemical reaction between the fuel and oxygen in which it burns. As such, the only way to reduce the amount of CO_2 generated by a fuel-burning power plant, according to the Air District's analysis, is to generate as much electric power as possible from the combustion through use of the most efficient generating technologies available. Combined-cycle natural gas turbine technology, such as proposed for Russell City Energy Center, is among the most efficient electrical generating technologies developed to-date, according to the Air District. The Statement of Basis noted that natural gas produces about half as much CO_2 as coal and substantially less emissions of both criteria and toxic air pollutants as well.

Post-Combustion Controls: Carbon Capture and Storage

The Air District identified carbon capture and storage (i.e., geologic sequestration of carbon) as the only potential "post-combustion" control technology for CO_2 emissions. Like "add-on technology" such as use of selective catalytic reduction (SCR) to further reduce the emissions of NO_x from low-NO_x combustion equipment, carbon capture and storage would further reduce CO_2 emissions beyond the levels achievable through use of the most energy efficiency power generation technology available. While energy efficiency generating technology is a feasible and proven technology, according to the Air District's analysis, carbon capture and storage is not currently feasible for projects such as Russell City Energy Center. Rather, the Air District found that this technology is still in its infancy and has not been deployed for any full-scale power plant in the United States, according to the Air District. Further, even if the technology had matured to commercial availability, its feasibility for any given project would depend upon the availability of an appropriate sequestration site in the vicinity. The Air District noted that investigations of the suitability of locations in Alameda County for geologic sequestration were ongoing, but no such sites had been demonstrated as appropriate. The Air District also found that carbon capture and storage may have ancillary environmental and societal impacts that warranted further evaluation before this technology could be considered feasible. For these reasons, the Air District eliminated carbon capture and storage from consideration as an available technology, but noted that it would continue to monitor its development for future applications.

In summary, the Air District identified high-efficiency power generation technology as the only available and feasible control technology to reduce greenhouse gas emissions from the project. As the top-ranked technology with no collateral adverse impacts, the Air District selected high-efficiency power generation technology as BACT and then proceeded to adopt a numerical limitation to reflect this. The Air District noted that the California Energy Commission has found that natural gas-fired combined cycle combustion turbine technology can achieve an efficiency of around 56% and that the efficiency level for the proposed project was 55.8%, which was squarely within the range of best-performing combined-cycle turbines, according to the Air District's analysis.

Development of Enforceable Permit Conditions

To establish an appropriate CO_2 limit, the Air District then reviewed emissions performance data from other similar facilities, including information from the Energy Commission that suggested the emissions from baseload combined-cycle gas turbine power plants ranged from 794 lbs to 1058 lbs per MW-hr of electricity generated. It also reviewed data from two similar Calpine power plants, the Delta Energy Center and the Metcalf Energy Center, which reported emissions for all six standard greenhouse gases of 855 and 812 lbs/MWhr (expressed as carbon dioxide equivalents or "CO_2E"), respectively, when calculated in accordance with the methodology provided for purposes of demonstrating compliance with the Emissions Performance Standard required by the Electricity Greenhouse Gas Emission Standards Act (Senate Bill 1368).

The Air District found these data informative, but said they only represented a "snapshot" of performance, rather than a continued demonstration of compliance for the life of the plant. Because no enforceable greenhouse gas emissions limits have previously been imposed in federal air permits, the Air District said it would exercise caution in determining an appropriate enforceable limitation. Given the need to ensure that the facility could meet these limits under all foreseeable operating conditions, the Air District applied a reasonable compliance margin and ultimately concluded that 1,100 lb/MW-hr would best represent BACT, if it were required for greenhouse gases. The Air District noted that such a limit was consistent with the most stringent regulatory limitation (i.e., the California Energy Commission's Emissions Performance Standard) and also compared favorably with the average emissions rate for all natural gas-fired power plants, according to EPA estimates.

In developing enforceable permit conditions, the Air District found that the facility would have to limit its CO_2 emissions to 684,200 lbs/hr to ensure compliance with the 1,100 lb/MW-hr standard, given the facility's maximum output of 622 MW. Because CO_2 emissions are proportional to the amount of fuel burned, the Air District proposed to ensure compliance with this BACT standard through an enforceable fuel throughput limit, expressed in terms of the heat input of the fuel burned (Higher Heating Value (HHV)). Using an emissions factor of 116.19 lbs CO_2 per million British thermal units (MMBtu) of heat input, the Air District found that 684,200 lbs/hr corresponded to 5,888.b MMBtu of heat input per hour for both turbine/HRSG trains combined, or 2,944.3 MMBtu/hr per turbine/HRSG train. It found that, by enforcing a heat input limitation of 2,238.6 MMBtu per hour per turbine/HRSG train, the Draft Permit would ensure that CO_2 emissions did not exceed the BACT limit. The Statement of Basis concluding that, to the extent EPA may exercise its discretion to require BACT for greenhouse gases, the Draft Permit's limitation on hourly, daily and annual heat input would ensure that the proposed Russell City Energy Center satisfied BACT.

Summary of Comments on Statement of Basis and Draft Permit's CO_2 BACT Analysis

The Air District received several comments on its BACT analysis for CO_2 and other greenhouse gases. A number of comments said that, by selecting 1,100 lb/MW-hr as BACT, the Air District had not set BACT at a level that reflected the maximum degree of reduction achievable. A number of commenters said that this level – the equivalent of the Energy Commission's Emissions Performance Standard – reflected a compromise between what could be achieved by the newest and most efficient technology and the levels achieved by older combined cycle natural gas-fired power plants. Thus, by setting the limit at 1,100 lb/MW-hr, the Air District had set BACT by reference to what can be achieved by existing technology, rather than innovative, more efficient generating technologies.

Several commenters said that, in addition to fossil-fueled combustion sources, the Air District also should have considered renewable sources of electric generation, such as wind and solar power. One commenter cited EAB decisions as supporting the proposition that BACT required consideration of more efficient generating technologies, including innovative fuel combustion techniques and production processes, for both greenhouse gases and criteria pollutants. Many commenters expressed their belief that the generating capacity from this project should be met instead through investment in renewable generating technologies. Several comments said that the technology for the project was selected years ago and did not reflect the most efficient technology available. Other comments alleged that the Air District's analysis failed to constitute a "true" BACT analysis, but instead was designed so that the technology already purchased by the Applicant could be used, even though it represented "old" or out-of-date technology.

One commenter noted that the Siemens' F-class turbines purchased by the Applicant are less efficient than Siemens' new G-class turbines, which could be used to achieve net plant efficiencies of 58% and are already in operation at a number of plants. This commenter also noted that Calpine was scheduled to complete construction of a plant which was licensed with an efficiency factor of 56.5%, without duct firing (lower heating level), as opposed to the 55% efficiency rating of the proposed Russell City Energy Center. According to this commenter, the Air District should examine the various components of the proposed combined-cycle technology to determine whether each individual component and their combination together reflected the most efficient means of generating power. The same commenter also noted that, although no information existed concerning the proposed facility's efficiency when using duct burners for peak generating capacity, the incremental heat rate of peaking capacity is generally estimated at levels of about 8,890 to 9,000 Btu/kWh, which corresponded to only about a 40% efficiency rate. According to this commenter, such a heat rate was higher than could be achieved by simple cycle gas turbines, which suggested that the Air District's BACT analysis should have considered simple cycle gas turbine technology as an alternative to duct burners for peaking power generation.

One commenter found that the Air District's expression of the BACT standard as an "input-based" limit which focused solely on the amount of fuel used was inadequate because it would not account for degradation in efficiency due to aging of the equipment or deferral of maintenance. This commenter stressed that an "output-based" metric was needed to assure the plant's efficiency would be retained over time. Similarly, another commenter said that merely limiting heat input did not assure BACT would be met during all periods of operation, e.g., startup or shutdown, or that the turbines were maintained to achieve their most efficient operation. According to this commenter, relying upon the operator's economic incentives to maximize efficiency (and thereby reduce its fuel costs) ignored economic realities in which companies made decisions to replace or maintain aging equipment.

A number of commenters suggested that 1,100 lb/MW-hr represented an unreasonably large compliance margin, with one commenter noting that this was 39% greater than what has already been achieved by combined-cycle technology. According to a number of comments, any compliance margin needed to be justified based upon unreliability in the test methods or actual performance data. One commenter said that, where there is uncertainty as to what can be achieved, the appropriate solution is to provide an "optimization period". According to this commenter, the Air District should require that the Applicant submit the "design basis" to the Air District. The Air District should then establish protocols to identify the appropriate test methods, criteria and averaging period to measure CO_2 and MWh net, the frequency of testing, and length of the optimization period. Some commenters said that, because CO_2 can be monitored continuously using standard measurements and technology, the Draft Permit should require continuous monitoring of both CO_2 and plant output, to assure compliance with an emissions limit stated in pounds per MW-hr.

A number of commenters said that the Air District had failed to perform a BACT analysis for emissions of other greenhouse gases, including methane (CH_4), nitrous oxide (N_2O) and sulfahexafluoride (SF_6) and for emissions from other emissions sources, such as the emergency backup diesel fire-pump engine.

Response to Comments on the BACT Analysis for CO_2 and Other Greenhouse Gases

Based on the comments it received on the proposed BACT analysis appearing in the Draft Permit and Statement of Basis, the Air District has refined its analysis of an appropriate BACT limitation for Russell City Energy Center's greenhouse gas emissions. The Applicant has provided additional information to support the Air District's determination that the proposed Russell City Energy Center constitutes the most efficient generation technology. As described previously (in Section II of this Response), the Air District disagrees with commenters who asserted that its BACT analysis failed to require the use of current technology, but instead reflected levels of control achieved at the time when the Applicant purchased the turbines in 2002. The original equipment manufacturer, Siemens, will be conducting upgrades to the equipment described in more detail in Section II, so that they are, in effect, the equivalent of Siemens 501 "FD3" combustion turbines available today. These upgrades are expected to result in an increase of 1.09% in the overall plant efficiency, from 55.3% (lower heating value (LHV)), to 56.4% (LHV). As provided further below, the Air District has found that this represents the most efficiency generating technology available and, for that reason, would constitute the "best available control technology" for emissions of carbon dioxide and other greenhouse gases.

Consideration of Renewable Generation Sources as Alternatives to Proposed Project

Regarding consideration of renewable generating sources, such as wind and solar, as an alternative to the project, the Air District would note that both the California Energy Commission and the investor-owned utility to which the proposed project's generating capacity will be committed, Pacific Gas and Electric (PG&E), have aggressive goals and targets for increasing renewable generating capacity within the Bay Area. In separate proceedings, both the Energy Commission and PG&E have concluded that there are no renewable energy projects that would meet the need for new load generating capacity in the Bay Area in the near term.

