5.1 Air Quality

The Lodi Energy Center (LEC) will be a combined-cycle nominal 255-megawatt (MW) power generation facility consisting of a "Rapid Response" GE Energy Frame 7FA, natural gas-fired turbine-generator, a single condensing steam turbine (STG), a 7-cell cooling tower, and associated balance-of-plant equipment. The facility will be located in Lodi, San Joaquin County, California, on a 4.4-acre parcel located adjacent to the City of Lodi's White Slough Water Pollution Control Facility (WPCF) and the existing Northern California Power Agency (NCPA) Combustion Turbine Project #2 (STIG plant).

This section describes existing air quality conditions, maximum potential impacts from the project, and mitigation measures that keep these impacts below thresholds of significance. The project will use clean and efficient combined-cycle generation technology to generate electricity in a manner that will minimize the amount of fuel needed, emissions of criteria pollutants, and potential effects on ambient air quality.

Other beneficial environmental aspects of the project that minimize adverse air quality impacts include the following:

- Clean-burning natural gas as fuel
- Selective catalytic reduction (SCR) and dry low NO_x combustors to minimize NO_x emissions
- Oxidation catalyst to reduce carbon monoxide emissions
- Inlet air filters and lube oil vent filters to minimize particulate emissions
- Appropriately sized stack to reduce ground-level concentrations of exhaust constituents

This section presents the methodology and results of the air quality analyses performed to assess potential impacts associated with air emissions from the construction and operation of the project. Potential public health risks posed by emissions of non-criteria pollutants are addressed in Section 5.9 (Public Health).

Section 5.1.1 describes the affected environment. Section 5.1.2 provides a detailed description of the project. Section 5.1.3 provides an evaluation of emissions from the proposed project, while Section 5.1.4 discusses the best available control technology determination. Section 5.1.5 describes the air quality impact analysis and mitigation measures. Section 5.1.6 presents applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.7 presents agency contacts, permit requirements and schedules. Section 5.1.8 contains references cited or consulted in preparing this section.

5.1.1 Affected Environment

5.1.1.1 Geography and Topography

The project site is within a 1,040-acre parcel owned by and incorporated in the City of Lodi. This incorporated parcel is not contiguous with the City of Lodi, which is approximately 6 miles to the east. The proposed site parcel is approximately 4.4 acres adjacent to the City of Lodi's White Slough WPCF to the east, treatment and holding ponds associated with the

WPCF to the north, the existing STIG plant to the west, and a vector control facility to the south. Also south of the project site is Dredger Cut, which discharges into White Slough at the confluence with Bishop Cut.

The project site is nearly level, at an elevation approximately at sea level. Essentially flat terrain extends for many miles on all sides of the project site. The project site is located in the San Joaquin Valley Air Pollution Control District (SJVAPCD).

5.1.1.2 Climate and Meteorology

The climate of the San Joaquin Valley is characterized by hot summers, mild winters, and small amounts of precipitation. The major climatic controls in the Valley are the mountains on three sides and the semi-permanent Pacific High pressure system over the eastern Pacific Ocean. The Great Basin High pressure system to the east also affects the Valley, primarily during the winter months. These synoptic scale influences result in distinct seasonal weather characteristics, as discussed below.

The Pacific High is a semi-permanent subtropical high-pressure system located off the Pacific Coast. It is centered between the 140°W and 150°W meridians, and oscillates in a north-south direction seasonally. During the summer, it moves northward and dominates the regional climate, producing persistent temperature inversions and a predominantly southwesterly wind field. Clear skies, high temperatures, and low humidity characterize this season. Very little precipitation occurs during summer months, because migrating storm systems are blocked by the Pacific High. Occasionally, however, tropical air moves into the area and thunderstorms may occur over the adjacent mountains.

In the fall, the Pacific High weakens and shifts southwestward toward Hawaii, and its dominance is diminished in the San Joaquin Valley. During the transition period, the storm belt and zone of strong westerly winds also moves southward into California. The prevailing weather patterns during this time of year include storm periods with rain and gusty winds, clear weather that can occur after a storm or because of the Great Basin High pressure area, or persistent fog caused by temperature inversion.

Precipitation and temperature data have been recorded at the meteorological monitoring station located in Lodi, approximately 5.7 miles east-northeast of the project site. In summer (June, July, and August), daily high and low temperatures at the project area average 89.7 and 55.0°F (degrees Fahrenheit), respectively. In winter (December, January, and February), daily high and low temperatures are about 56.6 and 38.8°F, respectively.[1] The average annual rainfall at the project site is about 17.6 inches, of which about 81% occurs between November and March. Between rainstorms, skies are fair, winds are light, and temperatures are moderate.

Air quality is determined primarily by the type and amount of pollutants emitted into the atmosphere, the topography of the air basin, and local meteorological conditions. In the project area, stable atmospheric conditions and light winds can provide conditions for pollutants to accumulate in the air basin when emissions are produced. The predominant winds in California are shown in Appendix 5.1B, Figures 5.1B-1A through 5.1B-1D. As

1 Desert Research Institute, Western Regional Climate Center. 2008. Western U.S. Climate Historical Summaries, Site Accessed May 2008. URL: http://www.wrcc.dri.edu/Climsum.html

indicated in the figures, winds in California generally are light and easterly in the winter, but strong and westerly in the spring, summer, and fall.

Wind speed and wind direction data have been recorded at the meteorological monitoring station at the Stockton Metropolitan Airport. This station is located approximately 16 miles to the south-southeast, and is considered representative of meteorological conditions in the project area. Quarterly wind roses and wind frequency distribution tables are provided in Appendix 5.1B. Wind patterns at the project site can be seen in Appendix 5.1B, Figures 5.1B-2A through 5.1B-6E, which show quarterly and annual wind roses for meteorological data collected at the Stockton Metropolitan Airport meteorological station during 2000 through 2004. The annual wind rose for 2004 is typical for this location and is shown as Figure 5.1-1. It can be seen that the winds are mild (12.8 percent calm conditions) and predominantly from the northwestern quadrant. On an annual basis, approximately 57.6 percent of the winds come from the west through north-northwest. Winds are predominantly from the northwest and southeast during the first quarter, from the west during the second quarter, from the northwest during the third quarter, and from the southeast during the fourth quarter. Southeasterly winds develop mainly during the first and fourth quarters and are essentially absent during the other quarters.

The mixing heights of the area are affected by the eastern Pacific high-pressure system and marine influences. Often, the base of the inversion is found at the top of a layer of marine air, because of the cooler nature of the marine environment. Smith, et al, (1984) reported that at Oakland, the nearest upper-level meteorological station (located approximately 50 miles west-southwest of the project site), 50th percentile morning mixing heights for the period 1979–80 were on the order of 1,770 feet (530 to 550 meters) in summer and fall, and 3,600 to 3,900 feet (1,100 to 1,200 meters) in winter and spring. The 50th percentile afternoon mixing heights ranged from 2,150 and 3,030 feet (660 to 925 meters) in summer and fall, and over 3,900 feet (over 1200 meters) in winter and spring. Such mixing heights provide generally favorable conditions for the dispersion of pollutants. Inland areas, where the marine influence is weaker, often experience strong ground-based inversions during cold weather periods. These inversions inhibit dispersion of low-lying sources of air pollution, such as cars, trucks and buses, and can result in high pollutant concentrations.

5.1.1.3 Criteria Pollutants and Air Quality Trends

5.1.1.3.1 State and National Air Quality Standards

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. In addition, the California Air Resources Board (CARB) has established standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases. Areas with air pollution levels above these standards can be considered "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements. The attainment status of the San Joaquin Valley air basin with respect to federal and state standards is summarized in Table 5.1-1.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 5.1-2 presents the NAAQS and California ambient air quality standards for selected pollutants. The California standards are generally set at concentrations much lower than the federal standards and in some cases have shorter averaging periods.

TABLE 5.1-1
San Joaquin Valley Attainment Status

Pollutant		California [a]	National [b]
Ozone	1 hour	Nonattainment/Severe	No Federal Standard
	8 hours	Nonattainment	Nonattainment/Serious[e]
Carbon Monoxide		Attainment/Unclassified	Attainment/Unclassified
Nitrogen Dioxide		Attainment	Attainment/Unclassified
Sulfur Dioxide		Attainment	Attainment/Unclassified
Suspended Particulate Matter (10 Microns)		Nonattainment	Nonattainment/Serious[c]
Suspended Particulate Matter (2.5 Microns)		Nonattainment[d]	Nonattainment
Sulfates		Attainment	No Federal Standard
Lead		Attainment	No Designation/Classification
Hydrogen Sulfide		Unclassified	No Federal Standard
Vinyl Chloride		Attainment	No Federal Standard

[a]CCR Title 17, Sections 60200-60210

[b]40 CFR Part 81

[c]Although EPA has determined that the San Joaquin Valley Air Basin has attained the federal PM10 standards (71 FR 63641; October 30, 2006), its determination does not constitute a redesignation to attainment per section 107(d)(3) of the federal Clean Air Act. EPA has proposed to redesignate the San Joaquin Valley Air Basin as attainment for PM10 (73 FR 22307; April 25, 2008), but this proposal has not become final because the public comment period just ended on June 10, 2008 (73 FR 30029).

[d]The Valley is designated nonattainment for the 1997 PM2.5 federal standards. EPA designations for the 2006 PM2.5 standards will be finalized in December 2009. SJVAPCD has determined, based on the 2004-06 PM2.5 data, that the Valley has attained the 1997 24-hour PM2.5 standard.

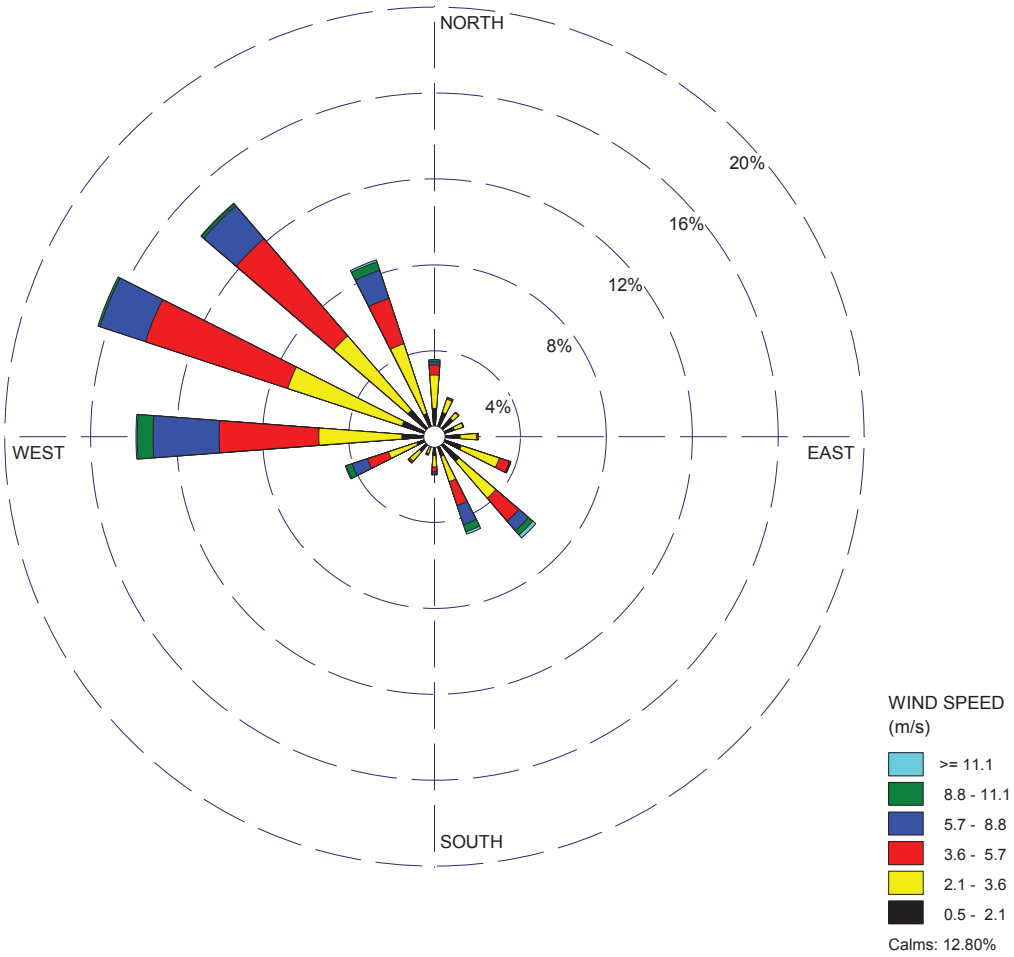
[e]On April 30, 2007, the Governing Board of SJVAPCD voted to request EPA to reclassify the San Joaquin Valley Air Basin as extreme nonattainment for the federal 8-hour ozone standard. The California Air Resources Board, on June 14, 2007, approved this request. This request has been forwarded to EPA by the California Air Resources Board and would become effective upon EPA final rulemaking after a notice and comment process; it is not yet in effect.

WIND ROSE PLOT:

Stockton, CA - 2004
January 1, 2004 through December 31, 2004

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **12.80%**	TOTAL COUNT: **8398 hrs.**	
	AVG. WIND SPEED: **3.52 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 5.1-1
2004 ANNUAL WIND ROSE, STOCKTON, CALIFORNIA
LODI ENERGY CENTER
LODI, CALIFORNIA

TABLE 5.1-2
Ambient Air Quality Standards

Pollutant	Averaging Time	California	National
Ozone	1 hour	0.09 ppm	—
	8 hours	0.070 ppm	0.075 ppm
Carbon Monoxide	8 hours	9 ppm	9 ppm
	1 hour	20 ppm	35 ppm
Nitrogen Dioxide	Annual Average	0.030 ppm	0.053 ppm
	1 hour	0.18 ppm	—
Sulfur Dioxide	Annual Average 24 hours	— 0.04 ppm (105 µg/m^3)	0.03 ppm (80 µg/m^3) 0.14 ppm (365 µg/m^3)
	3 hours 1 hour	— 0.25 ppm (655 µg/ m^3)	0.5 ppm (1300 µg/m^3)* —
Suspended Particulate Matter (10 Micron)	24 hours	50 µg/m^3	150 µg/m^3
	Annual Arithmetic Mean	20 µg/m^3	—
Suspended Particulate Matter (2.5 Micron)	Annual Arithmetic Mean	12 µg/m^3	15 µg/m^3 (3-year average)
	24 hours	none	35 µg/m^3 (3-year average of 98th percentiles)
Sulfates	24 hours	25 µg/m^3	—
Lead	30 days	1.5 µg/m^3	—
	Calendar Quarter	—	1.5 µg/m^3
Hydrogen Sulfide	1 hour	0.03 ppm	—
Vinyl Chloride	24 hours	0.01 ppm	—
Visibility Reducing Particles	8 hours (10 a.m. to 6 p.m. PST)	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.	—

*This is a national secondary standard, which is designed to protect public welfare.