The Air District would note that, in conducting BACT analyses for power plants, permitting authorities have not typically considered whether renewable alternatives would achieve lower emissions and should therefore be required as BACT. The Air District acknowledges that "this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire." EPA NSR Manual, at B.13 (1990). In this respect, as part of the power plant licensing process, the California Energy Commission makes findings regarding the need for, and alternatives to, the proposed project, which includes consideration of renewable generating sources. Because another state agency has the authority and expertise to make decisions on the availability of renewable resources as alternatives to proposed fossil fuel generating sources, the Air District will refrain, as part of the PSD permitting process for this facility, from duplication of the Energy Commission's consideration of the need for and availability of renewable alternatives to the proposed source.[2]

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[2] For a discussion of the obligations and discretion of permitting authorities to engage in a broader analysis of the "need" for a proposed electric generating facility and alternatives to its construction, such as energy efficiency, solar or wind resources or demand management, *see In re Prairie State Generating Company*, PSD No. 05-05, 14 E.A.D. __, slip op. at 40-44, which provides as follows:

> Moreover, we have previously recognized that it is appropriate for a permit issuer to refrain from analyzing whether a proposed facility is needed where the state has specifically tasked another state agency with authority to consider that issue. *See In re SEI Birchwood, Inc*., 5 E.A.D. 25 (EAB 1994) (delegated state acting as permitting authority); 33 *see also In re EcoEléctrica, LP*, 7 E.A.D. 56, 74 (EAB 1997) (holding that it was not clear error for the permit issuing Region to defer to the state agency tasked with the responsibility to consider need for the facility); accord *In re Kentucky Utils. Co*., PSD Appeal No. 82-5, at 2 (Adm'r 1982) (same). We conclude that it is

For this project, the Energy Commission concluded that, because of the lower efficiencies and intermittent availability of alternative generation technologies, “they do not fulfill a basic objective of the plant: to provide power from a baseload facility to meet the growing demand of reliable power in the San Francisco Bay Area.”[3] According to the 2002 Energy Commission Decision, “the [Energy Commission] Staff witness testified that she does not believe geothermal, hydroelectric, solar, wind and biomass technologies present feasible alternatives to the proposed project.” Id.

As suggested by the 2002 Energy Commission Decision, because wind and solar generating sources are intermittent, their availability as a resource must be supported by baseload generating resources, such as the proposed facility, which ensure an adequate supply of power in periods when solar and wind sources do not provide power to the grid.

For comparison, to replace the proposed project’s generating capacity, it would take between two and four hundred new wind turbines, each one over twice as high as the proposed project’s tallest stack. According to the 2002 Energy Commission Decision, “[w]ind generation ‘farms’ generally require 17 acres per megawatt, with 600 megawatts requiring 10,200 acres, approximately 690 times the amount of space taken by the proposed plant site and linear facilities.”[4] Assuming other environmental impacts, such as bird collision hazards and other species concerns, were adequately addressed, a wind farm to replace the capacity of the proposed plant would occupy a vastly greater area of land. Construction of such extensive wind generating resources would also involve other environmental and transmission capability considerations, as demonstrated by recent efforts to construct transmission corridors in Southern California or off-shore wind farms in Massachusetts. Even assuming that such a large amount of land could be obtained by the Applicant at or within the vicinity of the Project site, use of so much land for a wind farm would likely involve significant environmental impacts that would preclude its construction in the Bay Area. Because the Project objectives include providing power to the Bay Area, replacement of the Project with the a wind farm would not be technically feasible for the Project site and therefore would likely be eliminated at Step 2 of a “top-down” BACT analysis.

Solar resources involve similar considerations of feasibility, space constraints and environmental considerations. According to the 2002 Energy Commission Decision, “central receiver solar thermal projects require approximately 5 acres per megawatt; therefore 600 megawatts would require approximately 3,000 acres, or over 200 times the amount of land area taken by the proposed plant site and linear facilities.”[5] The Energy Commission also found that “[p]arabolic trough solar thermal technology requires similar acreage per megawatt.” Id. In contrast, residential and commercial rooftop photovoltaic systems would not pose the same environmental concerns and are featured as an important element in the California Air Resources Board’s overall Scoping Plan to achieve the greenhouse gas emission reduction goals of AB 32. While such resources will play an important role in California’s efforts to combat climate change, they are only intermittently available and will require baseload generation to provide power to the grid at other times. In light of this, replacement of the Project with similar capacity from a solar project is not technically feasible, given the Project’s goals, and therefore would be eliminated at Step 2 of the top-down BACT analysis.

> similarly appropriate for the PSD permitting authority to take into account a state legislature’s decision to deregulate the electric power generation industry and allow individual firms to make a market-based business decision regarding likely future demand for electricity.

[3] California Energy Commission, *Commission Decision, Russell City Energy Center* (July 2002, P800-02-007) (hereinafter, “2002 Energy Commission Decision”), 19; available at: http://www.energy.ca.gov/sitingcases/russellcity/index.html.

[4] 2002 Energy Commission Decision, at 18.

[5] *Id*.

Consideration of Other Fuel Sources

As suggested previously, the emissions of carbon dioxide (CO_2) during fossil fueled combustion are strongly correlated to the amount of carbon in the fuel stream. In light of this and given that "best available control technology" includes, among other things, "fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each … pollutant"[6], the Air District's BACT analysis has also considered whether electric generating facilities which use other fuels, besides natural gas, could achieve lower emissions of CO_2 and other greenhouse gases. In general, the Air District has found that the emissions from natural gas-fired combustion technology is substantially lower than from plants using other fuel sources.

For example, the average emissions rate from coal-fired generation in the United States have been estimated by U.S. EPA at 2,249 lbs/MWh of CO_2.[7] Other sources estimate even higher average emission rates for coal-fired generation. During the joint rulemaking proceedings held in 2007 regarding greenhouse gas emission standards, the California Energy Commission and Public Utilities Commission calculated the average emission rates of coal-fired power plants located in the Pacific Northwest and Pacific Southwest at 2,307 lbs/MWh and 2,355 lbs/MWh CO_2, respectively.[8] However, just as the 1,100 lbs/MWh Emissions Performance Standard resulting from those proceedings reflected the emissions of CO_2 achievable from existing natural gas-fired combined-cycle power plants, these estimates for coal-fired generation reflected the emissions from existing coal generating technology, including older plants.

In comparison to existing coal-fired plants, advanced coal generation technologies would achieve substantially lower emissions of CO_2. According to a recent report prepared by Pace Global Energy Services, the U.S. Department of Energy's National Energy Technical Laboratory has estimated the emissions, in CO_2-equivalents (CO_2E), for a 550-MW advanced ultra-supercritical coal-fired power plant at 1,773 lbs/MWh CO_2E and for a 633-MW integrated gasification combined cycle (IGCC) coal-fired plant at 1,714 lbs/MWh CO_2E.[9] Although both of the estimated coal plants are similar in size to the proposed Russell City Energy Center and therefore might provide an alternative to the proposed source, they both would emit greenhouse gases at twice the rate of the proposed Russell City Energy Center. Thus, without available carbon capture and sequestration technology, it does not appear that advanced coal generating scenarios could be found to constitute BACT for an electric generating facility of similar purpose and size. Rather, combined-cycle natural gas-fired combustion technology would clearly be identified as the superior control for greenhouse gases at Step 3 of the top-down BACT analysis.

Another fuel choice might include combustion of biomass, such as wood ships or agricultural waste. However, the 2002 Energy Commission Decision found that no biomass fuel source existed in large enough quantities in the vicinity, so that biomass represented a feasible alternative to the proposed Russell City Energy Center.[10] The Energy Commission also found that "biomass plants are typically sized to generate less than 10 MW, which is substantially less than the capacity of the 600 MW RCEC project."

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[6] 42 U.S.C. § 7479(3); 40 C.F.R. § 51.166(b)(12) (definition of "best available control technology).

[7] Environmental Protection Agency, *Coal*, http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html .

[8] California Air Resources Board, *Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01*, June 20, 2007; http://www.arb.ca.gov/cc/ccei/presentations/OOS_EmissionFactors.pdf.

[9] Pace, prepared for Center for Liquefied Natural Gas, *Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results*, February 3, 2009, at 11-12; available at: http://www.lngfacts.org/resources/LCA_Assumptions_LNG_and_Coal_Feb092.pdf .

[10] 2002 Energy Commission Decision, supra at note 40, at 18.

Id., at 18-19. For this reason, combustion of biomass does not appear at this time to provide a feasible alternative to the proposed project's purpose.

Consideration of Other Natural Gas-Fired Combustion Turbines for Baseload Combined-Cycle Generation

One commenter noted that the Siemens' F-class turbines purchased by the Applicant are less efficient than Siemens' new G-class turbines, which reportedly achieve net plant efficiencies of 58% and are already in operation at a number of plants. This commenter also noted that Calpine was scheduled to complete construction of a plant licensed with an efficiency factor of 56.5%, without duct firing (lower heating level), as opposed to the 55% efficiency rating of the proposed Russell City Energy Center. According to this commenter, the Air District should examine the various components of the proposed combined-cycle technology to determine whether each individual component and their combination together reflected the most efficient means of generating power.

The Air District has evaluated the availability/technical feasibility of using G-class turbines for the proposed project and whether it would achieve additional reductions that would constitute BACT. The Applicant has proposed a 612-MW combined cycle power plant. Although one commenter suggested that the Air District should examine each component of a combined cycle plant individually to assure that each component reflects the most efficient choice available, such an approach will not necessarily generate the most efficient plant. Through use of the Siemens' 501 FD3 combined cycle gas turbines for this project, the Applicant expects to achieve a gross plant efficiency rate (lower heating value (LHV)) of 56.45% without duct burning and 56.44% with duct burning. However, if the Air District were to require use of the Siemens' 501 G-class combustion turbines, which have substantially greater output than F-class turbines, the Applicant would need to use a substantially smaller steam turbine (143 MW) to provide the equivalent plant output, which is limited at 612.8 MW (net).[11] This would result in an inefficient bottoming cycle and would lower the overall plant gross efficiency rating from 58% (LHV), as suggested by one commenter, to 49.8% (LHV), according to an analysis provided by the Applicant. Id.

As a consequence, any marginally increased efficiency associated with G-class turbines would be eliminated upon their incorporation into a combined cycle plant of the proposed size. Because of the ancillary impacts that would result from such an efficiency loss, in terms of increased fuel consumption and emissions (on a pounds per MW-hr basis) of both criteria pollutants and greenhouse gases, use of G-class turbines would be eliminated from consideration as BACT.

Further, as illustrated by this example, identifying BACT by selection of the most efficient available piece of equipment for each component of a combined cycle power plant – without evaluating them within the specific configuration of the proposed plant – may result in a less efficient plant. In addition, the Air District would note that BACT analysis has not traditionally been used to make fundamental changes in the source, such as the size of the proposed facility, which represents a common "two by one" combined cycle arrangement that Calpine has used at a number of other facilities.

As suggested previously, with the "FD3" upgrades that the Applicant intends to perform before operation of the existing gas turbines, it anticipates achieving a gross plant efficiency of 56.45% (LHV) without duct burning and 56.44% with duct burning.[12] This compares very favorably to the information the Air

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[11] Table, "RCEC, Output limit 612800 kW", prepared by A. Prusi, P.E. (Calpine Corporation) submitted to Air District by email dated April 2, 2009, from K. Poloncarz.

[12] Table, "Comparison of Plant fired vs unfired.pdf", prepared by A. Prusi, P.E., submitted to Air District by email dated April 2, 2009 from K. Poloncarz.

District has reviewed regarding the efficiency of other similar sized combined-cycle power plants recently proposed or constructed in California. For example, the Colusa Generating Station, a 530 MW facility which is currently in construction, has a rated efficiency of 56% (LHV), according to information obtained from proceedings in front of the California Energy Commission (Energy Commission).[13]

As another example, Pacific Gas and Electric's (PG&E) 530 MW Gateway Generating Station Unit 8, which just completed construction in January 2009, has a plant efficiency rate of 54.1% (LHV).[14] In addition, the 550-MW Palomar Energy Center discussed at length in Section II of this Response to Comments, which completed construction in 2006, has a rated efficiency of 50% (LHV), without duct firing and 49% (LHV) with duct firing.[15] Further, according to the February 2009 Energy Commission Preliminary Staff Assessment, Avenal Energy, "if constructed and operated as proposed, would generate 600 MW (nominal gross output) of electric power at an overall project fuel efficiency of 50.5 percent LHV."[16] In this respect, we would note that one commenter suggested that Avenal Energy would, based upon the its February 2008 application for certification submitted to the Energy Commission, supposedly achieve emissions of CO_2 as low as 499.7 lb/hr; however, based upon our review of the Energy Commission Staff's recent Preliminary Staff Assessment and its conclusions regarding the plant's overall efficiency rating, we find that figure doubtful.