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

5.1.1.3.2 Ambient Monitoring Stations

Data from two ambient air monitoring stations were used to characterize air quality at the project site. They were chosen because of their proximity to the site and because they record area-wide ambient conditions rather than the localized impacts of any particular facility. All ambient air quality data presented in this section were taken from CARB publications and data sources or EPA air quality data tables. Ambient concentrations of ozone, carbon monoxide (CO), nitrogen dioxide (NO_2), respirable particulate matter (PM_{10}), fine particulate matter ($PM_{2.5}$), sulfates, and lead are recorded at the Hazelton Avenue monitoring station in Stockton,

about 3.6 miles from the project site. The nearest monitoring station for SO_2 is at Bethel Island, about 15 miles from the project site. Monitoring of lead ended in 2003. The Stockton-Hazelton monitoring station is operated by the California Air Resources Board and the Bethel Island monitoring station is operated by the Bay Area AQMD.

5.1.1.3.3 Ozone

Ozone is an end-product of complex reactions between volatile organic compounds (VOC) and NO_x in the presence of intense ultraviolet radiation. VOC and NO_x emissions from millions of vehicles and stationary sources, in combination with daytime wind flow patterns, mountain barriers, a persistent temperature inversion, and intense sunlight result in high ozone concentrations. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is a nonattainment area for ozone.

Maximum ozone concentrations at the Stockton-Hazelton monitoring station are usually recorded during the summer months. Table 5.1-3 shows the annual maximum one-hour and eight-hour ozone levels recorded at this station in Stockton during the period from 1998–2007, as well as the number of days in which the state and federal standards were exceeded. The data show that the state ozone air quality standard was frequently exceeded during all years except in 2007. The federal 8-hour standard was also exceeded from time to time in six of the 10 years shown.

The long-term trends of maximum one-hour ozone readings are shown in Figure 5.1-2 for the Stockton-Hazelton monitoring station in Stockton. The data show that compliance with the state ozone air quality standards has not been achieved in the area in the past 13 years. Trends of maximum and 3-year averages of the 4th highest daily concentrations of 8-hour average ozone readings[2] at the Stockton-Hazelton station are shown in Figure 5.1-3. These levels are above the new 2008 federal 8-hour average standard (0.075 $\mu g/m^3$) during the 11 years shown (1997-2007), except during period 2002-2005 for the 3-year average of the 4th highest daily concentration.

TABLE 5.1-3
Ozone Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-Hour Average	0.126	0.114	0.107	0.103	0.102	0.104	0.096	0.099	0.109	0.093
Highest 8-Hour Average	0.100	0.108	0.080	0.088	0.081	0.088	0.080	0.086	0.092	0.081
Number of Exceeding:										
State Standard (0.09 ppm, 1-hour)	10	6	4	5	2	3	1	3	6	0
Federal Standard (0.08 ppm, 8-hour)	4	4	0	1	0	1	0	1	3	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

Note: The 1997 federal ozone standard has been replaced by the new 2008 standard of 0.075 ppm. A EPA final rule on the ozone standard became effective May 27, 2008.

[2] The federal 8-hour ozone standard is based on this statistic.

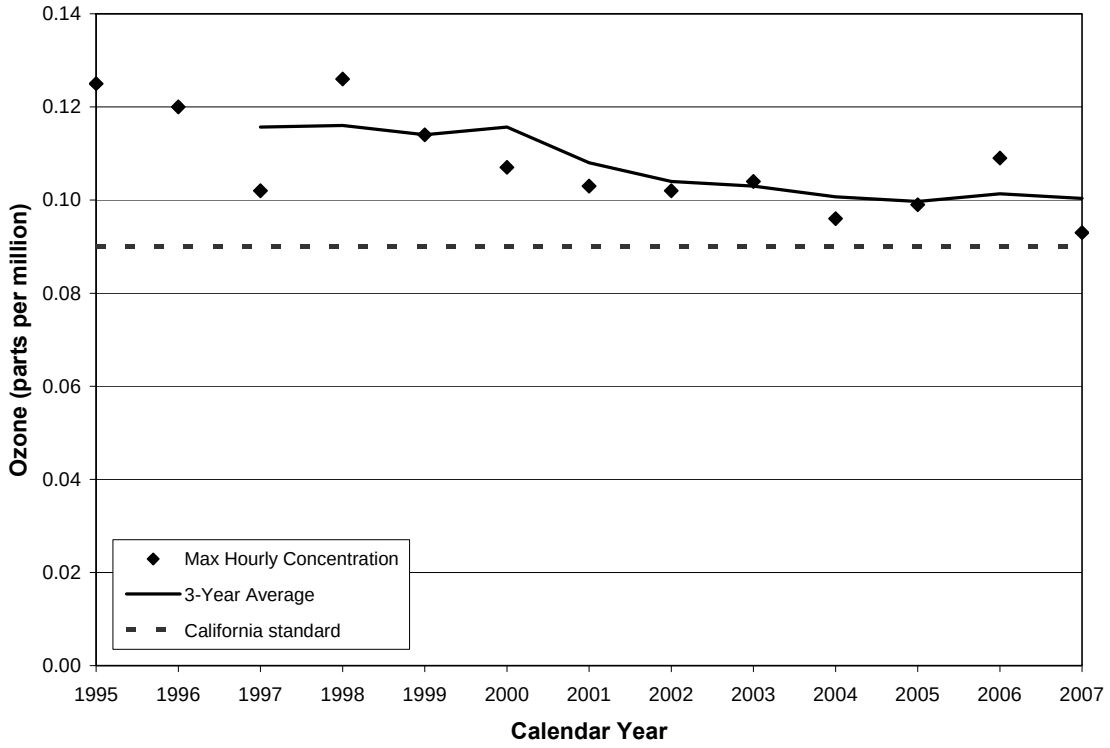


FIGURE 5.1-2
Maximum 1-hour Ozone Level: Stockton-Hazelton: 1995-2007

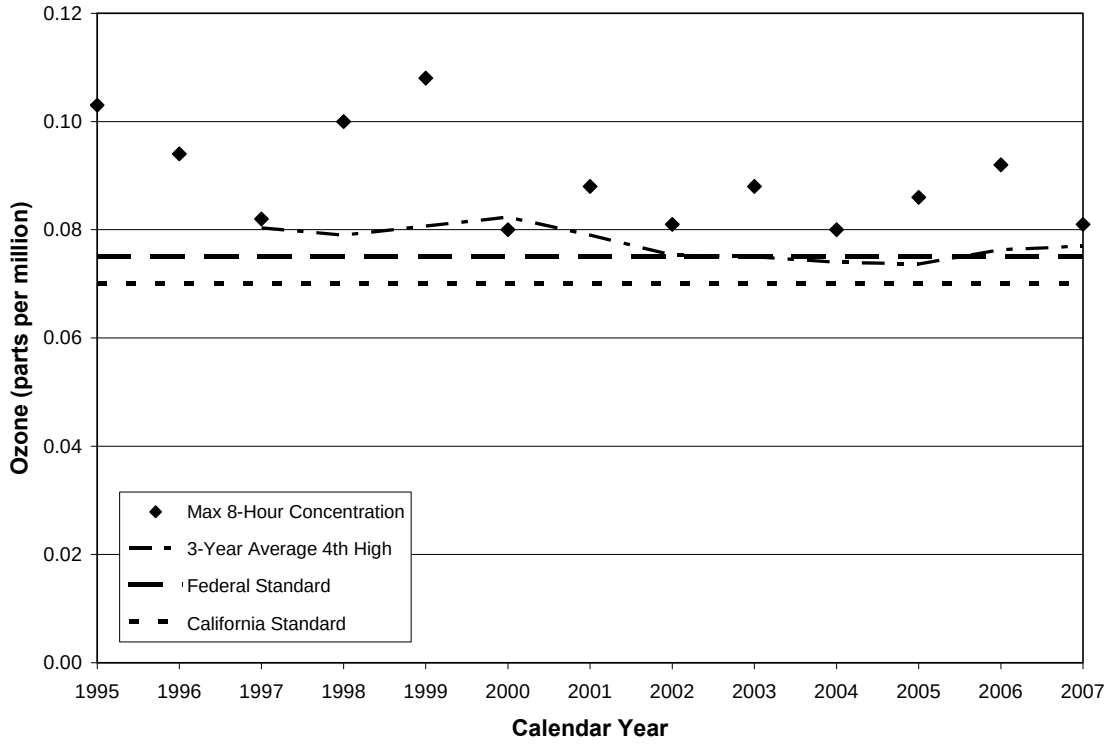


FIGURE 5.1-3
Maximum 8-hour Ozone Level: Stockton-Hazelton: 1995-2007

5.1.1.3.4 Nitrogen Dioxide

Atmospheric NO_2 is formed primarily from reactions between nitric oxide (NO) and oxygen or ozone. NO is formed during high temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is much less harmful than NO_2, it can be converted to NO_2 in the atmosphere within a matter of hours, or even minutes, under certain conditions. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is in attainment for NO_2.

Table 5.1-4 shows the annual maximum one-hour NO_2 levels recorded at the Stockton-Hazelton monitoring station in Stockton from 1998 through 2007, as well as the annual average level for each of those years. During this period, there have been no violations of either the state 1-hour standard (0.18 ppm) or the federal annual average standard (0.053 ppm). Figure 5.1-4 shows the trend from 1995 through 2007 of maximum 1-hour NO_2 levels at Stockton. These levels have been well below the state standard for many years.

TABLE 5.1-4
Nitrogen Dioxide Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-hour Average	0.102	0.106	0.099	0.084	0.076	0.088	0.079	0.087	0.072	0.070
Annual Average	0.023	0.024	0.021	0.019	0.021	0.018	0.017	0.017	0.018	0.016
Number of Exceeding:										
State Standard (days) (0.18 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard (years) (0.053 ppm, annual)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board, and AIRData, EPA

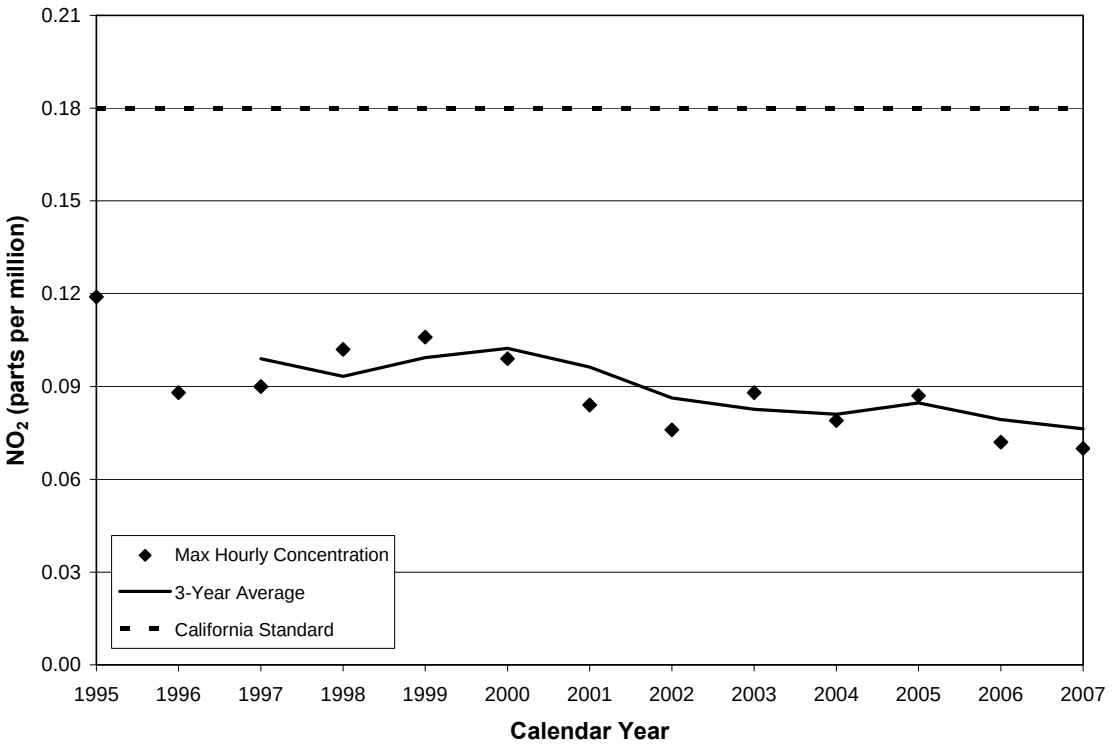


FIGURE 5.1-4
Maximum 1-hour NO_2 Level: Stockton-Hazelton: 1995-2007

5.1.1.3.5 Carbon Monoxide

CO is a product of incomplete combustion, principally from automobiles and other mobile sources of pollution. In many areas of California, CO emissions from wood-burning stoves and fireplaces can also be measurable contributors to high ambient levels of CO. Industrial sources typically contribute less than 10 percent of ambient CO levels. Peak CO levels occur typically during winter months, due to a combination of higher emission rates and stagnant weather conditions. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is classified as being in attainment for CO.

Table 5.1-5 shows the California and federal air quality standards for CO, and the maximum 1-hour and 8-hour average levels recorded at the Stockton-Hazelton monitoring station in Stockton during the period 1998–2007.

Trends of maximum 8-hour and 1-hour average CO, shown in Figures 5.1-5 and 5.1-6, respectively, demonstrate that maximum ambient CO levels at Stockton have been below the state and federal standards since 1995.

TABLE 5.1-5
Carbon Monoxide Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 8-hour average	7.2	5.3	3.9	6.0	3.2	3.1	2.5	2.9	2.3	2.3
Highest 1-hour average	8.9	8.3	6.5	8.4	6.0	5.8	3.7	4.3	4.4	3.6
Number of days exceeding:										
State Standard (20 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
State Standard (9.0 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (35 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (9 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board, and AIRData, EPA

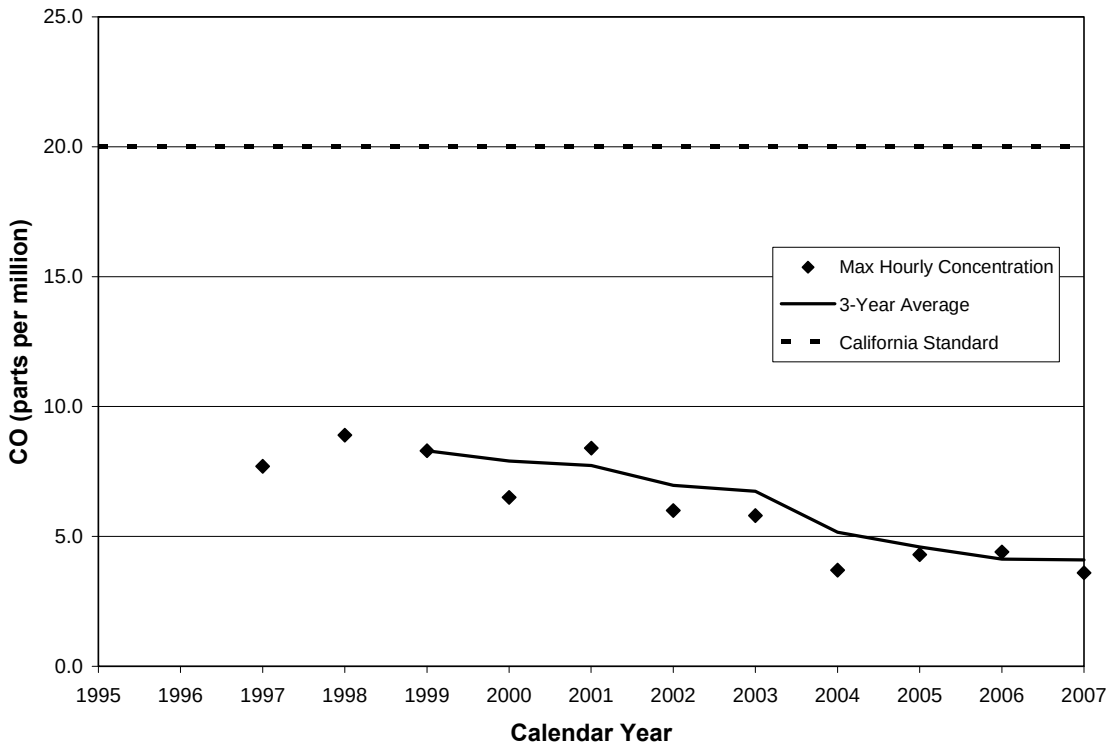


FIGURE 5.1-5
Maximum 1-hour Average CO Level: Stockton-Hazelton: 1997-2007

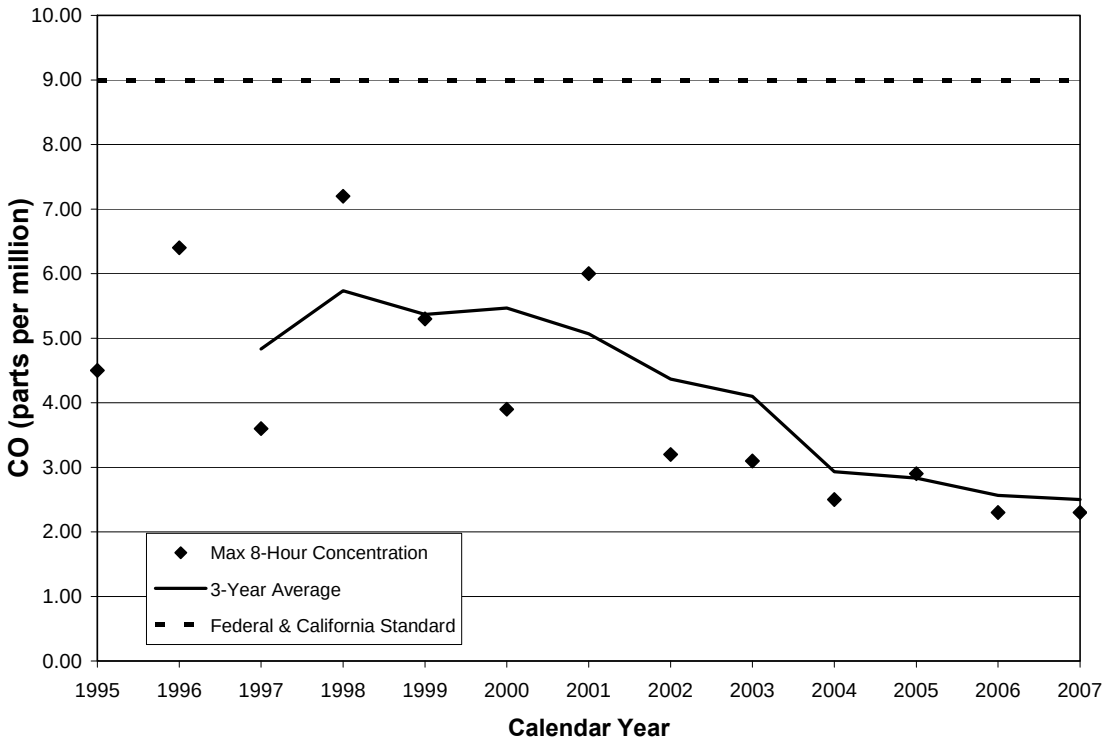


FIGURE 5.1-6
Maximum 8-hour Average CO Level: Stockton-Hazelton: 1995-2007

5.1.1.3.6 Sulfur Dioxide

SO_2 is produced when any sulfur-containing fuel is burned. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains negligible sulfur, while fuel oils contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. The San Joaquin Valley Air Basin is considered to be in attainment for SO_2 for purposes of state and federal air quality planning.

Table 5.1-6 presents the state and federal air quality standards for SO_2 and the maximum levels recorded at Bethel Island Road (the nearest SO_2 monitoring station) from 1998 through 2007. Maximum 1-hour average and 24-hour average readings have been an order of magnitude below the state standard. The federal annual average standard is 0.03 ppm; during most of the period shown, annual average SO_2 levels at this site have been less than one-tenth of the federal standard. Figure 5.1-7 shows that for several years the maximum SO_2 levels generally have been less than one-fourth of the state standard.

TABLE 5.1-6
Sulfur Dioxide Levels at Bethel Island, 1998–2007 (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-Hour Average	0.028	0.029	0.018	0.015	0.029	0.016	0.015	0.017	0.017	0.018
Highest 24-hour Average	0.009	0.008	0.007	0.007	0.009	0.006	0.006	0.006	0.007	0.005
Annual Average	0.002	0.002	0.002	0.002	0.003	0.002	0.002	0.002	0.002	0.002
Number of Exceedances:										
Federal Standard										
(0.14 ppm, 24-hour) (days)	0	0	0	0	0	0	0	0	0	0
(0.03 ppm, annual) (years)	0	0	0	0	0	0	0	0	0	0

Source: AIRData, EPA

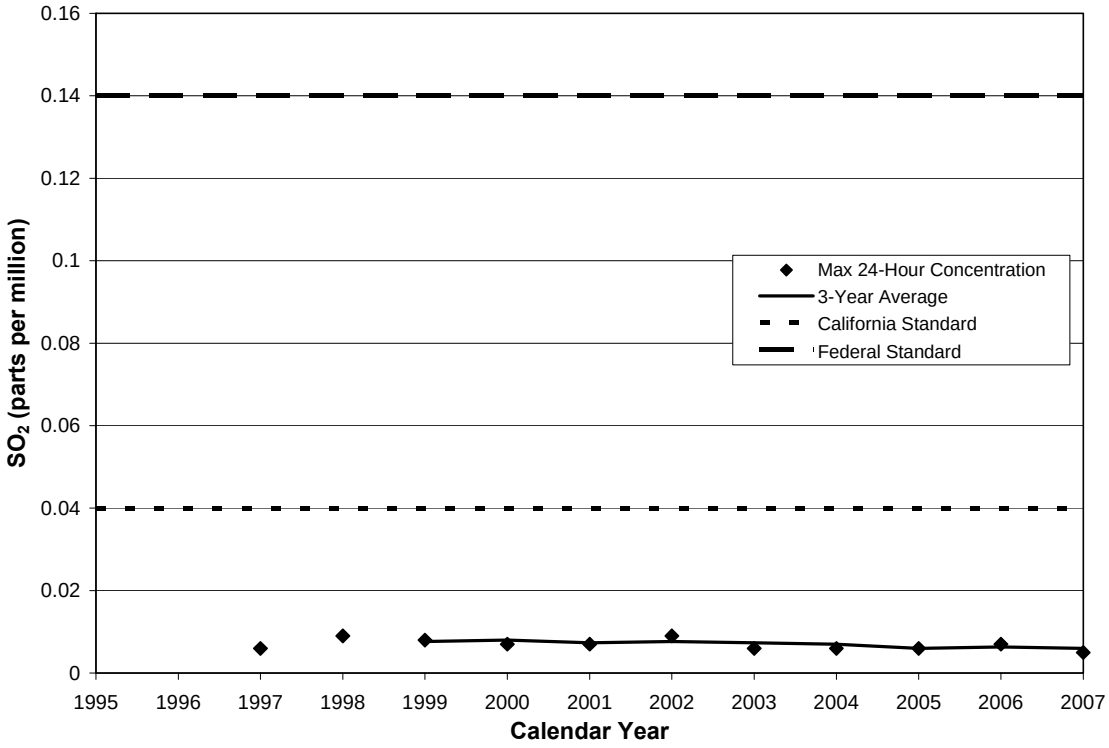


FIGURE 5.1-7
Maximum 24-hour Average SO2 Level: Bethel Island Road: 1997-2007

5.1.1.3.7 Particulate Sulfates

Particulate sulfates are the product of further oxidation of SO_2. The San Joaquin Valley Air Basin is in attainment of the state standard for sulfates (24-hour average < 25µg/m^3). There is no federal standard for sulfates.

Due to extremely low ambient levels, sulfates have not been monitored in San Joaquin County at least since 1990. Table 5.1-7 presents maximum 24-hour average sulfate levels recorded in Bakersfield, the monitoring station closest to the project site, for the period 1995-2002, after which sulfate monitoring ceased at that station. During the period 1995-2002, sulfate levels in Bakersfield have been only about 17 percent of the state standard.

TABLE 5.1-7
Particulate Sulfate Levels in Bakersfield, 1995–2002 (micrograms per cubic meter)

	1995	1996	1997	1998	1999	2000	2001	2002
Highest 24-hour Average	4.3	3.5	3.5	3.5	3.7	3.7	3.6	3.9
Number of Days Exceeding State Standard (25 µg/m3, 24-hour)	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

5.1.1.3.8 Fine Particulates (PM_{10} and $PM_{2.5}$)

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources (usually carbon particles); and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides. In 1984, the CARB adopted standards for fine particulates (PM_{10}), and phased out the total suspended particulate (TSP) standards that had previously been in effect. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of inhalable particulates related to human health. In 1987, EPA also replaced national TSP standards with PM_{10} standards. For air quality planning purposes, the San Joaquin Valley Air Basin is considered to be in nonattainment of both federal and state PM_{10} standards.

Table 5.1-8 shows the federal and state air quality standards for PM_{10}, maximum levels, and arithmetic annual averages recorded at Stockton-Hazelton in Stockton from 1998 through 2007. Maximum 24-hour PM_{10} levels from this site frequently exceed the state standards, but have not exceeded the federal standard. Annual average PM_{10} levels are above the state standard during the monitoring period.

The trend of maximum 24-hour average PM_{10} levels is plotted in Figure 5.1-8, and the trend of estimated violations of the state 24-hour standard of 50 µg/m3 is plotted in Figure 5.1-9. Note that since PM_{10} is generally measured only once every six days, expected violation days are usually about six times the number of measured violations. The trends of maximum annual average PM_{10} readings and the California standard are shown in Figure 5.1-10. Annual average PM_{10} concentrations are above the state standard of 20 µg/m^3.

TABLE 5.1-8
PM_{10} Levels at Stockton-Hazelton, Stockton, 1998-2007 (µg/m^3)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 24-hour Average										
State	115	155	97	147	91	90	61	84	85	75
Federal	106	150	91	140	87	88	60	79	82	71
Annual Arithmetic Mean (State Standard = 20 µg /m^3)	30.1	37.7	33.7	36.6	36.1	28.4	29.4	29.8	33.4	27.7
Expected Number of Days Exceeding:										
State Standard (50 µg/m^3, 24-hour)	49.8	67.2	52.1	64.1	58.4	17.3	18.0	46.5	62.9	23.5
Federal Standard (150 µg/m^3, 24-hour)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

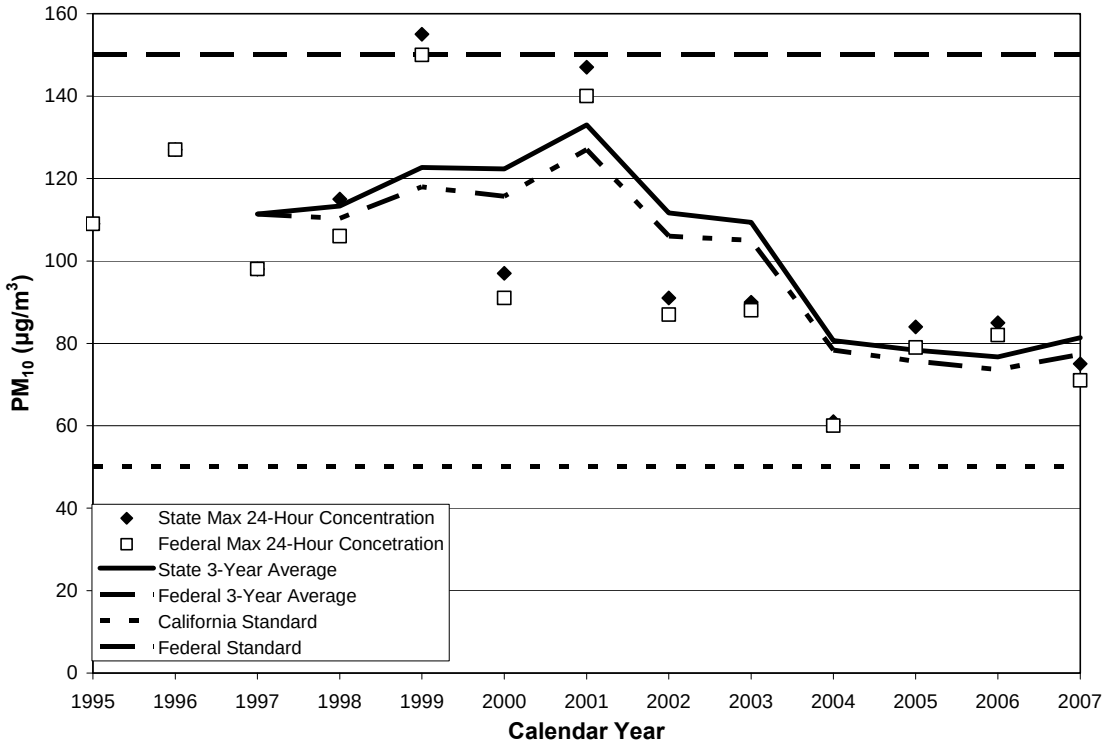


FIGURE 5.1-8
Maximum 24-hour Average PM_{10} Level: Stockton-Hazelton: 1995-2007

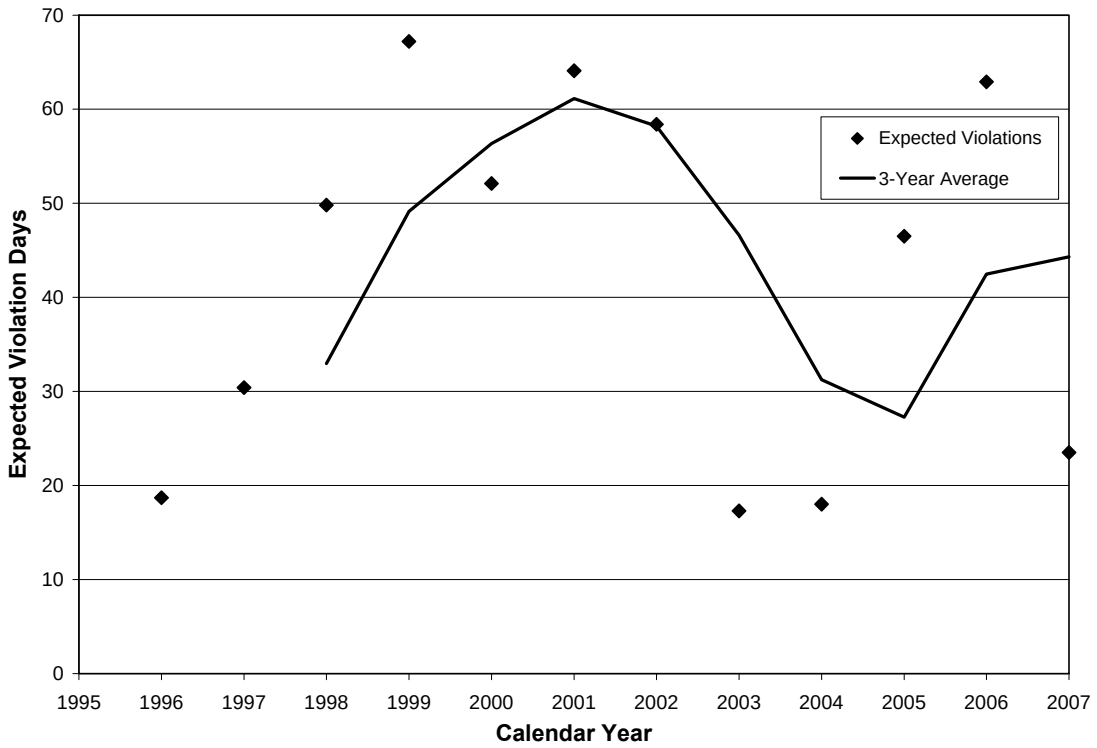


FIGURE 5.1-9
Expected Violations of the California 24-hour PM_{10} Standard: Stockton-Hazelton: 1995-2007