The following table illustrates the power plant efficiency for similar sized combined-cycle power plants that have recently applied to the Energy Commission for a license or are currently undergoing construction or in operation.

Name of Facility	Application w/ CEC	MW	Efficiency (LHV)
Inland Empire Energy Center	8/17/2001	790	59.6%
Russell City Energy Center	5/22/2001	578 612	56.45% (w/o duct firing) 56.44% (w/ duct firing)
Colusa Generation Station	11/6/2006	660	56%
Contra Costa (PG&E Gateway) Unit 8 Power Project	1/21/2000	530	54.1%
Blythe Energy Project Phase II	2/19/2002	520	55-58% (est.)
Lodi Energy Center	9/10/2008	255	55.6%
El Segundo Power Redevelopment Project	6/19/2007	560	55.4%
Carlsbad Energy Center Power Plant	9/14/2007	558	55-56% (est.)
CPV Vaca Station Power Plant	11/18/2008	660	55%
Victorville 2 Hybrid Power Project	2/28/2007	563	52.7% (w/ duct burn) 59.0% (thermal solar)
Kings River Conservation District Community Power Project	9/27/2007	565	50.5% (Siemens) 49.2% (GE)

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[13] California Energy Commission, *Final Staff Assessment, Colusa Generating Station*, November 30, 2007, Exhibit 200; sponsored by Staff, and received into evidence on January 23, 2008, at 5.3-4; available at: http://www.energy.ca.gov/2007publications/CEC-700-2007-003/CEC-700-2007-003-FSA.PDF.

[14] California Energy Commission, *Commission Decision, Contra Costa Unit 8 Power Project*, May 2001 (00-AFC-1), at 159; available at: http://www.energy.ca.gov/sitingcases/contracosta/documents/2001-05-30_CONTRACOSTA.PDF.

[15] California Energy Commission, *Final Commission Decision, Palomar Energy Project*, August 2003, AFC-01-24, at 77; available at: http://www.energy.ca.gov/sitingcases/palomar/documents/2003-08-08_FINAL_DECISION.PDF.

[16] California Energy Commission, *Preliminary Staff Assessment, Avenal Energy*, February 2, 2009, 08-AFC-01, at § 5.4-6; available at: http://www.energy.ca.gov/2009publications/CEC-700-2009-001/CEC-700-2009-001-PSA.PDF.

Name of Facility	Application w/ CEC	MW	Efficiency (LHV)
Avenal Energy Power Plant	2/21/2008	600	50.5%
Palomar Energy Project	8/2003	550	50% (w/o duct firing) 49% (w/ duct firing)
Willow Pass Generating Station	6/30/2008	550	48% (approx.; FP-10)

Based upon the foregoing overall plant efficiency ratings for similar sized, combined-cycle plants recently constructed or proposed in California, the Air District finds that the proposed Russell City Energy Center's plant efficiency of 56.4% (LHV) would be deemed the "best available control technology" (BACT) for greenhouse gas emissions. Of all similar facilities in existence, under construction or proposed for construction in California, the only facility with a higher efficiency rating is Inland Empire Energy Center, which, like Russell City Energy Center, is another joint Calpine and GE venture.

Inland Empire Energy Center was originally licensed with an efficiency rating at 56.5% (LHV), without duct burning and 53.2% (LHV) with duct burning. The original license issued by the Energy Commission authorized use of GE PG-7251(FB) combustion turbine-generators. However, in 2005, Calpine and GE agreed to proceed instead with installation of the first 60-hertz (Hz) Frame 7H™ combined cycle generating system produced by GE, which has a combined cycle rating of 59.6%.[17] The Frame 7H™ System will not likely become available for other commercial applications until GE and Calpine complete demonstration of it at Inland Empire Energy Center. The first Frame 7H™ unit was installed at Inland Empire Energy Center and began operation on January 28, 2009.[18] Upon installation of the second unit, the project will generate 790 MW (net). While promising, the 60Hz Frame 7H™ is not available at this time; GE and Calpine reportedly agreed to its use at Inland Empire Energy Center, so that GE could continue pursuing the development and testing of the product, with the goal of making it available for wider use in the 60Hz market.[19]

Based upon the Air District's assessment of commercially available systems which either are in-use or proposed for combined-cycle operation in California, the Air District has determined that the proposed Russell City Energy Center's efficiency of 56.4% (LHV) represents BACT for the project.

Consideration of Simple-Cycle Combustion as Alternative to Duct Burning for Peak Generating Capacity

One commenter suggested that the Air District should have considered simple cycle gas turbine technology as an alternative to duct burners for peaking power generation. The commenter said the proposed facility's efficiency would be reduced when using duct burners for peak generating capacity,

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[17] California Energy Commission, Memorandum, *Inland Empire Energy Center Power Project (01-AFC-17C) Staff Analysis Of Proposed Modifications To Change To GE 107H Combined-Cycle Systems, Increase Generation and Add Additional Laydown Areas*, Connie Bruins, Compliance Division Manager (Jun. 8, 2005) (Inland Empire Energy Center Staff Analysis Memorandum), 60; available at: http://www.energy.ca.gov/sitingcases/inlandempire/compliance/2005-06-10_FINAL_ANALYSIS.PDF.

See also California Energy Commission's Staff Errata and Response to Project Owner's Comments, Attachment 1, "Staff's responses to Calpine's Minor Changes (Calpine Attachment 2)" (June 21, 2005), at 2 (noting that the efficiency rating should read 59.6% (LHV), rather than the higher figure previously proposed); available at: http://www.energy.ca.gov/sitingcases/inlandempire/compliance/2005-06-20_IEEC_AMENDMENT.PDF.

[18] *See* http://www.energy.ca.gov/sitingcases/all_projects.html.

[19] *Inland Empire Energy Center Staff Analysis Memorandum*, supra at note 47, at iii ("GE proposes to install, operate and test this initial Frame 7H machine. In order to pursue this essential step in the development and marketing of this new product, GE has completed an agreement with Calpine to install the first Frame 7H machine, along with a second machine, at the [Inland Empire Energy Center]").

assuming an incremental heat rate of peaking capacity of about 8,890 to 9,000 Btu/kWh. According to this commenter, such a heat rate was higher than could be achieved by simple cycle gas turbines, which suggested that the Air District's BACT analysis should have considered simple-cycle technology as an alternative to the peaking capacity for this facility.

The rated base capacity for the proposed facility is 578.7 MW, with an additional 34.1 MW of peak capacity due to duct burning. The Air District's modeling analysis assumed 4,000 operating hours for each gas turbine's duct burner. However, the Applicant expects actual operation of the duct burners to be substantially less, given that, as pointed out by the commenter, the heat rate for duct burning is substantially higher than for baseload generation and therefore will only be called to dispatch after available peaking capacity with a lower heat rate has already been dispatched.

While the BACT analysis requires a sufficiently "hard look" at the applicant's proposed design and whether there are lower-emitting alternatives, permitting agencies need not use the BACT analysis to require the applicant to change its design from construction of a combined cycle to simple cycle facility or to eliminate and replace key elements of its design with wholly separate sources.[20] Accordingly, for purposes of the BACT analysis of greenhouse gases, the Air District would generally consider whether both the baseload and peak capacity for a combined-cycle plant with duct burning represented the most efficient means of generation; it would not consider requiring the elimination of peak capacity.

The Air District has evaluated the cost to replace the proposed facility's duct burners with simple-cycle generating technology that could generate approximately the same amount of energy during peak demand periods. One option would be to use a smaller gas-fired turbines, such as the LM6000 gas turbine generator set manufactured by GE. A basic LM6000 is rated at 42.3 MW, with a heat rate of 8,308 Btu/kWh (LHV); with additional features, a LM6000 Sprint ("Spray-Intercooled Turbine") is rated at 46.9 MW and has a heat rate of 8,235 Btu/kWh (LHV).[21] In comparison, the heat rate for the proposed Russell City Energy Center's peak capacity (rated at 46.3 MW) is 7,595 Btu/kWhr (LHV).[22] As a consequence the use of proposed Russell City Energy Center's duct firing for peak capacity will be a more efficient means of generation of peak capacity than installation of the most efficient form of simple cycle generation capacity available. As indicated above, the effect of duct firing on plant efficiency is very minimal, with an impact on the efficiency rate of 0.01%: Without duct firing, the gross plant efficiency is 56.55% (LHV); with duct firing, the gross plant efficiency is 56.54% (LHV). According to the Applicant, the marginal difference in plant efficiency is because the heat recovery steam generators (HRSGs) are approximately 85% effective in heat transfer from the burners and the steam flow, pressure and temperature are significantly increased, which greatly increases steam turbine output.[23]

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[20] *See, e.g., In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, at 51-52 (2003) (finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility", at 51-52; *see also In re Prairie State Generating Company*, PSD Appeal No. 05-05, 14 E.A.D. __, slip op. at 32 (2006) (referencing the EAB's recognition in *In re Kendall New Century Development* that "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility").

[21] GE Aero Energy Products, brochure, *LM6000 SPRINT ™ Gas Turbine Generator* Set, available at: http://www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf

[22] *Calpine Energy Center, Russell City Energy Center, Heat Balance Diagram*, December 18, 2008; submitted to the Air District as trade secret/confidential business information on March 29, 2008 (hereinafter, "Heat Balance").

[23] Table prepared by A. Prusi, P.E. (Calpine Corporation), submitted by email from K. Poloncarz, April 2, 2009.

Even if it were not for the superior performance of Russell City Energy Center's duct burners in comparison to an LM6000, replacement of duct burners with a separate simple-cycle unit would likely be eliminated from consideration as BACT based upon the significantly greater cost and ancillary environmental impacts. According to a report prepared by the California Energy Commission, the cost to replace the proposed Russell City Energy Center's peaking capacity with a simple cycle plant would be approximately $508.02 per MWh for an investor-owned utility (IOU) plant or $647.28 per MWh for a "merchant" plant.[24] In contrast, the total estimated cost for a 550-MW combined cycle plant with duct firing is approximately $95.59 or $103.52 per MWh for an IOU or merchant plant, respectively. Id. (The cost for a combined cycle facility without duct firing is estimated for an IOU and merchant plant at $94.47 or $102.19 per MWh, respectively. Id.) In light of these estimates, the marginal cost associated with duct firing at a facility like the proposed Russell City Energy Center would appear substantially more favorable than the cost to replace its peak capacity with a separate simple-cycle unit.

Consideration of Solar Thermal Technology as Alternative to Duct Burning for Peak Generating Capacity

Another alternative to using duct burners for peak capacity generation would be to use solar thermal technology, as proposed in an application to the California Energy Commission for the Victorville 2 Hybrid Power Project.[25] The Victorville Project will be a 570-MW facility located in the Mojave Desert and consist of natural gas-fired, combined-cycle generating equipment, integrated with solar thermal generating equipment. The solar thermal input is intended to provide approximately 10% of the power generated by the facility during peak periods. Use of solar thermal equipment is projected to increase the overall thermal efficiency of the combined-cycle plant from 52.7% to 59% (LHV) because it would allow the facility to reduce firing of the duct burners during peak periods and replace that peak capacity with the input from the solar thermal generating equipment. Id.