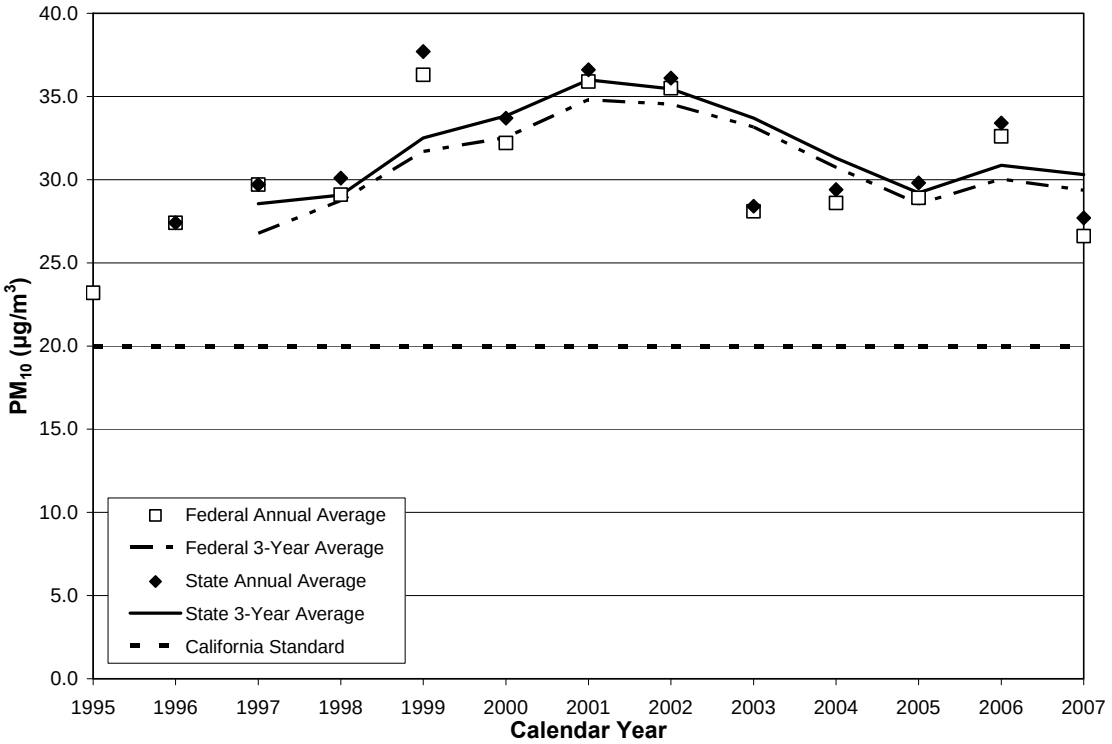


FIGURE 5.1-10
Annual Average PM_{10} Level: Stockton-Hazelton: 1995-2007

$PM_{2.5}$ is also measured at the Stockton-Hazelton monitoring station. Maximum 24-hour average readings have met EPA's federal standard (35 µg/m^3) that is applied to the 3-year average 98th percentile reading, since 2002.

Table 5.1-9 shows the federal air quality standards for $PM_{2.5}$, maximum levels recorded at the Stockton-Hazelton monitoring station in Stockton during 1998-2007, and 3-year averages for the same period. Annual average $PM_{2.5}$ levels have exceeded the state standard during monitoring years, but have been below the federal standard since 2003. As for PM_{10}, $PM_{2.5}$ is measured only once every 6 days, so expected exceedances are 6 times the number of measured exceedances. The San Joaquin Valley Air Basin is considered a nonattainment area for the state $PM_{2.5}$ standard but the attainment status for the federal $PM_{2.5}$ standard has not yet been determined.

The trend of federal annual average $PM_{2.5}$ levels is plotted in Figure 5.1-11, and the trend of maximum 24-hour average levels is plotted in Figure 5.1-12.

TABLE 5.1-9
$PM_{2.5}$ Levels Stockton-Hazelton, Stockton, 1998-2007 (µg/m^3)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 24-hour Average	*	101	78	76	64	45	41	63	47	52
Number of Days Exceeding:										
Federal Standard (35 µg/m^3, 24-hour)	*	15.3	3	5.9	0	0	0	0	0	0
98th Percentile	*	79	55	58	50	41	36	44	42	48
3-yr Average, 98th Percentile	*	*	*	64	54	50	42	40	41	45
Annual Arithmetic Mean	*	19.7	15.5	13.9	16.7	13.6	13.2	12.5	13.1	12.9
3-yr Annual Average	*	*	*	16.4	15.3	14.7	14.5	13.1	12.9	12.8
(Federal Std = 15 µg/m^3)										

Source: California Air Quality Data, Annual Summary, California Air Resources Board

*There were insufficient (or no) data available to determine the value.

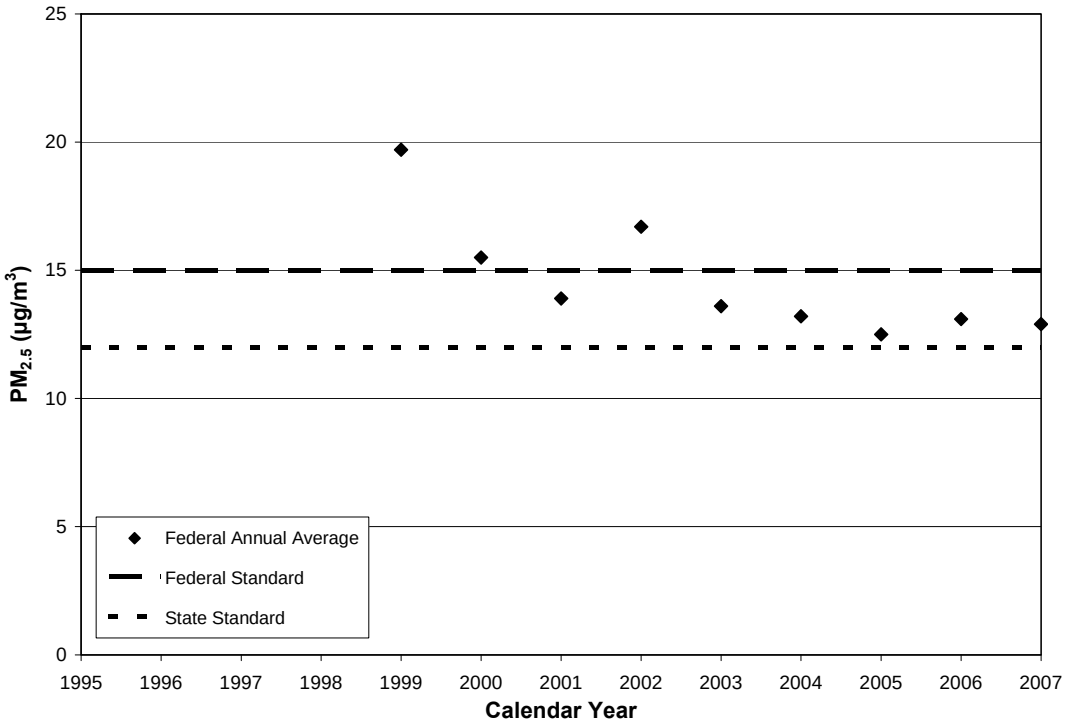


FIGURE 5.1-11
Federal Annual Average $PM_{2.5}$ Level: Stockton-Hazelton: 1999-2007

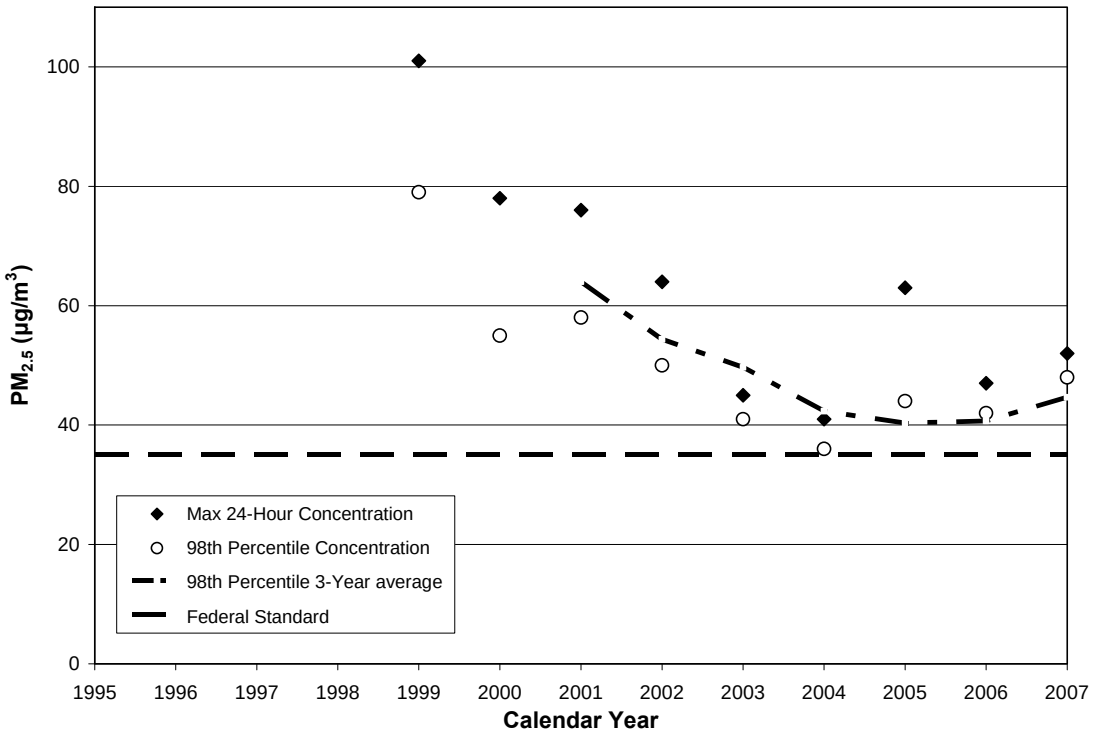


FIGURE 5.1-12
Maximum 24-Hour $PM_{2.5}$ Level: Stockton-Hazelton: 1999-2007

5.1.1.3.9 Airborne Lead

The majority of lead in the air results from the combustion of fuels that contain lead. Until 30 years ago, motor gasolines contained relatively large amounts of lead compounds used as octane-rating improvers, with the result that ambient lead levels were relatively high. Beginning with the 1975 model year, however, manufacturers began to equip new automobiles with exhaust catalysts, which are poisoned by the exhaust products of leaded gasoline. Thus, unleaded gasoline became the required fuel for an increasing fraction of new vehicles, and the phase out of leaded gasoline began. As a result, ambient lead levels decreased dramatically, and for several years California air basins, including the San Joaquin Valley Air Basin, have been in attainment of state and federal airborne lead standards for air quality planning purposes. Table 5.1-10 lists the state air quality standard for airborne lead and the levels recorded in the Stockton-Hazelton station between 1998 and 2003. Table 5.1-10 indicates that airborne lead levels have been well below the ambient air quality standard of 1.5 $\mu g/m^3$ for the period 1998 through 2003.

TABLE 5.1-10
Airborne Lead at Stockton-Hazelton, Stockton, 1998-2003($\mu g/m^3$)

	1998	1999	2000	2001	2002	2003
Highest Daily Average	0.02	0.02	0.03	0.02	0.02	0.02
Number of Day Exceeding Federal Standard (1.5 $\mu g/m^3$)	0	0	0	0	0	0

Source: AIRData, EPA

5.1.2 Project Description

5.1.2.1 Current Facility

The equipment at the existing NCPA STIG plant consists of one 49 MW GE LM-5000 natural gas-fired, steam-injected (STIG) combustion gas turbine and one 240 HP Cummins diesel fire pump engine. There is also a small cooling tower at the facility, which is exempt from permitting under the SJVAPCD rules because its circulation rate is less than 10,000 gallons per minute (Rule 2020, Section 6.2). The only change to be made to the existing facility is the relocation of the exempt cooling tower.

5.1.2.2 Proposed Facility

The proposed combined-cycle unit will consist of a General Electric PG7241FA combustion turbine, a heat recovery steam generator with duct firing, and a 95 MW (nominal) condensing steam turbine, for a total nominal plant output of 255 MW. The CTG will use "Rapid Response" technology. The Rapid Response package, which includes a modified HRSG design and an auxiliary boiler, is designed to allow earlier startup of the steam turbine by decoupling the gas turbine from the HRSG, thereby reducing startup emissions. The project will also include a cooling tower.

The combustion turbine, duct burners and auxiliary boiler will be fueled exclusively with natural gas. The combustion turbine will be equipped with an inlet air evaporative cooling system to maintain turbine output across the full range of ambient temperatures. Based on operation at an ambient temperature of 61.2°F, with evaporative cooling of the CTG inlet air to 55.8°F and without duct firing, the facility will have a heat rate of approximately

6,797 Btu/kWh (HHV). The facility will have an incremental heat rate with duct firing of approximately 8,773 Btu/kWh (HHV).

Post-combustion air pollution controls for the gas turbine/HRSG will include SCR for NO_x control and an oxidation catalyst for CO control. The turbine and HRSG may be operated up to 24 hours per day, 7 days per week. LEC will be frequently dispatched and will operate on the order of approximately a 76 to 82 percent annual capacity factor.

The auxiliary boiler is expected to operate only during turbine startups. Specifications for the new combustion turbine and HRSG are summarized in Table 5.1-11; auxiliary boiler specifications are provided in Table 5.1-12. A typical fuel analysis is summarized in Table 5.1-13.

TABLE 5.1-11
New GE 7FA Combustion Turbine/HRSG Design Specifications

Gas Turbine Manufacturer:	General Electric
Gas Turbine Model:	PG7241FA
Fuel:	Natural gas
Design Ambient Temperature*:	23.7°F
Nominal Heat Input Rate:	1885 MMBtu/hr @ HHV (gas turbine only) 2107 MMBtu/hr @ HHV (gas turbine with duct firing)
Gas Turbine Nominal Power Generation Rate:	180 MW
Plant Nominal Net Power Output:	255 MW
Nominal Exhaust Temperature:	180 °F
Exhaust Flow Rate (nominal, base load):	991,425 acfm
Exhaust O_2 Concentration, dry volume:	13.7%
Exhaust CO_2 Concentration, dry volume:	4.1%
Exhaust Moisture Content, wet volume:	8.8%
Emission Controls:	Dry Low-NO_x burners and SCR (2.0 ppmv NO_x @ 15% O_2) Oxidation catalyst (3.0 ppmv CO @ 15% O_2)

*Low-temperature scenario.

TABLE 5.1-12
New Auxiliary Boiler Design Specifications

Boiler Manufacturer:	Rentech Boiler Systems, Inc
Boiler Model:	“D” type, model TBA
Fuel:	Natural gas
Nominal Heat Input Rate:	65 MMBtu/hr @ HHV
Nominal Steam Generation Rate:	45,000 lb/hr
Emission Controls:	Low-NO_x burner (7.0 ppmv NO_x @ 3% O_2)

TABLE 5.1-13
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	**Average Concentration, Volume**	**Constituent**	**Percent by Weight**
CH_4	94.61%	C	71.42 %
C_2H_6	2.07%	H	23.47 %
C_3H_8	0.19%	N	3.75 %
C_4H_{10}	0.08%	O	1.36 %
C_5H_{12}	0.02%	S	1 gr/100 scf
N_2	2.27%	Higher Heating Value	1004 Btu/scf 22,524 Btu/lb
CO_2	0.65%		
S	<0.00%		

5.1.3 Emissions Evaluation

5.1.3.1 Current Facility Emissions and Permit Limitations

The existing facility potential to emit (PTE) is summarized in Table 5.1-14. Daily emissions from the existing combustion turbine are limited by permit, so annual PTE is calculated assuming maximum daily operation for 8760 days per year. Emissions from the emergency fire pump engine are calculated based on 50 hours per year limitation on testing and maintenance operations in the applicable CARB Air Toxic Control Measure.[3] Because the existing cooling tower is exempt from permitting, its emissions are assumed to be insignificant and are not included.

TABLE 5.1-14
Potential to Emit for Existing NCPA Lodi Equipment

	Emissions, tons per year*				
Unit	**NO_x**	**SO_2**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**
LM5000 STIG	20.4	5.7	58.8	25.9	8.8
Emergency Diesel Fire Pump Engine	0.08	<0.01	0.04	0.01	0.01

*Detailed calculations provided in Appendix 5.1A, Tables 5.1A-1 and 5.1A-2.

5.1.3.2 Facility Operations

5.1.3.2.1 New 7FA Combustion Turbine with Duct Firing

Project designers evaluated combustion turbine performance under five temperature scenarios—extreme maximum temperature (107.7°F), typical summer temperature (94°F), annual average temperature (61.2°F), typical winter temperature (32.6°F), and extreme minimum temperature (23.7°F). The extreme minimum temperature scenario with duct firing was used to characterize maximum emissions because it has the highest hourly heat input

[3] Air Toxics Control Measure for Stationary Compression Ignition Engines, Title 17 CCR 93115 et seq.

and emission rates. Maximum NO_x, CO, and VOC emissions for each quarter are based on expected operations, including startups and duct firing, which are characteristic of the quarter. Maximum SO_2 and $PM_{10}/PM_{2.5}$[4] emissions are based on full-time operations, including duct firing. The quarterly operating profiles summarized in Table 5.1-15 below were used as the basis for the calculation of quarterly and annual emissions. These calculations are shown in more detail in Appendix 5.1A, Table 5.1A-6.

TABLE 5.1-15
Quarterly and Annual Operations for the CTG and HRSG

	Hot Start Hours	Cold Start Hours	Duct Firing Hours	Base Load Hours	Total Heat Input, MMBtu (HHV)
Q1	100	42	350	1,184	4,149,888
Q2	100	42	350	1,208	4,195,135
Q3	40	36	1100	800	4,406,844
Q4	72	36	700	1,040	4,318,064
Annual	312	156	2,500	4,232	17,069,130

5.1.3.2.2 New Auxiliary Boiler

The auxiliary steam boiler will provide steam during plant start-up and shut-down to allow startups and shutdowns to be accomplished more quickly. During pre-start activities and during the initial phases of start-up, steam for sealing, warming the steam turbine (optional), heating/re-heating condensate (condenser sparging steam), and combustion turbine fuel gas heating will be supplied from the auxiliary boiler. Because the auxiliary boiler will be used mainly to support turbine startup activities, quarterly and annual boiler emissions are calculated based on projected turbine startup hours. The quarterly operating profile assumed for the auxiliary boiler is shown in Table 5.1-16. NCPA proposes that the daily and quarterly operating limitations on auxiliary boiler operation be expressed in terms of heat input rather than hours of operation.

TABLE 5.1-16
Daily, Quarterly and Annual Operations for the Auxiliary Boiler

	Total Hours	Proposed Fuel Use Limitation for Period (MMBtu HHV)
Daily	12*	780
Q1	142	9,230
Q2	142	9,230
Q3	76	4,940
Q4	108	7,020
Annual	468	30,420

*Although the auxiliary boiler is expected to operate only during CTG startup, maximum daily emissions from the unit are evaluated assuming up to 12 hours per day of operation to provide maximum operational flexibility.

[4] All combustion PM is assumed to be less than 2.5 microns in diameter; therefore all PM_{10} is assumed to be $PM_{2.5}$.

5.1.3.2.3 New Cooling Tower

The cooling tower circulates cooling water and is used to condense steam discharging from the steam turbine. For this application, the cooling tower is assumed to operate 24 hours per day, 8,760 hours per year.

5.1.3.3 Normal Operations

The operating profiles described in Section 5.1.3.2 were used to develop daily, quarterly, and annual heat input limits for the fuel-burning equipment. These heat input limits, summarized in Table 5.1-17, were used as the basis for calculating project and facility emissions.

TABLE 5.1-17
Hourly, Daily and Annual Heat Input for the New Combustion Units

	Heat Input, MMBtu (HHV)	
Interval	**CTG with duct firing**	**Aux. Boiler**
Hourly	2,107.2	65
Daily	47,910	780
Annual	17,096,930	30,420

5.1.3.4 Criteria Pollutant Emissions

Criteria pollutants emitted from the fuel-burning equipment include NO_x, SO_2, CO, VOC, and fine particulate matter (PM_{10}).[5] The cooling tower will emit small quantities of PM_{10}. This section of the application presents calculated emissions from the new equipment.

The new equipment also will emit trace levels of toxic air contaminants (TACs), including ammonia. TAC emissions from the proposed new units are discussed in Section 5.1.3.5. Tables containing the detailed TAC emission calculations are included in Appendix 5.1A.

5.1.3.4.1 Criteria Pollutant Emissions: Combustion Turbine and HRSG

Proposed maximum emissions from the project were estimated on an hourly, daily, quarterly and annual basis based on expected daily operation and proposed quarterly and annual operating limitations.

Emissions During Normal Operations

Turbine and HRSG performance data are provided in Appendix 5.1A, Table 5.1A-3. Emissions of NO_x, CO, and VOC were calculated from emission limits (in ppmv @ 15 percent O_2) and the exhaust flow rates. The NO_x emission limit reflects the application of SCR. The VOC emission limit reflects the use of good combustion practices. The CO emission limit reflects the expected performance of the oxidation catalyst. Maximum emissions were based on the exhaust rates associated with the heat input rates shown in Table 5.1-17.

5 All of the particulate matter emitted from the fuel burning equipment and the cooling tower is assumed to be less than 2.5 microns in diameter. All references to PM_{10} include $PM_{2.5}$ as well.

SO_2 emissions were calculated from the heat input (in MMBtu) and an SO_2 emission factor (in lb/MMBtu). SO_2 emissions were calculated based on the maximum allowable fuel sulfur content of 1 grain per 100 standard cubic feet (scf) and the heat input rates in Table 5.1-17.

Maximum hourly PM_{10} emissions reflect expected turbine/HRSG performance, based on emissions limits from similar installations. $PM_{2.5}$ emissions were determined based on the assumption that all particulate matter emissions are less than 2.5 microns in size.

Maximum emission rates are summarized in Table 5.1-18. The BACT analysis upon which the emission factors are based is presented in Appendix 5.1C and summarized in Section 5.1.7.

TABLE 5.1-18
Maximum Emission Rates—Combustion Turbine/HRSG

Pollutant	ppmv @ 15% O_2	lb/MMBtu	lb/hr
Combustion Turbine without Duct Firing			
NO_x	2.0	0.0072	13.64
SO_2[b]	0.57	0.0028	5.37
CO	3.0	0.0066	12.46
VOC	1.4	0.0018	3.33
$PM_{10}/PM_{2.5}$[c]	--	--	9.0
Combustion Turbine with Duct Firing			
NO_x	2.0	0.0072	15.25
SO_2[d]	0.57	0.0028	6.00
CO	3.0	0.0066	13.93
VOC	2.0	0.0028	5.32
$PM_{10}/PM_{2.5}$[c]	--	--	11.0

[a]NO_x, CO, VOC, and PM_{10} emission rates exclude startups and shutdowns (see Table 5.1-19).

[b]Based on maximum natural gas sulfur content of 1 gr/100 scf. See text.

[c]Includes front and back half.

Emissions During Startup and Shutdown

Emissions of NO_x, CO, and VOC during turbine startup and shutdown will be higher than under normal operating conditions because the unit must operate at reduced loads while downstream components, including the HRSG, gas turbine and emissions control systems reach operating temperatures. As discussed in Section 2, NCPA is installing Rapid Response technology at LEC to minimize startup times; this technology is expected to significantly reduce startup times and, consequently, startup emissions. However, peak hourly emissions during startup will not necessarily be reduced. Further, since no Rapid Response configuration plants have yet been built or operated, no in-use operating data are yet available to allow observation and evaluation of the actual times required for a unit to come into compliance during a startup. Therefore, NCPA is conservatively assuming that the times required for startups of the LEC will be the same as those for conventional Frame 7-based combined cycle turbine plants.

The NO_x, CO, and VOC startup and shutdown emission rates used in calculating maximum hourly, daily, quarterly, and annual emissions from the LEC are shown in Table 5.1-19. SO_2 and PM_{10} emissions are not included in this table because emissions of these pollutants will not be higher during startup than during baseload facility operation.

Under cold start conditions, where the CTG has been shut down for more than 12 hours, it is assumed that the CTG will require 6 hours to come into compliance with permitted emission rates. Under hot start conditions, where the CTG has been shut down for less than 12 hours, it is assumed that the CTG can come into compliance in 2 hours.

TABLE 5.1-19
Maximum CTG Startup and Shutdown Emission Rates

	NO_x	CO	VOC
Startup, pounds per maximum hour	160	900	16
Startup, pounds per average hour	100	900	16
Shutdown, pounds per hour	100	900	16

5.1.3.4.2 Criteria Pollutants: Auxiliary Boiler

The emission rates for the auxiliary boiler shown in Table 5.1-20 are based on manufacturers' guaranteed emission rates and best available control technology requirements. The BACT determination is provided in Appendix 5.1C. Emission rates and calculated hourly emissions for this unit are shown in Appendix 5.1A, Table 5.1A-4.

TABLE 5.1-20
Maximum Emission Rates—Auxiliary Boiler

Pollutant	ppmv @ 3% O_2	lb/MMBtu	lb/hr
NO_x	7.0	0.0084	0.6
SO_2[a]	1.69	0.0028	0.2
CO	50	0.0365	2.4
VOC	10	0.0042	0.3
$PM_{10}/PM_{2.5}$[b]	--	--	0.5

[a]Based on maximum natural gas sulfur content of 1 gr/100 scf (see text).

[b]Includes front and back half.

5.1.3.4.3 Criteria Pollutants: Cooling Tower

The emission rates for the cooling tower are based on manufacturer's drift rate and the maximum cooling water TDS level. Emissions calculations for this unit are shown in Appendix 5.1A, Table 5.1A-5.

5.1.3.4.4 Criteria Pollutant Emissions Summary for the New Equipment

Maximum facility emissions are shown in Table 5.1-21. The emission calculations are based on the CTG/HRSG and auxiliary boiler emission rates shown in Tables 5.1-18 and 5.1-19; the fuel use limitations in Table 5.1-17; and the operating assumptions shown in Tables 5.1-15 and 5.1-16. Maximum daily operations are based on full-load operation of the turbine for 24 hours with 12 hours of duct firing for PM_{10} and SO_x, and with 6 hours of cold start,

18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC. These assumptions are used as the basis for the calculations and are not intended to be proposed as limits.

Detailed calculations, including quarterly emissions calculations, are shown in Appendix 5.1A, Table 5.1A-6.

TABLE 5.1-21
Criteria Pollutant Emissions from New Equipment

Emissions/Equipment	NO_x	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions[a]					
CTG/HRSG	160	6.0	900	16	11.0
Auxiliary Boiler	0.55	0.19	2.37	0.27	0.47
Cooling Tower	—	—	—	—	0.45
Total, pounds per hour	**160.5**	**6.2**	**902.4**	**16.3**	**11.9**
Maximum Daily Emissions[b]					
CTG/HRSG	864.9	136.4	5,641.9	179.8	240.0
Auxiliary Boiler	6.5	2.2	28.5	3.3	11.3
Cooling Tower	—	—	—	—	5.6
Total, pounds per day	**871.4**	**138.6**	**5,670.4**	**183.1**	**256.4**
Maximum Annual Emissions					
CTG/HRSG	71.3	24.3	254.4	17.4	41.9
Auxiliary Boiler	0.13	0.04	0.6	0.1	0.1
Cooling Tower	—	—	—	—	2.0
Total, tons per year	**71.5**	**24.3**	**254.9**	**17.5**	**44.0**

[a]Maximum hourly emissions include CTG in startup (for NO_x, CO and VOC), with auxiliary boiler and cooling tower in operation. Maximum hourly SO_2 and PM_{10} emissions from the CTG assume duct fired operation.

[b]Maximum daily emissions based on full-load turbine operation for 24 hours with 12 hours of duct firing for PM_{10} and SO_x; and 6 hours of cold start, 18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC.

5.1.3.5 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions from the project have been calculated using calculation methods and emission factors from the California Air Resources Board's December 5, 2007, regulatory update.[6] Calculations are based on the maximum proposed annual fuel use and corresponding generation. The calculations are shown in detail in Table 5.1A-7, Appendix 5.1A and the results are summarized in Table 5.1-22.

[6] California Air Resources Board, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," December 5, 2007 (Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007). http://www.arb.ca.gov/cc/ccei/reporting/GHGReportRegUpdate12_05_07.pdf.

TABLE 5.1-22
Greenhouse Gas Emissions from New Equipment

Unit	CO_2, metric tonnes/yr	CO_2. metric tonnes/MWh	CO_2eq, metric tonnes/yr[a]
CTG/HRSG	902,487	0.376	—
Auxiliary Boiler	1,608	Not applicable	–
Total	904,095	0.376	904,971

*Includes CH_4, N_2O and SF_6.

5.1.3.6 Hazardous Air Pollutants

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7] In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1). The SJVAPCD regulates toxic air contaminant emissions under the SJVAPCD's Integrated Air Toxic Program. This program integrates the state and federal requirements. Any pollutant that may be emitted from the LEC and is on the federal New Source Review list, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated as part of the AFC.