The solar thermal component of the Victorville "hybrid" Project will consist of a series of diurnal, single-axis-tracking parabolic trough solar collectors laid out in parallel rows aligned on a north-south horizontal axis. Each solar collector will track the sun from east to west to assure that it continuously reflects the greatest amount of sunlight possible onto a "linear receiver", which contains a heat transfer fluid that circulates through the receiver and returns to a series of heat exchangers, where it is used to generate high-pressure steam for two heat recovery steam generators (HRSGs).

The projected increase in overall plant efficiency attributable to the solar thermal element would clearly render the Victorville Project the most efficient option available for generating power during peak demand periods. In comparison to the 59% efficiency rating (LHV) of the Victorville hybrid project during such periods, the proposed Russell City Energy Center's baseload efficiency of 56.45% (LHV) would only be reduced to 56.44% during periods of duct burning.

While the solar thermal element proposed for Victorville may constitute a potentially feasible technology for purposes of the BACT analysis of peak capacity generation, the Air District has nevertheless eliminated it from consideration for this project because, unlike the proposed site in the Mojave Desert for the Victorville project, the proposed location for Russell City Energy Center is relatively compact and would not provide adequate space for installation of solar collectors. Rather, the proposed project would

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[24] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Final Staff Report, December 2007, CEC-200-2007-011-SF, at 10, 12; available at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF. An LM6000 is the equivalent of "Small Simple Cycle" in the Energy Commission's report.

[25] California Energy Commission, *Application for Certification, Victorville 2 Hybrid Power Project*, February 8, 2007, at 2.1-14; available at http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/.

be located adjacent to the City of Hayward's waste water treatment plant, so it can recycle approximately 4 million gallons per day of effluent from the City's treatment plant for use in the power plant's operations, eliminating the discharge of that waste water to the San Francisco Bay. Additionally, the proposed facility would reuse the former site of a machining operations, which is currently vacant and impacted by contamination resulting from its historic use. Given that the Project's objectives include both providing power to the San Francisco Bay Area and siting near a source of recycled waste water and the space constraints imposed on a developer on a former industrial site in an urban area, replacement of the Project's peak capacity with a solar thermal plant is not feasible for the source.

Assuming that the Applicant could purchase or lease the additional land required to construct a solar thermal plant to replace some of the peak capacity generated by the proposed facility's duct burners, using 250 acres of property for construction and operation of a solar thermal plant would result in potentially significant ancillary environmental impacts, including to sensitive or listed species. These ancillary impacts must be balanced against any potential increase in power plant efficiency that would be achieved.

In contrast, the Applicant has proposed Russell City Energy Center for a currently vacant, brownfield site, adjacent to a source of waste water, which the proposed facility will recycle and use in its operations, eliminating up to 4 million gallons of waste water from the City's discharge to the Bay. Moreover, the project has been proposed for construction in an industrialized area where limitations on available property would preclude construction of such a thermal solar plant. The Energy Commission determined that the objectives of the proposed Russell City Energy Center were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices", and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[26] These objectives could not be achieved if the Air District required the facility to be located in a place where sufficient land was available to allow for construction of a solar thermal plant. For these reasons, the Air District has found that thermal solar peaking capacity is not a feasible alternative for the Project's proposal to use duct burning to generate peak capacity.

Expression of BACT Standard as Enforceable Limit

Regarding the Air District's preliminary determination that BACT constituted 1,100 lb/MW-hr CO_2-equivalent (CO_2E), the Air District agrees with commenters that this did not constitute the lowest level achievable by new technology and therefore does not represent BACT. Rather, the Air District proposed the higher level as BACT because facilities had not previously been required to comply with an efficiency-based metric for greenhouse gas emissions and there was substantial uncertainty regarding whether the lowest levels achievable could be met consistently over the life of the plant. According to some commenters, the Air District disregarded the figures it cited on the levels that could be achieved by facilities using combined cycle generating technology, which indicated that some facilities could achieve lower levels of approximately 800 lb/MW-hr CO_2E. In response to these comments, the Air District has reconsidered its BACT determination and established BACT as an enforceable limitation that is substantially below the level proposed in the Statement of Basis and consistent with the levels proposed by commenters.

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[26] 2002 Energy Commission Decision, at 17.

Use of an Output-Based Compliance Standard

The Air District has also responded to comments which asserted that the proposed means for demonstrating compliance was inadequate because it was "input-based" rather than "output-based" and, as such, would fail to assure that the equipment was operating at expected efficiencies or being properly maintained over time. In light of these comments, the Air District has proposed a compliance demonstration that will account for anticipated degradation of the equipment, but also assure that it will not suffer undue degradation (e.g., through deferred maintenance or failure to replace components at the end of their intended life), such that it fails to achieve the anticipated efficiencies that provided the basis for the BACT determination. The following discussion sets forth the Air District's basis for establishing an enforceable limitation on the facility's "heat rate" that the facility must meet through an annual performance test.

Design Base Heat Rate

The Applicant's anticipated upgrades should result in a gross plant efficiency of approximately 56.4% (Lower Heating Value (LHV)). Electric generating facilities typically measure their efficiency in terms of the "heat rate", which is the energy content of the fuel, in British thermal units (Btu) that it takes to generate a kilowatt-hour (kW-hr) of electric power to the grid. The proposed facility is expected to have a "Design Base Heat Rate" of 6,852 Btu/kWhr (HHV), based on operation of both combustion turbines with no duct firing, corrected to ISO conditions.[27] Stated in pounds of CO_2-equivalent emissions (CO_2E) per megawatt hour (lbs/MWhr), this is between 792.9 and 815.5 lbs/MWhr, depending upon which CO_2 emissions factor is applied.[28] The Design Base Heat Rate with duct firing is 6,970 Btu/kWhr (HHV), which amounts to between 806.5 and 829.5 lbs/MWhr CO_2E (again, depending upon which emissions factor for CO_2 is applied). This represents what the plant is expected to achieve when it is new and clean; it does not represent what it will achieve over time as the equipment incurs degradation between major maintenance overhauls. It also does not represent the equipment manufacturer's guaranteed levels of performance.

The Design Base Heat Rate of 6,852 Btu/kWhr (HHV) without duct firing and 6,970 Btu/kWhr (HHV) with duct firing reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. This auxiliary load includes the proposed facility's recycling of waste water from the adjacent City of Hayward's waste water treatment

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[27] *Calpine Energy Center, Russell City Energy Center, Heat Balance Diagram*, supra note 57.

[28] The lower and higher figure reflect application of the emissions factors for CO_2 applicable under U.S. EPA's Climate Leaders program – 115.6 lb/MMBtu – and the Part 75 Acid Rain Monitoring Program, 118.9 lb/MMBtu. Other relevant emissions factors include the California Climate Action Registry's factor of 116.9 lb/MMBtu and the Air Resources Board's mandatory reporting rule, which applies emissions factors for CO_2 between 116.5 and 120.5 lb/MMBtu of natural gas, depending upon the Btu content of the gas stream.

The Air District would also note that it is following the convention of stating emissions of greenhouse gases in terms of "CO_2-equivalents" (CO_2E), which, for this source, include emissions of methane (CH_4) and nitrous oxide (N_2O) as well. These two pollutants have a higher "global warming potential" than CO_2, reflecting their relative propensity to trap sunlight that would otherwise be reflected back into outer space within the Earth's atmosphere and thereby contribute to global warming. The emissions factors and global warming potentials for N_2O and CH_4 are specified by the Air Resources Board's mandatory reporting rule: For N_2O, the emissions are 0.00022 lbs/MMBtu and the global warming potential is 310; for CH_4, the emissions are 0.0020 lbs/MMBtu and the global warming potential is 21.

plant. The proposed facility will process roughly 4 million gallons of water a day from the waste water treatment plant, using this water in the facility's operations in lieu of discharging it to the Bay.[29]

Further, the facility will also consist of a "Zero Liquid Discharge" system, which reduces the facility's waste water to solids that are managed through other means than discharge to the Bay. As a consequence, the proposed facility's operations will result in the elimination of a significant source of waste water to the Bay and avoid consuming water resources that could be used for other beneficial uses. The Air District believes these environmentally beneficial aspects of the project are important and warrant consideration in identifying the proposed facility as BACT.

Together, these load-consuming features of the facility amount to approximately an additional 9.2 MW of auxiliary load. The Applicant supplied this estimate of the auxiliary load attributable to the proposed facility's use and elimination of the City's waste water discharge based on a comparison of the Heat Balance for the proposed Russell City Energy Center, with the auxiliary load illustrated by the heat balance diagrams for three similar combined-cycle power plants, none of which conducts Title 22 waste water recycling and/or operates a Zero Liquid Discharge system.[30] Accounting for this auxiliary load would result in a "gross" Design Base Heat Rate of 6,743 Btu/kWhr (HHV) when duct firing is not occurring, which would result in emissions between 780.3 and 802.5 lbs/MWhr of CO_2E, depending upon which emissions factor is applied for CO_2. When duct firing is occurring, the "gross" Design Base Heat Rate would be 6,868 Btu/kWhr (HHV), or between 794.7 and 817.4 lbs/MWhr of CO_2E.

Installed Base Heat Rate

While the Design Rate Heat Rate reflects what the engineers aim to achieve in designing the facility, design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation. According to information provided by the Applicant, a design margin of up to 5% is typical in the commercial terms for the engineering, procurement and construction contracts for a combined-cycle power plant. Normally the performance guarantees from the combustion and steam turbine original equipment manufacturers and the contractual terms require demonstration that the project, as constructed, achieves the design output and heat rate, subject to a plus or minus 5% margin. For example, if the tested output is more than 95% of the guaranteed output, or the tested heat rate is less than 105% of guaranteed heat rate, the original equipment manufacturer and engineering, procurement and construction contractor can declare substantial completion and pay liquidated damages to compensate for the performance shortfalls.

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[29] The facility also will include a "Low Noise/Plume-Abated" cooling tower, which will consume additional load due to use of recycled waste water.

[30] The total auxiliary load indicated by the Heat Balance Diagram for Russell City Energy Center is 21.1 MW without duct firing or 24 MW with duct firing. According to the Applicant, the greater auxiliary load required for duct firing is attributable to greater condensate and feed-water flow, which requires more power for operation of pumps. In addition, the steam turbine step-up transformer will also reportedly experience greater electrical loss as more amperage flows. In comparison, the auxiliary loads for three other similarly-sized, "2x1" combined-cycle power plants operated by Calpine, Metcalf Energy Center, Osprey Energy Center and Riverside Energy Center, are approximately 12.7 MW, 12.4 MW and 12.1 MW, respectively. Email from K. Poloncarz, April 2, 2009, summarizing review of the following: *Calpine Corporation, Metcalf Energy Center, Heat Balance Diagram*, August 9, 2001; *Calpine Corporation, Osprey Energy Center, Heat Balance Diagram*, July 30, 2001; and *Calpine Corporation, Riverside Energy Center, Heat Balance Diagram*, December 11, 2001.