5.1.3.6.1 Toxic Air Contaminant Emissions: New Gas Turbine/HRSG and Auxiliary Boiler

Maximum hourly and annual TAC emissions were estimated for the gas turbine/HRSG and the auxiliary boiler based on the heat input rates (in MMBtu/hr and MMBtu/yr), emission factors (in lb/MMBtu), and the nominal fuel higher heating value of 1004 Btu/scf. Hourly and annual emissions were based on the heat input rates shown in Table 5.1-17. The ammonia emission factor was derived from an ammonia slip limit of 10 ppmv @ 15 percent O_2. At the request of the SJVAPCD [8], Ventura County emission factors were used to quantify other TAC emissions. The Ventura County AB2588 combustion emission factors do not include factors for hexane or propylene oxide or for speciated polyaromatic hydrocarbons (PAHs), so emission factors for these TACs were taken from the California Air Resources Board's CATEF database for natural gas-fired gas turbines. TAC emissions are summarized in Table 5.1-22. Detailed emissions calculations, including emission factors, are provided in Appendix 5.1A, Tables 5.1A-8 and 5.1A-9.

5.1.3.6.2 Toxic Air Contaminant Emissions: Cooling Tower

Maximum hourly and annual TAC emissions from the cooling tower are extremely low. As shown in Table 5.15-23, concentrations of most metals and salts in the water supply were below detection limits. Total TAC emissions from the cooling tower are shown in Appendix 5.1A, Table 5.1A-10.

7 These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

8 June 5, 2008, email message from Cheryl Lawler to Nancy Matthews, "District's Comments for Lodi Energy Center Modeling Protocol."

5.1.3.6.3 Toxic Air Contaminant Emissions: Existing Turbine

Maximum annual TAC emissions from the existing turbine have been calculated using the same emission factors as those used for the new turbine/HRSG. Detailed calculations are shown in Appendix 5.1A, Table 5.1A-11.

TABLE 5.1-23
Maximum Proposed TAC Emissions for the CTG/HRSG

Compound	Maximum Emissions, CTG/HRSG		Maximum Emissions, Aux Boiler	
	lb/hr	tpy	lb/hr	tpy
Ammonia[a]	28.2	114.3	0	0
Propylene	1.6	6.6	0.03	<0.01
Hazardous Air Pollutants				
Acetaldehyde	0.08	0.3	<0.01	<0.01
Acrolein	0.01	0.05	<0.01	<0.01
Benzene	0.03	0.1	<0.01	<0.01
1,3-Butadiene	0.001	0.004	<0.01	<0.01
Ethylbenzene	0.07	0.3	<0.01	<0.01
Formaldehyde	1.5	6.1	<0.01	<0.01
Hexane	0.5	2.2	<0.01	<0.01
Naphthalene	0.003	0.01	<0.01	<0.01
PAHs[b]	<0.001	0.003	<0.01	<0.01
Toluene	0.3	1.1	<0.01	<0.01
Xylene	0.1	0.6	<0.01	<0.01

[a]Based on 10 ppmc ammonia slip from CTG/HRSG SCR system. No ammonia use or emissions for auxiliary boiler.

[b]Excluding naphthalene. See Appendix 5.1A, Table 5.1A-8.

5.1.3.7 Total HAP Emissions After Modification

Total HAP emissions from the existing and new equipment are shown in Table 5.1-24 below. Note that ammonia and propylene are not HAPs and are not included in the calculation of total HAPs from the facility after modification.

TABLE 5.1-24
Total HAP Emissions from the Facility After Modification

Emissions Unit	Maximum Individual HAP Emissions, tons per year	Total HAP Emissions, tons per year
New LEC CTG/HRSG	6.1	11.1
New LEC Auxiliary Boiler	<0.01	<0.01
Existing STIG Turbine	1.4	2.6
Total	7.5	13.8

5.1.3.8 Construction

Emissions during the construction phase of the project have been estimated, including an assessment of emissions from vehicle and equipment exhaust and the fugitive dust generated from material handling. A detailed analysis of the emissions and ambient impacts is included in Appendix 5.1E. Construction emissions mitigation and/or control techniques proposed for use at the LEC site include but are not limited to the following:

- Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use of low-emitting gas and diesel engines meeting state and federal emissions standards for construction equipment, including, but not limited to, catalytic converter systems and Diesel particulate filter systems.

The following mitigation measures are proposed to control fugitive dust emissions during construction of the project:

- Use either water application or chemical dust suppressant application to control dust emissions from onsite unpaved road travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surfaces to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;
- Use wheel washers or wash off tires of all trucks exiting construction site; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

The LEC construction site impacts are not unusual in comparison to most construction sites. Construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards.

5.1.4 Best Available Control Technology Evaluation

5.1.4.1 Current Facility Control Technologies

The existing NCPA gas turbine is an aeroderivative LM5000 STIG unit that uses steam injection for NO_x control and power augmentation. The gas turbine also uses selective catalytic reduction (SCR) and an oxidation catalyst to achieve additional NO_x control and to control CO emissions, respectively. NO_x emissions are limited to 3.0 ppmvd and CO emissions are limited to 200 ppmvd, both corrected to 15% O_2 on a 3-hour rolling average basis.

5.1.4.2 Proposed Facility Best Available Control Technology

BACT is defined in 40 CFR 52.21(j) as:

"an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

The SJVAPCD defines BACT as the most stringent emission limitation or control technique that:

"Has been achieved in practice for such emissions unit and class of source; or

Is contained in any SIP approved by the EPA for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such limitation or control technique is not presently achievable; or

Is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as determined by the APCO."

A top-down BACT analysis is required for each pollutant that is subject to PSD review or that exceeds the SJVAPCD BACT thresholds. BACT applicability is discussed in Section 5.1.7.3. The required top-down BACT analysis is provided in Appendix 5.1C, and concludes that BACT for the proposed project is as shown in Table 5.1-25.

TABLE 5.1-25
BACT Determinations for LEC

Pollutant	Gas Turbine/HRSG	Auxiliary Boiler
NO_x	Dry low-NO_x combustor and selective catalytic reduction: 2.0 ppmc,[a] 1-hour average	Ultra-low NO_x burner: 7 ppmc[b]
CO	Oxidation catalyst: 3.0 ppmc, 3-hour average	Good combustion practices
VOC	1.4 ppmc, no duct firing 2.0 ppm, with duct firing 3-hour average	Good combustion practices
SO_2 and PM_{10}	Natural gas fuel and good combustion practices; inlet air filter; lube oil vent coalescer	Natural gas fuel and good combustion practices

[a]ppmc: parts per million by volume, dry. Gas Turbine/HRSG concentrations are corrected to 15% O_2.

[b]Boiler concentrations are corrected to 3% O_2.

5.1.5 Air Quality Impact Analysis

SJVAPCD Rule 2201 requires the Applicant to provide ambient air quality modeling analyses and other impact assessments. An ambient air quality impact assessment is also required by EPA for PSD review and by the CEC for CEQA review. These analyses are presented in this section. The air quality impact analyses have been prepared in accordance with modeling protocols submitted to and reviewed by the SJVAPCD and CEC staffs. The protocols and the comments provided are included in Appendix 5.1B.

5.1.5.1 Dispersion Modeling

An assessment of impacts from the LEC on ambient air quality has been conducted using EPA-approved air quality dispersion models. These models are based on various mathematical descriptions of atmospheric diffusion and dispersion processes in which a pollutant source impact can be calculated over a given area.

Figure 5.1B-1 in Appendix 5.1B shows the building layout used in the modeling analysis. Since the new equipment will operate alongside the existing plant, the modeling analysis included the existing STIG plant structures to account for any potential influences from those structures. The impact analysis was used to determine the worst-case ground-level impacts of the new equipment. The results were compared with established state and federal ambient air quality standards and PSD significance levels. If the standards are not exceeded then it is assumed that, in the operation of the facility, no exceedances are expected under any conditions. In accordance with the air quality impact analysis guidelines developed by EPA (40 CFR Part 51, Appendix W: Guideline on Air Quality Models) and CARB (Reference Document for California Statewide Modeling Guideline, April 1989), the ground-level impact analysis includes the following assessments:

- Impacts in simple, intermediate, and complex terrain;
- Aerodynamic effects (downwash) due to nearby building(s) and structures; and
- Impacts from inversion breakup (fumigation).

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that would limit the amount of final plume rise. Plume impaction on elevated

terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. Building downwash can occur when wind speeds are high and a building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee side (downwind) of the building or structure.

Fumigation conditions occur when the plume is emitted into a low-lying layer of stable air (inversion) that then becomes unstable, resulting in a rapid mixing of pollutants towards the ground. The low mixing height that results from this condition allows little diffusion of the stack plume before it is carried downwind to the ground. Although fumigation conditions rarely last as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in the summer.

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian distribution about the centerline of the plume. Concentrations at any location downwind of a point source such as a stack can be determined from the following equation:

$$C(x,y,z,H) = \left(\frac{Q}{2\pi\sigma_y\sigma_z u}\right) * \left(e^{-1/2(y/\sigma_y)^2}\right) * \left[\left\{e^{-1/2(z-H/\sigma_z)^2}\right\} + \left\{e^{-1/2(z+H/\sigma_z)^2}\right\}\right]$$

where

C = the concentration in the air of the substance or pollutant in question

Q = the pollutant emission rate

σ_y,σ_z = the horizontal and vertical dispersion coefficients, respectively, at downwind distance x

u = the wind speed at the height of the plume center

x,y,z = the variables that define the 3-dimensional Cartesian coordinate system used; the downwind, crosswind, and vertical distances from the base of the stack

H = the height of the plume above the stack base (the sum of the height of the stack and the vertical distance that the plume rises due to the momentum and/or buoyancy of the plume)

Gaussian dispersion models are approved by EPA for regulatory use and are based on conservative assumptions (i.e., the models tend to overpredict actual impacts by assuming steady-state conditions, no pollutant loss through conservation of mass, no chemical reactions, etc.). The EPA models were used to determine if ambient air quality standards would be exceeded, and whether a more accurate and sophisticated modeling procedure would be warranted to make the impact determination. The following sections describe:

- Screening modeling procedures
- Refined air quality impact analysis
- Existing ambient pollutant concentrations and preconstruction monitoring

- Results of the ambient air quality modeling analyses
- PSD increment consumption

5.1.5.2 Model Selection

The screening and refined air quality impact analyses were performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (current version 04300). The AERMOD model is a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground elevations can exceed the stack heights of the emission sources (i.e. complex terrain).[9] The model is capable of estimating concentrations for a wide range of averaging times (from 1 hour to 1 year).

Inputs required by the AERMOD model include the following:

- Model options
- Meteorological data
- Source data
- Receptor data

Model options refer to user selections that account for conditions specific to the area being modeled or to the emissions source that needs to be examined. Examples of model options include use of site-specific vertical profiles of wind speed and temperature; consideration of stack and building wake effects; and time-dependent exponential decay of pollutants. The model supplies recommended default options for the user for some of these parameters.

AERMOD uses hourly meteorological data to characterize plume dispersion. The representativeness of the data is dependent on the proximity of the meteorological monitoring site to the area under consideration, the complexity of the terrain, the exposure of the meteorological monitoring site, and the period of time during which the data are collected. The meteorological data used in this analysis were collected at the Woodley Island NWS.

5.1.5.3 Good Engineering Practice Stack Height Analysis

For the purposes of modeling, a stack height beyond what is required by Good Engineering Practices (GEP) is not allowed (40 CFR Part 60 §51.164). However, this requirement does not place a limit on the actual constructed height of a stack. GEP as used in modeling analyses is the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP stack height modeling restriction assures that any required regulatory control measure is not compromised by the effect of that portion of the stack that exceeds the GEP height. The EPA guidance ("Guideline for Determination of Good Engineering Practice Stack Height," Revised 6/85) for determining GEP stack height indicates that GEP is the lesser of 65 meters or H_g, where H_g is calculated as follows:

$$H_g = H + 1.5L$$

[9] AERMOD was adopted in November 2005 as a guideline model by EPA as a replacement for ISCST3. AERMOD incorporates an improved downwash algorithm as compared to ISCST3 (Federal Register, November 9, 2005; Volume 70, Number 216, Pages 68218-68261).

Where:

H_g = Good Engineering Practice stack height, measured from the ground-level elevation at the base of the stack

H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack

L = lesser dimension, height or maximum projected width, of nearby structure(s)

In using this equation, the guidance document indicates that both the height and width of the structure are determined from the frontal area of the structure, projected onto a plane perpendicular to the direction of the wind. For the LEC, the nearest influencing structure is the HRSG, which is 105 feet above ground level. Therefore, GEP stack height is 2.5 times that height, or 262.5 feet. The proposed stack height of 150 feet will not exceed GEP stack height, so the full physical stack height may be used in the modeling analysis.

For regulatory applications, a building is considered sufficiently close to a stack to cause wake effects when the downwind distance between the stack and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. Building dimensions for the buildings analyzed as downwash structures were obtained from plot plans. The building dimensions were analyzed using the Lakes Environmental Building Profile Input Program (BPIP) to calculate 36 wind-direction-specific building heights and projected building widths for use in building wake calculations. The building dimensions used in the GEP analysis are shown in Appendix 5.1B, Table 5.1B-1. As the existing power plant structures will remain in place, those structures are reflected in the downwash analysis.

5.1.5.4 Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from USGS Digital Elevation Model (DEM) data using the 7½-minute format (10- to 30-meter spacing between grid nodes). All coordinates were referenced to UTM North American Datum 1927 (NAD27), Zone 10. The AERMOD receptor elevations were interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option was chosen. Hills were not imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids were 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 impact locations. A 250-meter resolution coarse receptor grid was developed, which extend outwards at least 10 km from the location of the new turbine stack.

In addition, more refined nested grids were developed to efficiently identify the maximum impact areas. These nested grids had the following resolutions:

- 25-meter resolution along the facility fence line in a single tier of receptors composed of four segments extending out to 100 meters from the fence line;
- 100-meter resolution from 100 meters to 1,000 meters from the fence line; and

- 250-meter resolution from 1 km out to at least 10 km from the site.

When maximum impacts occurred in the 100- or 250-meter spaced areas, additional refined receptor grids with 25-meter resolution were placed around each maximum coarse grid impact and extended out to a distance of two coarse grid spacings from the coarse grid maxima in all directions from that point of impact. Concentrations within the facility fence line, representing property controlled by NCPA, were not calculated.

5.1.5.5 Meteorological Data Selection

SJVAPCD has prepared meteorological data sets applicable to most locations in the district and has processed them, using AERMET (Version 06341), into the format required by AERMOD. Hourly surface meteorological data (e.g., hourly wind speed and direction, temperature) for Stockton during the period 2000-2004 were obtained from the SJVAPCD's modeling website.[10,11] The Stockton monitoring station is located approximately 16 miles south-southeast of the project site. Upper air data from the Oakland International Airport monitoring station located approximately 56 miles southwest of the project site and approximately 60 miles west-southwest of the surface data station were used by SJVAPCD in creating the model-ready data set.

The surface characteristics appropriate to the land uses surrounding the meteorological station at Stockton (surface roughness length, albedo, and Bowen Ratio) were developed by SJVAPCD for the met station site following the guidance published by EPA in September 2005. Although this earlier guidance has been updated by EPA with the development of AERSURFACE (Version 08009) software (released on January 9, 2008), SJVAPCD staff believe that surface characteristics developed using AERSURFACE are not appropriate for use in the San Joaquin Valley. AERSURFACE obtains land use data from 1992 US Geological Survey National Land Cover Data. Because of the large amount of development in the valley since 1992, SJVAPCD staff believes that the land use data used by AERSURFACE is outdated. SJVAPCD staff has indicated that EPA staff has agreed that the older guidance can continue to be used for projects in the San Joaquin Valley.[12]

EPA requires the use of meteorological data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of onsite monitoring data are also outlined in the "*On-Site Meteorological Program Guidance for Regulatory Modeling Applications*" (1987b). The representativeness of the data depends on: (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected. District staff has determined that the Stockton meteorological data set

---

10 http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

11 In the June 5, 2008 comment letter, the SJVAPCD indicated that more than 10 percent of the meteorological data for year 2001 are missing, and that modeling results for that year should be used with caution. While all five years will be used in the modeling analyses, any modeling results based on 2001 met data will be flagged.

12 Villalvazo, Leland, personal communication with Eric Walther of Sierra Research, April 23, 2008.

is representative of conditions in the northern portion of San Joaquin County.[13] This area includes the project site. The SJVAB consists of a continuous intermountain valley approximately 250 miles long and averaging 80 miles wide. On the western edge of the Valley is the Coast Mountain range, with peaks reaching over 5,000 feet, and on the east side is the Sierra Nevada range with some peaks exceeding 14,000 feet. The Tehachapi Mountains form the southern boundary of the Valley. Terrain is open only at the northern end of the valley. Both the project site and the monitoring site are located near the northern end of the San Joaquin Valley, in the broad, flat center of the valley. There are no nearby large terrain features, such as hills or mountain ranges, to affect local wind flow patterns. Prevailing winds in the northern end of the valley are from the west through northwest on an annual basis, although there is a strong southeasterly component during the fall and winter months (see Appendix B for wind roses). Both the project site and the monitoring site are affected by the marine air that generally flows into the basin from the San Joaquin River Delta to the north. Based on these factors, we concur with SJVAPCD's conclusion that the wind direction and wind speed data collected at the Stockton meteorological monitoring stations are similar to the dispersion conditions at the project site and to the regional area. Thus, the Stockton meteorological data set satisfies the definition of representative data.

Representativeness has also been defined in the "*Workshop on the Representativeness of Meteorological Observations*" (Nappo et. al., 1982) as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application." Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Stockton meteorological monitoring station. Representativeness has additionally been defined in the PSD Monitoring Guideline (EPA, 1987a) as data that characterize the air quality for the general area in which the proposed project would be constructed and operated. As discussed above, because of the relative proximity of the Stockton meteorological data site to the proposed project site, the same large-scale topographic features that influence the meteorological data monitoring station also influence the proposed project site in the same manner.

5.1.5.6 Screening Modeling Analysis

To ensure the impacts analyzed were for maximum emission levels and worst-case dispersion conditions, a screening procedure was used to determine the inputs to the impact modeling for the new gas turbine. The screening procedure is used to identify the CTG/ HRSG operating conditions that would result in the maximum impacts on a pollutant-specific basis. The operating conditions examined in this screening analysis, along with their exhaust and emission characteristics, are shown in Appendix 5.1B, Table 5.1B-2. These operating conditions represent CTG operation at maximum, average, and minimum ambient operating temperatures (107.7°F, 61.2°F and 23.7°F), and at full load, peak load (with duct firing), and minimum load (50 percent).

Ambient impacts for each of the 9 operating cases were modeled using EPA's AERMOD model and 5 years of Stockton meteorological data, as described above. The results of the unit impact analysis are presented in Appendix 5.1B, Table 5.1B-3 and summarized in Table 5.1-26. The analysis showed that for short-term averaging periods, modeled impacts

[13] SJVAPCD, "Guidance for Dispersion Modeling," Working Draft, Rev 2.0, January 2007, p. 49. Available at http://www.valleyair.org/busind/pto/Tox_Resources/Modeling%20Guidance%20W_O%20Pic.pdf.

were highest under cold temperature, peak load operating conditions. For 24-hour averages, impacts were highest under cold temperature, low load operating conditions, while annual average impacts were highest under high temperature conditions.

TABLE 5.1-26
Results of Turbine Screening Procedure: Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period

Pollutants and Averaging Periods	Operating Case
NO_x, SO_2 and CO: 1-, 3- and 8-hour averages	Case 3
SO_2 and PM_{10}: 24-hour averages	Case 2
NO_x, SO_2 and PM_{10}: annual averages	Case 7

5.1.5.7 Refined Analysis

The screening modeling analysis described above was used to determine which CTG/HRSG operating parameters (emission rates and stack parameters) would be used in the subsequent refined analyses. The refined analyses are described in detail in the following sections.

5.1.5.7.1 Normal Operations Impact Analysis

The results of the AERMOD assessment for normal plant operations are summarized in Table 5.1-27 below. The following operating assumptions were used in developing the emission rates for each emissions unit and averaging period:

1-hour and 3-hour averages

- CTG/HRSG at peak load, cold temperature (maximum impact case from screening analysis)
- Auxiliary boiler in operation

8-hour average

- CTG/HRSG in startup for 6 hours and at peak load, cold temperature for two hours (maximum impact case from screening analysis)
- Auxiliary boiler in operation

24-hour averages

- CTG/HRSG at minimum load, cold temperature for 24 hours (maximum impact case from screening analysis)
- Auxiliary boiler in operation, maximum daily emission rates[14]
- Cooling tower in operation

[14] The auxiliary boiler is expected to operate only when the CTG is starting up or shutting down. However, to preserve maximum operational flexibility, the AQIA assumes that the auxiliary boiler may also operate during normal plant operation for up to 12 total hours per day.

Annual Averages

- CTG/HRSG at base load, hot temperature (maximum impact case from screening analysis), maximum annual emission rates
- Auxiliary boiler in operation, maximum annual emission rates
- Cooling tower in operation, maximum annual emission rate

Emission rates and stack parameters used in the refined modeling analysis are shown in Appendix 5.1B, Table 5.1B-4.

5.1.5.7.2 Startup and Shutdown Impacts Analysis

Short-term ambient impacts from the facility during turbine startup may be higher than impacts during normal operation because emission control systems are not fully operational during some part of the initial startup period when the turbine operates at low loads and the exhaust temperatures are low. Although the LEC gas turbine will use Rapid Response technology to minimize startup emissions, there are no in-use data available. Therefore, startup emissions and impacts were assessed using the very conservative assumption that there are no emissions or performance benefits from the Rapid Response technology. Turbine exhaust parameters for minimum load operation and under cold temperature conditions were used to characterize CTG exhaust during startup, because that operating case produced the highest modeled impacts in the screening analysis. CO and NO_x emission rates from Table 5.1-19 were used. Startup impacts were evaluated for the 1-hour averaging period; startup impacts are included in the modeling of 8-hour average CO impacts under normal operating conditions (above). The emission rates and stack parameters used are shown in Table 5.1B-5, Appendix 5.1B. The results of the analysis are summarized in Table 5.1-27.

5.1.5.7.3 Inversion Breakup Fumigation Modeling

Inversion breakup fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as 1 hour, relatively high ground-level concentrations may be reached during that time. For this analysis, fumigation was assumed to occur for up to 90 minutes, per EPA guidance.

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from EPA[15] was followed in evaluating fumigation impacts. The maximum fumigation impact from this analysis, which is shown in more detail in Appendix 5.1B, Table 5.1B-6, showed that impacts under fumigation conditions are expected to be lower than the maximum concentrations calculated by AERMOD under downwash conditions. Fumigation impacts for the turbine occurred between 10 km to 18 km from the facility, depending upon engine load (the AERMOD maximum 1-hour impact occurs about 1 km from the plant). Inversion breakup impacts are also shown in Table 5.1-27.

5.1.5.8 Total Facility Impacts

The maximum facility impacts calculated from the modeling analyses described above are summarized in Table 5.1-27. The highest modeled short-term impacts are expected to occur

[15] EPA-454/R-92-019, "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised."

under startup conditions. However, because the 1-hour average NO_2 impacts are driven by impacts from the auxiliary boiler, impacts under startup conditions are only marginally higher than impacts during normal turbine operation.

TABLE 5.1-27
Summary of Results from Refined Modeling Analysis for Permitted Sources

		Modeled Concentration (μg/m^3)		
Pollutant	**Averaging Time**	**Normal Operation**	**Inversion Breakup Fumigation[a]**	**Startup**
NO_2	1-hour[b]	27.5	2.9	31.8
	annual	0.3	--	--
SO_2	1-hour	10.4	1.1	--
	3-hours	7.6	1.0	--
	24-hours	2.9	0.5	--
	annual	0.1	--	--
CO	1-hour	132.9	2.7	323.8
	8-hours	110.5	1.9	--[c]
PM_{10}	24-hours	3.7[d]	0.9	--
	annual	0.9	--	--

[a]Inversion breakup is a short-term phenomenon and does not affect annual impacts.

[b]1-hour average NO_2 impacts were ozone-limited using PVMRM.

[c]Included in 8-hour impacts for normal operations.

[d]Highest impact for 2001 met data. Second highest concentration is 3.3 µg/m3 based on 2004 met data.

To determine a project's air quality impacts, the modeled concentrations are added to the highest reported background ambient air concentrations and then compared to the applicable ambient air quality standards. The highest reported background ambient concentrations were discussed in Section 5.1.1.3 and the monitored concentrations during the past 3 years are shown in the Table 5.1-28. More detailed discussions of why the data collected at these stations are representative of ambient concentrations in the vicinity of the project are provided in Sections 5.1.1.3.2 and 5.1.7.

TABLE 5.1-28
Highest Reported Background Concentrations in the Project Area

Pollutant	Averaging Period	2005	2006	2007
NO_2	1 hour	163.6	135.4	131.6
	annual	32.1	34.0	30.2
SO_2	1 hour	46.8	23.4	44.2
	3 hour	15.6	13.0	28.6
	24 hour	7.9	7.9	10.8
	annual	2.7	2.7	2.7
CO	1 hour	5,375	5,500	4,500
	8 hour	3,178	2,500	2,567

TABLE 5.1-28
Highest Reported Background Concentrations in the Project Area

Pollutant	Averaging Period	2005	2006	2007
PM_{10}	24 hour	84	85	75
	annual	29.4	33.4	27.7
$PM_{2.5}$	24 hour	44	42	48
	annual	12.5	13.1	12.9

Maximum ground-level impacts due to operation of the LEC are shown together with the ambient air quality standards in Table 5.1-29. The ambient air quality modeling results are extremely conservative and are designed to overpredict ambient concentrations because they evaluate impacts under a combination of worst-case conditions that are unlikely to occur simultaneously. The modeling combines the highest allowable emission rates with the most extreme meteorological conditions and the equipment operating load conditions that result in the highest ambient impact. Therefore it is extremely unlikely that the ambient concentrations predicted by the models will ever actually be realized. However, this analysis demonstrates that even under these combinations of conditions that overpredict impacts, the LEC will not cause or contribute to violations of any state or federal air quality standards, with the exception of the state PM_{10} and state and federal $PM_{2.5}$ standards. For this pollutant, existing concentrations already exceed the standards. However, the modeling results in Table 5.1-27 demonstrate that the project PM_{10} and $PM_{2.5}$ impacts will be below significant impacts levels of 5 µg/m^3 for the 24-hour averaging period and 1.0 µg/m^3 for the annual averaging period. Therefore, the proposed project will not contribute significantly to these exceedances.

TABLE 5.1-29
Modeled Maximum Impacts Plus Background

Pollutant	Averaging Time	Maximum Facility Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	State Standard (µg/m^3)	Federal Standard (µg/m^3)
NO_2	1-hour*	31.8	163.6	195.4	338	–
	Annual	0.3	34.0	34.3	–	100
SO_2	1-hour	10.4	46.8	57.2	650	–
	3-hour	7.6	28.6	36.2	–	1300
	24-hour	2.9	10.8	13.7	109	365
	Annual	0.1	2.7	2.8	–	80
CO	1-hour	324	5,500	5,824	23,000	40,000
	8-hour	111	3,178	3,289	10,000	10,000
PM_{10}	24-hour	3.7	85	88.7	50	150
	Annual	0.9	33.4	34.3	20	–
$PM_{2.5}$	24-Hour	3.7	48	51.7	–	35
	Annual	0.9	13.1	14.0	12	15

*Includes startup. Under normal operating conditions, total impact will be 27.5 µg/m^3.

5.1.5.9 Commissioning Impacts Analysis

The commissioning period begins when the CTG and HRSG are prepared for first fire and ends upon successful completion of initial performance testing. There are several high-emissions scenarios possible during commissioning. The first is the period prior to SCR system and oxidation catalyst installation, when the gas turbine combustion system is being tuned. Under this scenario, NO_x emissions would be high because the NO_x emissions control system would not be functioning and because the gas turbine would not be tuned for optimum performance. CO emissions would also be high because turbine performance would not be optimized and the CO emissions control system would not be functioning. The second high emissions scenario may occur when the gas turbine has been tuned but the SCR and oxidation catalyst installation is not complete. Since the control system installation would not be complete, NO_x and CO levels would again be high. Commissioning activities and expected emissions are shown in more detail in Table 5.1B-7, Appendix 5.1B.

The existing NCPA Lodi generating unit will be in operation during the commissioning of the LEC. An assessment of the air quality impacts of this combined operation have been included in the cumulative impacts analysis, provided in Appendix 5.1G.

Air quality impacts during the commissioning period were determined using the emission rates in Table 5.1B-7. One-hour average NO_2 impacts during commissioning were modeled using AERMOD_OLM and concurrent Stockton ozone data. Modeled impacts are shown in Table 5.1-30.

TABLE 5.1-30
Modeled Maximum Impacts During Commissioning of the CTG/HRSG

Pollutant	Averaging Time	Maximum Facility Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	State Standard ($\mu g/m^3$)	Federal Standard ($\mu g/m^3$)
NO_2	1-hour	36.4	163.6	200	338	–
CO	1-hour	718.2	5,500	6,218	23,000	40,000
	8-hour	535.0	3,178	3,713	10,000	10,000

5.1.6 Laws, Ordinances, Regulations, and Standards

The EPA has responsibility for enforcing, on a national basis, the requirements of many of the country's environmental and hazardous waste laws. California is under the jurisdiction of EPA Region 9, which has its offices in San Francisco. Region 9 is responsible for the local administration of EPA programs for California, Arizona, Nevada, Hawaii, and certain Pacific trust territories. EPA's activities relative to the California air pollution control program focus principally on reviewing California's submittals for the State Implementation Plan (SIP). The SIP is required by the federal Clean Air Act to demonstrate how all areas of the state will meet the national ambient air quality standards within the federally specified deadlines (42 USC §7409, 7411).

The CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. The CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update as necessary

the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards (California Health & Safety Code (H&SC) §39500 et seq.).

When the state's air pollution statutes were reorganized in the mid-1960s, local air pollution control districts (APCDs) were required to be established in each county of the state (H&SC §4000 et seq.). There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs), with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California (H&SC §40200 et seq.).