The Installed Base Heat Rate also represents operation of the facility when it is new and clean, but reflects the predicted range of uncertainty between the facility's design and its anticipated performance. In this case, the Applicant is making certain assumptions about the performance of the gas turbine upgrades that Siemens will perform, although it has no operating experience with these FD3 upgrades or other empirical data to back-up these assumptions. In addition to uncertainty associated with little performance data on the anticipated efficiency of the FD3 upgrades, this margin also reportedly reflects some tolerance to reflect uncertainties associated with the plant's auxiliary load, such as the potential variance between assumptions about the amount of load that will be required to conduct treatment and evaporation of the City's waste water within the facility, and actual experience. Adding this 3.3% design margin to the Design Base Heat Rate would result in an Installed Base Heat Rate of 7,080 Btu/kWhr (HHV), assuming dual unit operation without duct burner firing, corrected to ISO conditions.

Calculation of the Degraded Base Heat Rate

To establish an enforceable BACT condition that can be achieved over the life of the facility, the Air District also must account for anticipated degradation of the equipment over time between regular maintenance cycles.

Gas Turbine Heat Rate Degradation

For the gas turbines, the Applicant has assumed a rate of degradation based upon a 48,000-operating hour degradation curve, which reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5.2%.[31] According to combustion turbine manufacturers, anticipated degradation in heat rate of the gas turbines alone can be expected to increase non-linearly over time. The degradation curves relied upon by the Applicant describe the amount of "recoverable" and "non-recoverable" degradation; the former includes degradation that can be recovered through compressor water washing, filter changes, instrumentation calibration and auxiliary equipment maintenance. Id., note 2. The latter includes degradation that cannot be restored upon a maintenance overhaul. Id., note 3.

The 48,000-hour maintenance interval is based upon Siemens' recommendations, which provide detailed formulae for determining when the equipment should undergo certain inspection and maintenance activities, based upon the accumulated total for both "Equivalent Baseload Hours" and "Equivalent Starts".[32] By calculating Equivalent Baseload Hours and Equivalent Starts, the facility operator accounts for the specific operating conditions and events experienced by the facility that may impact the equipment's performance. These include the difference between baseload and peak firing hours and the impacts caused by instantaneous load changes (i.e., outside of the expected ramp rate).

The original equipment manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, because the projected 5.2% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines, the Air District has determined that,

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[31] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10, July 15, 2008, Figure 3 "Degradation Effect on Gas Turbine Heat Rate" TT-DEG-76, submitted to Air District as trade secret/confidential business information on April 2, 2009.

[32] Siemens Power Generation, Inc., Service Bulletin 36803, *Combustion Turbine Maintenance and Inspection Intervals*, Revision No. 10, October 7, 2004, submitted to the Air District as trade secret/confidential business information on April 2, 2009.

for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate. A slightly higher than average expected degradation is justified for purposes of developing an enforceable emissions limit, given Calpine's limited experience with performance of the FD3 model turbine. Adding this 6% degradation factor to the facility's "Installed Base Heat Rate" of 7,080 Btu/kWhr (HHV) (i.e., the projected heat rate of the equipment in its original condition, after accounting for a predicted 3.3% design margin) would result in a potential heat rate of 7,505 Btu/kWhr (HHV) (without duct firing).

Other Anticipated Heat Rate Degradation

In addition to the anticipated degradation of the plant's heat rate which is due to the manufacturer's anticipated degradation of the gas turbines, the Applicant also anticipates potential degradation in other elements of the combined cycle plant that will contribute to an increase in the facility's heat rate between major maintenance overhauls, as described below.

Information provided by the Applicant indicates that, according to the anticipated supplier of natural gas (PG&E), the "prevailing service delivery pressure" may fluctuate between 170 and 355 pound-force per square inch gauge (psig).[33] PG&E has proposed upgrades to the gas pipeline that should elevate the gas pressure to 250 to 410 psig. Id. Regardless what pressure the gas is when provided by PG&E, the Applicant must bring its pressure up to 500 psi and will do so by operating gas compressors. However, because of the potential range of variability in the natural gas source, the Applicant anticipates an elevated rate of degradation in the overall plant heat rate due to increased cycling of the compressor engines. Just as the frequent acceleration and deceleration characteristic of "city driving" results in increased wear and tear on the engine and decreased fuel efficiency, in comparison to driving an automobile on a highway at constant speed, so too will the plant's overall efficiency be affected by the upwards and downwards cycling of the compressor engines to accommodate this range of variation in natural gas pressure. Further, in addition to changes in natural gas pressure, the gas supply for the facility also reportedly demonstrates substantial variation in quality (in terms of its chemical constituents), according to the Applicant, which can further exacerbate degradation of the gas turbines, in the same way that using low-quality gasoline can affect an automobile's performance. This further warrants estimating the anticipated degradation rate of the turbines above the median predicted degradation rate of 5.2%.

The Applicant anticipates incurring additional heat rate degradation due to operation of the water recycling system, which will treat approximately 4 million gallons per day of waste water from the City of Hayward's adjacent treatment plant, for use in the proposed facility's operations. The Applicant's analyses report a substantial degree of variability in the water quality, which may, according to the Applicant, require additional recycling of the water supply prior to its use by the facility.[34] This would require greater load to conduct such treatment and could result in accelerated degradation of various components of the water treatment system, including pumps and rotating equipment. The same is true of the evaporator and Zero Liquid Discharge system, as well as of the plume-abated cooling towers.

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[33] Letter, Rodney Boschee, Pacific Gas & Electric, Wholesale Marketing & Business Development, to Chris Delaney, CPN Pipeline Company, subject: Calpine Russell City Energy Center, December 2, 2008, submitted to the Air District as trade secret/confidential business information on April 2, 2009.

[34] Email from K. Poloncarz to A. Crockett, April 2, 2009, attaching daily waste water monitoring results from November 1, 2008 to March 20, 2008, as provided to the Applicant by the City of Hayward, and "SummaryData, Reclaimed Water Project-2008, Final Clarifier" for sample dated April 16, 2008.

The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow of 3.75% over the 48,000 maintenance cycle.[35] This degradation in exhaust flow will result in a direct reduction in the ability of the steam turbine to generate, which will only cause further degradation in the plant's overall heat rate. While degradation in exhaust flow is expected to be partially offset by degradation in exhaust temperature (which rises over the maintenance cycle)[36], this offset will not make-up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow. Additional degradation in the HRSGs and steam turbine is expected to occur over the course of a major maintenance cycle. Additionally, the influence of a coastal environment on the air inlet filter is expected to cause additional efficiency losses, as reduced inlet air pressure affects performance of the gas turbines.

Therefore, in addition to the potential degradation in the heat rate of the gas turbines from their original condition (6%), the Applicant also predicts an additional 3% degradation in the facility's heat rate attributable to all other elements of the proposed combined-cycle facility. Adding this 3% of additional potential degradation to the anticipated heat rate degradation attributable to the gas turbines alone results in a "Degraded Base Heat Rate" for the entire combined-cycle plant of 7,730 Btu/kWhr (HHV), without duct firing.

Incentives to Maintain Equipment Efficiency

It is important to note that electric generators have obvious economic incentives to maintain and operate the equipment as efficiently as possible, so as to reduce their fuel costs. In power purchase agreements, the utility and the generator typically share the risk that the anticipated degradation or performance will depart significantly from the parties' expectations when establishing the commercial terms of the agreement. In those cases, where performance is better than anticipated, the generator may receive a bonus; where performance is worse than anticipated, the penalty is typically liquidated damages of some amount. However, in establishing enforceable permit conditions, the Air District cannot simply refer to the commercial terms negotiated between an electric generator and utility; the liquidated damages or bonuses provided by those terms are fundamentally different than the legal obligation to comply with emissions limits, at risk of civil penalty or criminal sanction.

The economic drivers for generators to achieve the highest efficiency from their equipment will only be enhanced by the implementation of a "cap-and-trade" system for emissions of greenhouse gases, as proposed by the California Air Resources Board pursuant to AB 32. Generators will need to obtain adequate allowances to cover their emissions for each compliance period; the generator who operates more efficiently will have to obtain fewer allowances in what is likely to be an auction or secondary market for emissions allowances.

As suggested by some comments, the Air District cannot depend upon market dynamics alone to assure that the facility continues to achieve the level of performance that informs the BACT determination. For that reason, the BACT determination must be enforceable as a practical matter through permit conditions that assure compliance over time. There are a number of ways this could be done.

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[35] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10, July 15, 2008, Figure 4 "Degradation Effect on Gas Turbine Exhaust Flow," TT-DEG-77, submitted to Air District as trade secret/confidential business information on April 2, 2009.

[36] *Id*., EC-93208-R10, July 15, 2008, Figure 5, "Degradation Effect on Gas Turbine Exhaust Temperature" TT-DEG-78, submitted to Air District as trade secret/confidential business information on April 2, 2009.

Mass Limits on Emissions of Greenhouse Gases

In this case, the Air District has decided to impose limits on the facility's emissions of CO_2, methane (CH_4) and nitrous oxides (N_2O), as calculated in accordance with the methods adopted both by the California Air Resources Board's mandatory reporting rules for greenhouse gas emissions, as well as by the proposed federal mandatory reporting rule. The Air District has decided that, for purposes of assuring consistency with existing reporting regimes for greenhouse gas emissions, it makes best sense to align the permit conditions with prevailing methods for calculation and inventorying of greenhouse gas emissions. Accordingly, the facility will be required to demonstrate compliance with the following mass greenhouse gas emissions limits by recording its fuel usage data and application of the specific emissions factors described below. These mass emissions limits include the emissions occurring during transient or partial load operation, including startup and shutdowns, and from both baseload generating capacity (i.e., without duct firing) and peaking capacity (i.e., with duct firing).

Averaging Time	Permitted Heat Input (MMBtu)	CO_2 Metric Tonnes	CH_4 Metric Tonnes	N_20 Metric Tonnes	CO_2E Metric Tonnes
1-Hour	4,477.2	242	0.08	0.14	242
24-Hour	107,452.0	5,797	2.03	3.33	5,802
Annual	35,708,858.0	1,926,399	675	1,107.48	1,928,182

For CO_2, emissions will be calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, the emissions are calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively, and then converted into CO_2E by application of their respective global warming potential of 21 and 310, based upon the Air Resources Board's mandatory reporting rule.

Monitoring and Reporting for Compliance with BACT Limits

The facility will be required to report upon its compliance with the foregoing mass emissions limits on a monthly basis, using the emissions factors set forth above to quantify the clock-hour, calendar day and rolling twelve calendar-month emissions for each of CO_2, CH_4, N_2O and CO_2E.

Consideration of Continuous Emissions Monitoring System for Carbon Dioxide

The Air District considered whether emissions of CO_2 should be monitored through use of stack testing and/or by a continuous emissions monitoring system (CEMS). While the Air District acknowledges that Part 75 and, as a consequence, the Air Resources Board's mandatory reporting rule allow the facility to measure CO_2 as a diluent gas, rather than oxygen (O_2), and use these data as the basis for the required reports, there is no substantial justification for obtaining direct measurements of CO_2 in the effluent stream, as there is for other pollutants. Rather, as explained previously, CO_2 is an unavoidable byproduct of the combustion process; the amount of carbon within the fuel will all ultimately be emitted as CO_2.

Unlike emissions of NO_x or carbon monoxide, which are heavily influenced by the conditions in which combustion occurs and can be controlled by adjusting those conditions (e.g., combustion temperature, amount of air present in combustion chamber), CO_2 emissions are not influenced by the conditions of combustion. Therefore, while measurements of actual stack gas concentrations of NO_x are generally more accurate than application of emissions factors, the Air District does not believe there is any apparent reason why direct measurements of CO_2 in the stack gas should be any more accurate than calculation of CO_2 through application of the relevant emissions factor to fuel usage data. Rather, to the extent that the monitoring and analytical methods for stack gas measurement of CO_2 are subject to a greater range of variability than the metering devices employed for measurement of fuel usage, calculation of CO_2 as a function of fuel usage may, in fact, be more accurate than conducting actual stack tests. The relative accuracy of CO_2 monitors is typically 10%;[37] the accuracy of test instrumentation for purposes of measuring heat rate and capacity, as described below, is typically 1.5%.[38] Thus, for purposes of quantifying the facility's mass emissions of CO_2, the Air District is not requiring actual stack gas measurements of the concentrations of CO_2 in the effluent stream. In the interest of maintaining consistency in the methods for monitoring and reporting greenhouse gases emissions, the Air District will also not require stack testing for CH_4 or N_2O.

Annual Heat Rate Performance Test

Although the mass emissions limits will be stated in pounds of the individual pollutants and in carbon dioxide equivalents (CO_2E), the Air District's BACT determination is based upon a Design Base Heat Rate for the facility of 6,852 Btu/kWhr (net) (HHV) and 6,743 Btu/kWhr (gross) (HHV), assuming baseload operation of both units, i.e., without duct firing, corrected to ISO conditions. Depending upon which greenhouse gas reporting system's emissions factor for CO_2 is applied, this would translate as approximately 792.9 to 815.5 lbs/MWhr CO_2E (net), or 780.3 to 802.5 lbs/MWhr CO_2E (gross).

As observed by some commenters, the Air District should impose an "output-based" limitation on the facility's emissions of greenhouse gases, rather than one calculated merely by tracking fuel usage, to assure the equipment is maintained and operated in a manner that retains the predicted plant efficiency level which served as the basis of the BACT determination. In response to these comments, the Air District is requiring the facility to perform an annual compliance demonstration to assure that it continues to achieve anticipated plant efficiencies over time. For this purpose, the Air District has imposed a condition requiring a "Heat Rate Performance Test", using the industry accepted method for heat rate and capacity testing, the American Society of Mechanical Engineers (ASME) Performance Test Code on Overall Plant Performance (ASME PTC 46-1996)).

While the Air District acknowledges that the facility's heat rate at peak capacity (i.e., when conducting duct firing) will be higher than at baseload capacity, because the facility is only expected to operate at peak capacity for a fraction of its total operating hours and the difference in heat rate is small, the compliance demonstration will be conducted at baseload capacity. Emissions of greenhouse gases from duct burning will nevertheless be included within the facility's emissions for purposes of compliance with the hourly, daily and annual mass emissions limits described above.

Similarly, the emissions occurring during transient load operations will be accounted for in determining compliance with the mass emissions limits. It is not practical to include periods of partial or transient load operations for purposes of the compliance demonstration – whether expressed as heat rate or pounds of emissions per megawatt-hour of energy produced – given that the facility will not be generating at capacity during those periods. Nevertheless, the facility has strong economic incentives to avoid operating at transient load for any longer than necessary. It also is subject to stringent numeric limitations on its ability to operate during startup and shutdown events, as described in Section II above.

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[37] *See*, *e.g.*, 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.")

[38] American Society of Mechanical Engineers (ASME), *Performance Test Code on Overall Plant Performance*, (PTC 46-1996), December 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to steam generator").

As provided earlier, the Design Rate Heat Rate reflects what the facility is designed to achieve; real world conditions often depart from design specifications. Therefore, to account for potential equipment underperformance and short-term degradation, the Applicant has justified application of a design margin of 3.3%, which results in an Installed Base Heat Rate of 7,080 Btu/kWhr (HHV), assuming dual unit operation without duct burner firing, corrected to ISO conditions.

The Installed Base Heat Rate reflects what is achievable when the equipment is new. The facility has justified an anticipated degradation rate of six percent (6%) based upon a 48,000-operating hour degradation curve to account for both recoverable and non-recoverable degradation expected to occur in the gas turbines between major maintenance overhauls. In addition, the Applicant has also projected a three percent (3%) degradation rate to reflect anticipated degradation of all other equipment within the combined cycle plant. This results in a Degraded Base Heat Rate for the entire combined-cycle plant of 7,730 Btu/kWhr (HHV). The Air District believes that imposing an enforceable “Heat Rate Limit” on the facility, for which it must demonstrate periodic compliance during an annual performance test, will assure that the facility continues to meet the BACT standard for greenhouse gases.

The Applicant has adequately justified the basis for setting the Heat Rate Limit at 7,730 Btu/kWhr (HHV), as opposed to some lower value (e.g., closer to the Design Base Heat Hate of 6,852 Btu/kWhr (net) (HHV) and 6,743 Btu/kWhr (gross) (HHV)). No facility has previously been subject to an enforceable BACT limit on its emissions of greenhouse gases; nor has any facility, to the Air District’s knowledge, been subject to an enforceable limitation on its heat rate as part of a federal air permit. Because this represents a “first of its kind” limitation in an air permit, neither the Air District, nor the Applicant, has relevant performance data which might provide a basis for concluding that a lower Heat Rate Limit can consistently be met over time. An enforceable BACT limitation must be set at a level that the facility can achieve for the life of the facility, including as its equipment ages and incurs anticipated degradation. At the same time, the Air District believes the proposed Heat Rate Limit is stringent enough to assure that the facility operator will not allow the equipment to incur undue or extraordinary efficiency losses through deferral of necessary maintenance, such that the assumptions which supported this BACT determination are no longer valid.

The annual compliance demonstration for this Heat Rate Limit will be conducted in accordance with ASME PTC 46-1996 and a test plan, submitted to the Air District for its review and approval at least thirty (30) days in advance of the proposed test. As suggested above, the test will be conducted without duct burning at baseload. The Applicant shall conduct this test within ninety (90) days of initial commercial operation of the facility and annually thereafter. The test will consist of three (3) one-hour test periods, conducted over three (3) consecutive-hour periods. The results of each test run will be averaged and then corrected back to ISO Conditions of:

- Ambient Dry Bulb Temperature: 59°F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,866 Btu/lb
- Fuel HHV/LHV Ratio: 1.1099

To determine compliance with this condition, the result of this test will be compared to the Heat Rate Limit of 7,730 Btu/kWhr (HHV), allowing a 1.5% compliance margin to account for the relative accuracy of test instruments, as prescribed by ASME PTC 46.

Greenhouse Gas Emissions from Other Sources at the Proposed Facility

The Air District received comments indicating that the other sources of emissions at the proposed facility were subject to BACT and needed to include BACT-equivalent emissions limits in the final permit. Of these other sources, the only ones that will emit greenhouse gases are the diesel fire pump (through combustion of fuel) and the circuit breakers (as a result of fugitive emissions of SF6).

Diesel Fire Pump

As noted by the Statement of Basis for this source, the emergency diesel fire pump is intended for use in the case of an emergency to provide water to fight fires. Its only use is to pressurize a fire suppression system. The Air Resources Board's Airborne Toxic Control Measure for Stationary Compression-Ignition Engines[39] limits its operation to emergencies and no more than 50 hours per year for inspection, maintenance and testing, which is typically done to meet the requirements of National Fire Protection Association (NFPA) standards.

As noted by the Statement of Basis, the design of a diesel engine is dictated by the manufacturer, not by the end-user. As such, the Applicant is limited to commercially available options, which include those engines meeting EPA Tier 2 requirements. According to the Statement of Basis, there are no Tier 3 or Tier 4 engines currently available that can serve the facility's emergency fire service needs. Statement of Basis, at 55. Direct-drive fire pump engines of the type proposed for the source are designed differently than other stationary or off-road diesel-fueled engines; i.e., they must meet stringent NFPA standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types instrumentation and control and exhaust systems. Id.

Consistent with its rationale for the BACT determination for greenhouse gas emissions from the combined cycle power plant, the Air District believes that BACT for this source involves selection of the most efficient stationary fire pump engine that can meet the facility's needs. The applicant provided information on the emissions from the specified diesel fuel pump engine, indicating that it has a fuel consumption rate of 14.0 gallons per hour. This appears to compare favorably with fuel consumption information available on comparable-sized fire pump engines. The Applicant has estimated total greenhouse gas emissions from the fire pump at 7.6 tons CO_2E per year.

The Air District is unaware of any more fuel efficient alternative to a Tier 2-certified engine for this purpose. Further, because emissions of greenhouse gases are directly correlative to operation of the unit, the Air District finds that BACT requires that the engine shall only be operated during emergencies and other periods authorized by the Airborne Toxics Control Measure.

Because operation of this source is already limited by the Draft Permit to no more than 50 hour per year for reliability-related activities and the Applicant is already required to keep records of the operation of this source and its fuel usage, the Air District believes no additional conditions are required to enforce this BACT determination. However, the Air District will require that the Applicant include emissions from the diesel fire pump in its facility-wide emissions of greenhouse gases, for purposes of demonstrating compliance with a facility-wide limit, as described below.

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[39] 17 California Code of Regulations §§ 93115 *et seq.*

Emissions of Sulfur Hexafluoride (SF_6) from Circuit Breakers

In addition to emissions of greenhouse gases from the combined-cycle power plant and the emergency diesel back-up generator, the proposed facility will also consist of high-voltage circuit breakers which use sulfur hexafluoride (SF_6) as a gaseous dielectric. SF_6 is the most highly potent greenhouse gas, with a "global warming potential" over a 100-year period 23,900 times greater than carbon dioxide (CO_2) and an estimated persistence in the atmosphere for 3,200 years.[40]

Because of SF_6's high global warming potential, the California Air Resources Board (Air Resources Board) has promulgated one "discrete early action" item addressing emissions of SF_6 from sources outside of the electric generating and semiconductor sectors.[41] The Air Resources Board is also scheduled to develop an additional "early action" measure specifically focused on achieving reductions in SF_6 emissions from the electrical generating sector.[42]

While there are no mandatory rules regulating electric sector emissions of SF_6 at this time, the U.S. Environmental Protection Agency (EPA) has, since 1999, led a voluntary public-private partnership known as the "SF_6 Emission Reduction Partnership for Electric Power Systems" ("EPA SF_6 Partnership"), which has targeted reductions in SF_6 emissions within the electric utility industry, tracks utilities' progress towards achieving those reduction goals, and shares information among members on their respective efforts to achieve reductions.[43] As part of these efforts, EPA has estimated an upper and lower bound weighted-average leakage rate for SF_6 from circuit breakers of 2.5% and 0.2%.[44]

The Applicant's facility will include a switchyard with five circuit breakers, each containing approximately 145 pounds of SF_6 in a sealed-pressure system.[45] According to EPA's research, emissions from circuit breakers can be easily tracked by the occurrence of "top-ups", i.e., the replacement of lost SF_6 with new product."[46]

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[40] Letter, David, Mehl (California Air Resources Board, Manager, Energy Section), *Re: Sulfur Hexafluoride (SF6) Emissions Survey for the Electricity Sector and Particle Accelerator Operators*, January 13, 2009, available at: http://www.arb.ca.gov/cc/sf6elec/survey/surveycoverletter.pdf.

[41] California Air Resources Board, *Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California Recommended for Board Consideration*, October 2007 (*Final Early Action Report*), at B-11; available at: http://www.arb.ca.gov/cc/ccea/meetings/ea_final_report.pdf. For information on the Air Resources Board's rulemaking for non-utility sector uses of SF_6, go to: http://www.arb.ca.gov/regact/2009/nonsemi09/nonsemi09.htm.

[42] *See* Air Resources Board, *Final Early Action Report*, supra at nt. [3], at C-60.

[43] For information on EPA's SF_6 Emission Reduction Partnership for Electric Power Systems, go to: http://www.epa.gov/electricpower-sf6/resources/index.html.

[44] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006, available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

[45] Email from K. Poloncarz to A. Crockett, April 2, 2009, transmitting copy of portions of Alston USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 10, 19.

[46] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, supra at nt. [92], at 1.

To evaluate the "best available control technology" for emissions of SF_6 from the facility, the Air District follows U.S. EPA's "top-down" methodology, as described elsewhere in the Response to Comments and the Statement of Basis for the Draft Permit.

Step 1: Identify Control Technologies for SF_6

Step 1 of the "top-down" process is to identify all control technologies.

Use of Other Gases/Substances for Insulation and Arc Quenching

The best way to control emissions of SF_6 would be to eliminate its use in the circuit breakers and substitute in its place a non-hazardous substance that does not have comparable emissions of greenhouse gases. One alternative to SF_6 would be use of a dielectric oil or an compressed air ("air blast") circuit breaker, which represented the type of breakers historically used in high-voltage installations, prior to the development of SF_6 breakers. However, according to one source, "SF_6 circuit breakers are the breaker type predominantly used in the [high-voltage] and [extremely high-voltage] range.[47]
According to the most recent report released by the EPA SF_6 Partnership, "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[48] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications.[49] While some progress has reportedly been made using mixtures of SF_6 and other inert gases (e.g., nitrogen or helium) in medium- or low-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute,"[50] for high-voltage applications.

Modern Closed-Pressure SF_6 Breakers with Leak Detection

In comparison to older SF_6 circuit breakers, modern breakers use substantially less SF_6 and are designed as a totally enclosed-pressure system. According to information provided by the Applicant, the facility will consist of five "dead tank-type" 245-kilovolt (kV) circuit breakers, each containing approximately 145 pounds of SF_6 at a pressure rating of 93 pounds per square inch (psig).[51] New circuit breakers are

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[47] Khan, Shoaib, Ghariani Ahmed, *Industrial Power Systems*, CRC Press, 2007.

[48] U.S. EPA, December 2008, *SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*, at 1; available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

[49] *See, e.g.*, Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, November 1997 (hereinafter, "*NIST Technical Note 142*"); available at: http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf; *see also* U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF_6", at 185; available at:
http://www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf

[50] T. Olsen (Manager, Siemens Power Transmission & Distribution), *Siemens Electrical Distribution Products Catalog 2006*, "Medium Voltage Equipment: Special Applications & Technical Information," at 13-29 (summarizing the results of the NIST study referenced in the preceding footnote); available at:

http://www.sea.siemens.com/SpeedFax06/Speedfax06files/06Speedfaxpdfs/06Speedfax_13/13_28-29.pdf.

[51] Alston USA Inc., *Instruction Manual-Type HGF 1012/1014,* HG12IM, Revision 0, Part 1, Page 10, 19.

typically guaranteed by the equipment vendor with leakage of no more than 1% per year (by weight).[52] Leakage is only be expected to occur as a result of circuit interruption and at extremely low temperatures not anticipated in the Bay Area. The Applicant submitted information from the manufacturer of the circuit breakers that will be used at the Project site, reporting that the breakers are designed, manufactured and factory-tested to be free of leaks and "warrant[ing] a gas leakage rate of less than 1% per year."[53] The information provided by the Applicant also indicates that each breaker will be equipped with a density monitor and alarm that triggers at a point when about 12.5 pounds of SF_6 have been released. Id.

Step 2: Eliminate Technically Infeasible Options

As indicated above, SF_6 has become the predominant insulator and arc quenching substance in circuit breakers because of its superior capabilities, in comparison to other alternatives. A National Institute of Standards and Technology Technical Note describes the benefits of SF_6 as follows:

For circuit breakers the excellent thermal conductivity and high dielectric strength of SF_6, along with its fast thermal and dielectric recovery (short time constant for increase in resistivity), are the main reasons for its high interruption capability. These properties enable the gas to make a rapid transition between the conducting (arc plasma) and the dielectric state of the arc, and to withstand the rise of the voltage. SF_6-based circuit breakers are presently superior in their performance to alternative systems such as high-pressure air blast or vacuum circuit breakers. NIST Technical Note 1425, supra nt. [9], at 3.

However, the greatest level of control for emissions of greenhouse gases would be achieved through use of circuit breakers that do not rely upon SF_6 for its insulating and arc quenching capabilities. While oil-filled or "air-blast" breakers are alternatives available for high-voltage systems, both of these options would require significantly larger equipment to replicate the same insulating and arcing capabilities of the SF_6 breakers proposed by the Applicant. According to the Applicant, the proposed project site does not have adequate space within the switchyard to accommodate oil or air-blast breakers. [Need description of size needs and available space for switchyard.]

As previously noted, the project has been proposed for location in a densely populated area because, according to the Energy Commission, the project's objectives were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices", and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[54] As a consequence, replacement of the proposed circuit breakers with breakers that do not use SF_6 is not a feasible option for this Project, given the space constraints imposed by construction of the Project on a former industrial site near a source of recycled waste water.

Based upon the Air District's review of technical literature, replacement of SF_6 with another gaseous dielectric can be eliminated at Step 2, since existing research indicates that there is no replacement gas available at this time with comparable insulating and arc quenching capabilities. Additionally, mixtures of SF_6 and another gas are not feasible because, according to one source, "[t]he use of such a mixture [e.g., with N_2] results in somewhat reduced interrupting capability relative to pure SF_6, and the breaker is often

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[52] *See supra* at nt. [96], at 1 ("Many equipment manufacturers now guarantee minimal to zero leak rates for new equipment.").

[53] Alston USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 21, Section 5.3, "SF6 Gas Policy".

[54] 2002 Energy Commission Decision, at 17.

derated by one current interrupting class."[55] Further, use of oil-filled or air-blast breakers does not qualify as a feasible alternative for the proposed project site, since there is not sufficient space at the proposed project site for location of the physically larger-sized breakers necessitated to achieve comparable arc quenching capability.

Step 3: Rank Control Technologies

In the absence of feasible alternatives to use of SF_6, the next best control would be use of a new circuit breaker that is guaranteed to leak 1% or less per year and a leak detection system. Assuming a total inventory of 725 lbs for the proposed RCEC and leakage rate of 1%, this would amount to potential emissions of SF_6 of 7.25 lbs/year, which due to SF_6's high global warming potential would equal approximately 78.6 metric tonnes CO_2E per year.

Step 4: Evaluate Most Effective Controls and Economic Impacts and Document Results

Step 4 of the top-down analysis involves consideration of the ancillary energy, environmental and economic impacts associated with using the top-ranked control technologies. According to one source, one reason for selecting S_F6 over oil dielectrics is the relative predictability of decomposition products:

One advantage of S_{F6} relative to oil is that SF_6 starts out as a pure chemical, which forms a limited number of decomposition by-products as a result of reactions that can be predicted with some precision. The toxicity of the limited number of by-products can therefore be investigated and adequate precautions taken. "Oil" dielectrics, on the other hand, usually start out as "hydrocarbon soup," with far too many compounds to predict the decomposition by-products, let alone their toxicity."[56]

However, SF6, too, may produce some toxic and corrosive products as a result of electrical discharges, according to most literature.

Although use of alternative breakers which use air or oil for insulating and arc quenching was eliminated as infeasible at Step 2, it would also result in significant environmental impacts associated with the additional land needed to site the physically larger breakers near the facility, the greater amount of noise generated by air or oil-filled breakers, and the potential for release of dielectric fluid to the environment and/or associated fires. According to one study, "[S_F6] offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads." NIST Technical Note 1425, supra nt. [9], at 3. Accordingly, even if such alternatives were not eliminated at Step 2 of the top-down analysis, they would likely cause ancillary environmental impacts that warranted their elimination for the Project site.

Step 5: Select BACT

The Air District has concluded that using totally enclosed circuit breakers of the number and size proposed by the Applicant constitutes BACT for this source. The Applicant's circuit breakers will be equipped with a density alarm that provides a warning when 10% of the SF_6 (by weight) has been released, which would then trigger a "top-up" event, i.e., replacement of the lost SF_6. In light of this, the proposed facility's product purchase and use records should provide a relatively accurate process for inventorying emissions of SF_6. Based upon the Air District's review, purchase record reconciliation is the standard method for measuring and reporting SF_6 emissions from circuit breakers.

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[55] Boggs, Steven, "Sulphur Hexafluoride; Introduction to the Material and Dielectric", Institute of Electrical and Electronics Engineers, Inc. (IEEE), *IEEE Electrical Insulation Magazine*, Vol. 5, No. 5, at 18, 20 (September/October 1989).

[56] *Id*., at 19.

The proposed Russell City Energy Center will already be required to report its emissions of SF_6 under the California Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas emissions, 17 Cal. Code Regs. §§ 95100 et seq. (hereinafter, "Mandatory Reporting Rule").[57] The Mandatory Reporting rule requires that electric generating facilities report, "[f]ugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order." 17 Cal. Code Regs. § 95111(a)(1)(J). Russell City Energy Center might possibly exclude such emissions from the reports it submits to the Air Resources Board if they met the criteria for a de minimis emissions source, i.e., one that represents less than 3% of the facility's total CO_2E emissions, not to exceed 20,000 metric tonnes CO_2E. 17 Cal. Code Regs. § 95103(a)(6). However, the Applicant has agreed that, for purposes of satisfying the BACT standard, it will report emissions of SF_6 for Russell City Energy Center. The Mandatory Reporting Rule adopts the reporting protocol developed by EPA's SF_6 Partnership methodology, which requires tracking of the change in inventory, purchases/acquisitions and sales/disbursements of SF_6 and the change in total nameplate capacity. 17 Cal. Code Reg. § 95111(f). It also adopts the EPA SF_6 Partnership's reporting protocol form, which appears at Appendix A-21.

The Final Permit includes an annual limit on facility-wide emissions of CO_2E. To account for emissions of SF_6 and assure that they are included in an enforceable permit condition, the Applicant shall be required to limit total facility-wide CO_2E to the amounts emitted by the combined-cycle power plant, the emergency standby diesel engine and circuit breakers. This annual limit reflects potential SF_6 emissions of 1%, or about 7.25 lbs/year, which due to SF_6's high global warming potential, would equal 78.6 metric tonnes CO_2E per year. Adding the allowable emissions of greenhouse gases from the diesel fire pump engine – 7.6 metric tonnes CO_2E per year – results in an additional 86.2 metric tonnes CO_2E per year. As indicated above, the combined-cycle power plant will be subject to an emissions limit of 1,928,182 metric tonnes CO_2E per year. Adding the allowable emissions from these other sources results in a facility-wide maximum of 1,928,268.2 metric tonnes CO_2E per year, which the facility must demonstrate compliance with on a 12 rolling calendar-month basis.

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[57] Available at: http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf.

APPENDIX 5.1G

Mitigation and Offsets

APPENDIX 5.1G

Offset Listing-Mitigation Strategy

The Bay Area AQMD maintains a listing of its current ERC bank for public review and inspection. The ERC bank listing can be obtained from the AQMD's website, and is not included herein. The OGS project, pursuant to the AQMD NSR rule is required to purchase or acquire sufficient emission reduction credits to offset the proposed project emissions due to its proposed status as a major source for NOx and POC. The NSR rule required amounts of ERCs are delineated in Table 5.1G-1, where the emissions listed are based on the first year of operation (potential to emit).

Table 5.1G-1 Cumulative emissions increases and required offsets per Regulation 2-2-215, 2-2-302, 2-2-303

Pollutant	Cumulative Offset Threshold	Offset Ratio	Cumulative Increase Since April 5, 1991	OGS Emission Rates	Cumulative Emissions Increase	Offsets Required
POC	10/35 tpy	>10 but < 35 1:1 => 35 1.15:1	29.5	29.5	29.5	29.5
NO_x	10/35 tpy	>10 but < 35 1:1 => 35 1.15:1	98.8	98.8	98.8	113.6
PM_{10}	100 tpy	If major and increase is > 1 tpy, then 1:1	76.3	76.3	76.3	0
CO	100 tpy	> 100 tpy increase Modeling plus offsets to show attainment and maintenance of standard	98.8	98.8	98.8	0
SO_2	100 tpy	If major and increase is > 1 tpy, then 1:1	12.6	12.6	12.6	0

OGS Proposed Mitigation Program

The proposed mitigation strategy for OGS is being submitted as a confidential filing under separate cover. This strategy will be finalized and approved by the BAAQMD prior to the issuance of the authority to construct for the proposed project.

BAAQMD regulations 2-2-215, 302 and 303 requires OGS to provide emission offsets (emissions reduction credits, or ERCs) when emissions exceed specified levels on a pollutant-specific basis. Section 2-2-302 requires POC and NO_x emission reduction credits to be provided at an offset ratio of 1:1 or 1.15:1 dependent upon emissions levels. Because both POC and NO_x contribute to the Bay Area Basin ozone levels, Section 2-2-302.2 allows emission reduction credits of POC's to be used to offset increased emissions of NO_x, at the required offset ratios as stated above. Section 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tpy of SO_2 and PM_{10}. As facility emissions of SO_2 and PM_{10} will be below 100 tpy, SO_2 and PM_{10} offsets are not required.

Sections 2-2-304 and 2-2-305 impose emissions offset requirements, or require project denial, if SO_2, NO_2, PM_{10}, or CO air quality modeling results indicate emissions will interfere with the attainment or maintenance of the applicable ambient air quality standards or will exceed PSD increments. For many of the pollutants and averaging periods, District regulations do not require OGS to conduct these analyses, since the modeled impacts of the proposed facility are not significant under District rules. However, modeling for these pollutants has been conducted to satisfy CEC requirements. The modeling analyses show that facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards.

The project Applicant will provide all necessary documentation to show control or ownership of the required emissions offsets prior to issuance of the facility Permit to Operate by the BAAQMD per AQMD regulation 2-2-410. Offsets may be acquired from the District bank or from other sources such as shutdowns, or non-traditional sources of emissions reductions credits.

The applicant is proposing to mitigate the increases in NO_x and POC through the purchase of banked ERCs, per the BAAQMD rules and regulations. Because the BAAQMD offset trigger levels for PM10/PM2.5 and SO_2 are at 100 tons per year per pollutant and the projects emissions are less than those levels, ERCs for these pollutants are not proposed at this time for mitigation.

In addition to providing offsets for NO_x and POC through the BAAQMD emissions bank, Radback Energy can commit to mitigate the PM10/PM2.5 and SO_2 emissions from the proposed project. The commitment is consistent with recent CEC permitting cases that provide for the mitigation of the impacts of PM10/2.5 emissions and other community public health concerns. (See the CEC decisions for the Pico Power Project, the Metcalf Energy Center, the Tracy Peaker, Tesla Power Project, Russell City Energy Center, and Chula Vista Peaker). To develop a PM10/2.5 mitigation/community benefits program that both addresses the project impacts and the environmental and public health concerns of the affected communities, the following programs could be made available:

- High efficiency street sweeping of traffic lanes on high traffic streets. RADBACK could provide funding to the city of Oakley for the purchase and operation of high efficiency street sweepers. This method would directly benefit the communities in the project area.

- Replacing wood fireplaces and wood stoves. Funding could be provided to and administered through the BAAQMD where up to $300 per fireplace and up to $500 per wood stove refunds would be provided. The program would replace wood burning fireplaces with natural gas inserts with the wood stoves being replaced with current EPA certified clean pellet stoves. This program is purely voluntary for those who wish to participate.

- Sodding or paving high traffic areas. Areas with large off-road traffic use could be paved or planted with sod to minimize particulate emissions.

- Tree planting programs.

- Providing funding to the Carl Moyer program on a dollar/ton basis that would be made available to the City for a period of 24-months. The Carl Moyer program provides incentive grants for cleaner-than-required engines, equipment and other sources of pollution providing early or extra emission reductions. Eligible projects include cleaner on-road, off-road, marine, locomotive and stationary agricultural pump engines. The program achieves near-term reductions in emissions of NOx, PM10/2.5, and reactive organic gas (ROG). Funding could be provided on a dollar per ton basis at a rate that is similar to the current ERC market rates. The funding would be directed towards local project for a period of time, after which the funding would be open to projects in the general Bay Area.

The applicant will work with the CEC to identify a mitigation strategy that best suites the needs of the project.

APPENDIX 5.1H

Cumulative Impact Support Data

APPENDIX 5.1H

Cumulative Impacts Analysis Protocol

Potential cumulative air quality impacts that might be expected to occur resulting from CCGS Project and other reasonably foreseeable projects are both regional and localized in nature. These cumulative impacts will be evaluated as follows.

Regional Impacts

Regional air quality impacts are possible for pollutants such as ozone, which involve photochemical processes that can take hours to occur. CCGS is proposing to supply emissions mitigation per Appendix 5.1G. Additional mitigation for other pollutants may be required by the CEC.

Although the relative importance of VOC and NO_x emissions in ozone formation differs from region to region, and from day to day, most air pollution control plans in California require roughly equivalent controls (on a ton per year basis) for these two pollutants. The change in emissions of the sum of these pollutants, equally weighted, will be used to provide a reasonable estimate of the impact of CCGS on ozone levels. The net change in emissions of ozone precursors from CCGS will be compared with emissions from all sources within the Bay Area Air Basin (Table 5.1H-1).

Table 5.1H-1 Estimated Bay Area Air Basin Emissions Inventory for 2008 (tons/day)

Source Category	**TOG**	**ROG**	**CO**	**NO_x**	**SO_x**	**PM10**	**PM2.5**
Total Stationary Sources	614.6	106.6	44.3	50.6	45.9	16.3	12.1
Total Area Sources	173.5	87.9	161.9	16.9	0.6	175.5	52.9
Total Mobile Sources	200.7	183.1	1541.5	380.5	14.9	20.3	16.3
Total Natural Sources	116.1	106.5	49.4	1.6	0.5	5.1	4.3
Air Basin Totals	*1105*	*484*	*1797*	*450*	*62*	*217*	*86*

Source: CARB, June 2009

Air quality impacts of fine particulate, PM10 and/or PM2.5, have the potential to be either regional or localized in nature. On a regional basis, an analysis similar to that proposed above for ozone will be performed, looking at the three pollutants that can form PM_{10} in the atmosphere, i.e., VOC, SO_x, and NO_x as well as at directly emitted particulate matter. BAAQMD regulations require offsets to be provided for NOx and VOC emissions from the project, i.e., the net increase in emissions must be mitigated.

As in the case of ozone precursors, emissions of PM10/2.5 precursors are expected to have approximately equivalent ambient impacts in forming PM10/2.5, per ton of emissions on a regional basis. Table 5.1H-2 provides the comparison of emissions of the criteria pollutants from CCGS with emissions from all sources within Bay Area Air Basin as a whole.

Table 5.1H-2 Comparison of CCGS Project Emissions to Estimated Inventory for 2008

Category	TOG	ROG[1]	CO	NO_x	SO_x	PM10	PM2.5
CCGS Emissions (tons/yr)	-	30	96	99	13	42	42
CCGS Emissions (tons/day)	-	0.082	0.263	0.271	0.036	0.115	0.115
BA Air Basin Total (tons/day)	1105	484	1797	450	62	217	86
CCGS % of Air Basin Total Tons/day basis	**-**	**0.017**	**0.015**	**0.06**	**0.058**	**0.053**	**0.134**

[1] CCGS VOC emissions compared to inventory ROG emissions.

Localized Impacts

Localized impacts from CCGS could result from emissions of carbon monoxide, oxides of nitrogen, sulfur oxides, and directly emitted PM10/2.5. A dispersion modeling analysis of potential cumulative air quality impacts will be performed for all four of these pollutants.

In evaluating the potential cumulative localized impacts of CCGS in conjunction with the impacts of existing power generation facilities immediately adjacent to the project site and facilities not yet in operation but that are reasonably foreseeable, a potential impact area in which cumulative localized impacts could occur was identified as an area with a radius of 8 miles around the plant site. Based on the results of the proposed air quality modeling analyses described above, "significant" air quality impacts, as that term is defined in federal air quality modeling guidelines, will be determined. If the project's impacts do not exceed the significance levels, no cumulative impacts will be expected to occur, and no further analysis will be required. Otherwise, in order to ensure that other projects that might have significant cumulative impacts in conjunction with CCGS are identified, a search area with a radius of 8 miles beyond the project's impact area will be used for the cumulative impacts analysis. Within this search area, three categories of projects with emissions sources will be used as criteria for identification:

- Projects that have been in operation for a sufficient time period, and whose emissions are included in the overall background air quality data.
- Projects which recently began operations whose emissions may not be reflected in the ambient monitoring background data.
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

The applicable inclusion dates for each of the above source categories will be discussed and approved by the BAAQMD staff. The requested source listings will incorporate these dates. Projects that are existing, and that have been in operation such that their emissions are reflected in the ambient air quality data that has been used to represent background concentrations require no further analysis. The cumulative impacts analysis adds the modeled impacts of selected facilities to the maximum measured background air quality levels, thus ensuring that these existing projects are taken into account.

Projects for which air pollution permits to construct have been issued but that were not operational will be identified through a request of permit records from the BAAQMD. The search will be requested to extend outwards to 8 miles from the project site.

Given the potentially wide geographic area over which the dispersion modeling analysis is to be performed, the AERMOD model will be used to evaluate cumulative localized air quality impacts. The detailed modeling procedures, AERMOD options, and meteorological data used in the cumulative impacts dispersion analysis were the same as those described in Section 5.1. The receptor grid will be the same one that was used to assess this project.

Cumulative Impacts Dispersion Modeling

The dispersion modeling analysis of cumulative localized air quality impacts for the proposed project will be evaluated in combination with other reasonably foreseeable projects and air quality levels attributable to existing emission sources, and the impacts were compared to state or federal air quality standards for significant impact. As discussed above, the highest second-highest modeled concentrations will be used to demonstrate compliance with standards based on short-term averaging periods (24 hours or less).

Supporting information to be used in the analysis includes the following:

- 2008 estimated emissions inventory for Bay Area Air Basin (Table 5.1H-1);
- List of projects resulting from the screening analysis of permit files by the BAAQMD;
- Table delineating location data of sources included in the cumulative air quality impacts dispersion modeling analysis;
- Stack parameters for sources included in the cumulative air quality impacts dispersion modeling analysis; and
- Output files for the dispersion modeling analysis.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
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APPLICATION FOR CERTIFICATION
FOR THE ***OAKLEY GENERATING STATION***

Docket No. 09-AFC-4
PROOF OF SERVICE
(Revised 2/4/2010)

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DECLARATION OF SERVICE

I, Mary Finn, declare that on April 7, 2010, I served and filed copies of the attached Oakley Generation Station Project Supplemental Filing of Air Quality & Public Health revised April 7, 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/contracosta/index.html].** The document has 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, California 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:

__x__ **sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (preferred method);**

OR

_____depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-4
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I declare under penalty of perjury that the foregoing is true and correct.

Mary Finn