APCDs and AQMDs in California have principal responsibility for:

- Developing plans for meeting the state and federal ambient air quality standards;
- Developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution; and
- Enforcing air pollution statutes and regulations governing non-vehicular sources, and for developing employer-based trip reduction programs.

Each level of government has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project.

5.1.6.1 Federal LORS

The EPA implements and enforces the requirements of many of the federal environmental laws. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as the project. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the 1990 Clean Air Act:

- Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)
- Title IV: Acid Deposition Control
- Title V: Operating Permits

National Standards of Performance for New Stationary Sources

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60, Subpart KKKK

Purpose: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards) from new or modified facilities in specific source categories. The applicability of these regulations depends on the equipment size; process rate; and date of construction, modification, or reconstruction of the affected facility. The project is subject to the following NSPS:

Subpart KKKK, Standards of Performance for Stationary Gas Turbines (constructed after February 18, 2005) is applicable to the combined-cycle gas turbine and fired waste-heat recovery boiler; and

Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units), which applies to boilers that burn fossil fuel with a heat input capacity equal to or less than 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr, is applicable to the auxiliary boiler.

These standards are implemented at the local level with federal and state oversight.

Administering Agency: SJVAPCD, with EPA Region 9 and CARB oversight.

National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act § 112, 42 USC §7412; 40 CFR Part 63

Purpose: 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 source categories.[16] These standards are implemented at the local level with federal oversight. Only the NESHAP for combustion turbines, which limits formaldehyde emissions from turbines, is potentially applicable to the proposed project. However, as discussed further below, this NESHAP is not applicable to the proposed project because the facility would not be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs). Thus, NESHAPs requirements will not be addressed further.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Purpose: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, 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).

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. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tpy, or any other facility that emits at least 250 tpy.

The PSD program contains the following elements:

- Air quality monitoring
- BACT
- Air quality impact analysis

[16] A major source of HAPs is one that emits more than 10 tons per year (tpy) of any individual HAP, or more than 25 tpy of all HAPs combined.

- Protection of Class I areas
- Growth, visibility, soils, and vegetation impacts

Although the existing power plant is not a major stationary source, the proposed project itself will result in emissions exceeding the applicable PSD thresholds for NO_2 and CO[17] emitted from this source category[18] listed in the federal PSD regulations (40 CFR 52.21). Therefore, the proposed project is subject to PSD review. As the SJVAPCD does not have delegation for the PSD program, a separate PSD application is being filed with the EPA.

Air Quality Monitoring
At its discretion, EPA Region 9 may require pre-construction and/or post-construction ambient air quality monitoring for PSD sources if representative monitoring data are not already available. Pre-construction monitoring data must be gathered over a one-year period to characterize local ambient air quality. Post-construction air quality monitoring data must be collected as deemed necessary by EPA Region 9 to characterize the impacts of proposed project emissions on ambient air quality.

Best Available Control Technology
BACT must be applied to any new or modified major source to minimize the emissions increase of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant, considering energy, environmental, and economic impacts, that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP. BACT is defined below in the discussion of the SJVAPCD NSR regulatory requirements.

Air Quality Impact Analysis
An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. PSD source emissions must not cause an exceedance of any ambient air quality standard, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 5.1-31.

TABLE 5.1-31
PSD Class II Increments

Pollutant	Averaging Period	Allowable Increment ($\mu g/m^3$)
NO_2	Annual	25[a]
PM_{10}	Annual	17[a]
	24-Hour	30[b]
SO_2	Annual	20[a]
	24-Hour	91[b]
	3-Hour	512[b]

17 While EPA made a "determination of attainment" of the federal PM_{10} standard for the San Joaquin Valley Air Basin on October 30, 2006, the EPA has not yet "redesignated" the basin as attainment for PM_{10} (see 73 FR 22307; April 25, 2008). Therefore, PSD requirements are not applicable for PM_{10}.
18 Fossil fuel-fired steam-electric plant with heat input greater than 250 MMBtu/hour.

TABLE 5.1-31
PSD Class II Increments

Pollutant	Averaging Period	Allowable Increment ($\mu g/m^3$)

[a]Not to be exceeded

[b]Not to be exceeded more than once per year.

Protection of Class I Areas
The potential increase in ambient air quality concentrations for attainment pollutants (i.e., NO_2, PM_{10}, or SO_2) within Class I areas closer than approximately 100 km may need to be quantified if the new or modified PSD source were to have a sufficiently large emission increase as evaluated by the Class I area Federal Land Managers. In such a case, a Class I visibility impact analysis would also be performed.

Growth, Visibility, Soils, and Vegetation Impacts
Impairment to visibility, soils, and vegetation resulting from PSD source emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. This analysis includes cumulative impacts to local ambient air quality.

Administering Agency: EPA, Region 9.

Nonattainment New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Purpose: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient quality standards. In general, this program is implemented at the local level with EPA oversight. EPA recently promulgated new source review requirements for major sources of $PM_{2.5}$ for nonattainment areas that do not have federally approved SIPs, and EPA is responsible for implementing these requirements (see 73 FR 28231; May 16, 2008). Because the LEC is not a major source of $PM_{2.5}$ (i.e., the facility has a maximum potential to emit of less than 100 tons per year of $PM_{2.5}$), the facility is not subject to federal new source review requirements for $PM_{2.5}$.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Title IV – Acid Rain Program

Authority: Clean Air Act §401, 42 USC §7651 et seq.; 40 CFR Part 72

Purpose: Requires the monitoring and reporting of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to monitor, record, and, in some cases, limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Title V – Operating Permits Program

Authority: Clean Air Act § 501 (Title V), 42 USC §7661; 40 CFR Part 70

Purpose: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. These requirements are implemented at the local level with federal oversight.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

5.1.6.2 State LORS

The CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. The CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards. The CARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California H&SC:

- State Implementation Plan
- California Clean Air Act
- Toxic Air Contaminant Program
- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and CARB Memorandum of Understanding
- California Climate Change Regulatory Program

State Implementation Plan

Authority: H&SC §39500 et seq.

Purpose: Required by the federal Clean Air Act, the SIP must demonstrate the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines. The CARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules (and/or revise existing rules) and demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in the attainment of NAAQS. The relevant SJVAPCD Rules and Regulations that have also been incorporated into the SIP are discussed with the local LORS.

Administering Agency: SJVAPCD, with CARB and EPA Region 9 oversight.

California Clean Air Act

Authority: H&SC §40910 – 40930

Purpose: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained. The SJVAPCD Air Quality Plan is discussed with the local LORS.

Administering Agency: SJVAPCD, with CARB oversight.

Toxic Air Contaminant Program

Authority: H&SC §39650 – 39675

Purpose: Established in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants and control their emissions. The CARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants. The CARB also assesses the potential for human exposure to a substance, while the Office of Environmental Health Hazard Assessment (OEHHA) evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a toxic air contaminant. In 1993, the Legislature amended the program to identify the 187 federal hazardous air pollutants[19] as toxic air contaminants. The CARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions.

Nuisance Regulation

Authority: CA Health & Safety Code §41700

Purpose: Provides that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

Administering Agency: SJVAPCD and CARB

Air Toxic "Hot Spots" Act

Authority: CA Health & Safety Code § 44300-44384; 17 CCR §93300-93347

Purpose: Established in 1987, the Air Toxics "Hot Spots" Information and Assessment Act[20] supplements the toxic air contaminant program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: SJVAPCD, with CARB oversight.

CEC and CARB Memorandum of Understanding

Authority: CA Pub. Res. Code § 25523(a); 20 CCR §1752, 1752.5, 2300-2309, and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

---

[19] The EPA increased the original list of 188 HAPs to 189, and then removed Caprolactam (61FR30816, June 18, 1996) and methyl ethyl ketone on December 19, 2005, reducing the list back to 187.

[20] Commonly known as AB 2588.

Purpose: Establishes requirements in the CEC's decision-making process for an AFC that assures protection of environmental quality. The AFC is required to include information concerning air quality protection.

Administering Agency: CEC.

California Climate Change Regulatory Program

Authority: Stats. 2006, Ch. 488 and CA Health & Safety Code § 38500-38599

Purpose: The State of California adopted the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) on September 27, 2006, which requires sources within the state to reduce carbon emissions by approximately 25% by the year 2020. The California Climate Action Registry had already published protocols for voluntary reporting of GHG emissions from a number of sectors of the economy,[21] and the CARB has proposed draft regulations to limit GHG emissions from electric power plants and other specific source categories.[22] In addition, the CARB has issued draft guidance with recommended emission factors for calculating GHG emissions.[23]

AB 32 also sets the following milestone dates for the CARB to take specific actions:

June 30, 2007: Identify a list of discrete early action GHG emission reduction measures (first report published April 20, 2007, with additional measures adopted on October 25, 2007).

January 1, 2008: Establish a statewide GHG emission cap for 2020 that is equivalent to 1990 emissions.

January 1, 2008: Adopt mandatory reporting rules for significant sources of GHGs.

January 1, 2009: Adopt a scoping plan that will indicate how GHG emission reductions will be achieved from significant GHG sources through regulations, market-based compliance mechanisms, and other actions, including recommendation of a de minimis threshold for GHG emissions, below which sources would be exempt from reduction requirements.

January 1, 2011: Adopt regulations to achieve maximum technologically feasible and cost-effective GHG emission reductions, including provisions for both market-based and alternative compliance mechanisms.

January 1, 2012: Regulations adopted prior to January 1, 2010, become effective.

Senate Bill (SB) 97, adopted August 21, 2007, requires the California Office of Planning and Research (OPR) to develop CEQA guidelines "for the mitigation of GHG emissions or the effects of GHG emissions" by July 1, 2009. SB 97 further requires the Resources Agency Secretary to adopt these CEQA guidelines by January 1, 2010. Finally, SB 97 removes GHG

---

[21] California Climate Action Registry. Appendix to the General Reporting Protocol: Power/Utility Reporting Protocol – Reporting Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators and Electric Utilities, Version 1.0, April 2005 (http://www.climateregistry.org/Default.aspx?refreshed=true).

[22] CARB. Staff Report: Initial Statement of Reasons for Rulemaking, Public Hearing to Consider Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32), October 19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm.

[23] CARB. Attachments C to F, Supplemental Materials Document for Staff Report: Initial Statement of Reasons for Rulemaking, Public Hearing to Consider Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32), October 19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

emissions as a cause of action under CEQA for specified state-financed infrastructure projects until January 1, 2010.

The AFC is required to include the project's emission rates of "greenhouse gases" (CO_2, CH_2, N_2O, and SF_6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources."[24]

On January 25, 2007, the PUC and CEC jointly adopted an interim Greenhouse Gas Emissions Performance Standard (EPS) in an effort to help mitigate climate change. The EPS is a facility-based emissions standard requiring that all new long-term commitments for baseload generation to serve California consumers be with power plants that have emissions no greater than a combined-cycle gas turbine plant. That level is established at 1,100 pounds of CO_2 per megawatt-hour.[25]

Administering Agencies: CARB and CEC.

5.1.6.3 Local LORS

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county, regional, and unified (including the SJVAPCD). Local districts have principal responsibility for developing plans for meeting the NAAQS and California ambient air quality standards; for developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards; for implementing permit programs established for the construction, modification, and operation of sources of air pollution; for enforcing air pollution statutes and regulations governing non-vehicular sources; and for developing programs to reduce emissions from indirect sources.

San Joaquin Valley Unified Air Pollution Control District Attainment Demonstration Plans

Authority: H&SC §40914

Purpose: The SJVAPCD plans define the proposed strategies, including stationary source and transportation control measures and new source review rules, which will be implemented to attain and maintain the state ambient air quality standards. The relevant stationary source control measures and new source review requirements are discussed with individual SJVAPCD Rules and Regulations.

Administering Agency: SJVAPCD, with CARB oversight.

San Joaquin Valley Air Pollution Control District Rules and Regulations

Authority: H&SC §4000 et seq., H&SC §40200 et seq., indicated SJVAPCD Rules

Purpose: Establishes procedures and standards for issuing permits; establishes standards and limitations on a source-specific basis.

Administering Agency: SJVAPCD with EPA Region 9 and CARB oversight.

---

24 Appendix B (g) (8) (E) of the CEC siting regulations.

25 http://www.cpuc.ca.gov/PUC/061211_egyleadership.htm. Statutory authority based on Senate Bill 1368 (Stats. 2006, Ch. 598 and CA Public Utilities Code § 8340-8341). The numerical limit of 1,100 lbs CO_2 per MW-hr originated in PUC Interim Decision 07-01-039.

Rule 2010 (Permits Required) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to Construct from the SJVAPCD. Under Section 5.8.8 of Rule 2201 (New and Modified Stationary Source Review Rule), the SJVAPCD's Final Determination of Compliance acts as an authority to construct for a power plant upon approval of the project by the CEC.

Rule 2201 (New and Modified Stationary Source Review Rule) implements the federal NSR program, as well as the new source review requirements of the California Clean Air Act. The rule contains the following elements:

- Best available control technology (BACT)
- Emission offsets
- Air quality impact analysis (AQIA)

Best Available Control Technology

Best Available Control Technology (BACT) must be applied to any new or modified source resulting in an emissions increase exceeding any SJVAPCD BACT threshold shown in Table 5.1-32.

TABLE 5.1-32
District BACT Emission Thresholds

Pollutant	Threshold
PM	2 lb/day
NO_x	2 lb/day
SO_2	2 lb/day
VOC	2 lb/day
CO	2 lb/day

Source: Rule 2201, Section 4.1. Per Section 4.2,1, CO BACT threshold not applicable to facilities with total CO emissions less than 200,000 lb/year.

The SJVAPCD defines BACT as the most stringent emission limitation or control technique that:

- Has been achieved in practice for such emissions unit and class of source; or
- Is contained in any SIP approved by the EPA for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such limitation or control technique is not presently achievable; or
- Is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as determined by the APCO.

Emission Offsets

A new or modified facility with a stationary source NSR balance exceeding the SJVAPCD offset thresholds shown in Table 5.1-33 must offset all emissions increases at a ratio that varies according to the distance between the facility and the source of the offsets.

TABLE 5.1-33
District Offset Emission Thresholds

Pollutant	Threshold, lb/yr
NO_x	20,000
SO_2	54,730
CO	200,000*
VOC	20,000
PM	29,200

*Applies in CO attainment areas, including the project site. CO emissions in nonattainment areas are subject to a 30,000 lb/yr offset threshold.

Air Quality Impact Analysis
An air quality impact analysis must be conducted to evaluate impacts of emission increases from new or modified facilities on ambient air quality. Project emissions must not cause an exceedance of any ambient air quality standard.

Toxic Risk Management
The SJVAPCD's Risk Management Review Policy for Permitting New and Modified Sources provides a mechanism for evaluating potential impacts of air emissions of toxic substances from new, modified, and relocated sources in the SJVAPCD. The policy requires a demonstration that the source will not adversely impact the health and welfare of the public.

CEC Review
Rule 2201, Section 5.8 establishes a procedure for coordinating SJVAPCD review of power plant projects with the CEC AFC and Small Power Plant Exemption (SPPE) processes. Under this rule, the SJVAPCD reviews the AFC/SPPE and issues a Determination of Compliance for a proposed project, which is equivalent to an Authority to Construct upon approval of the project by the CEC. A permit to operate is issued following the CEC's certification of a project and demonstration of compliance with all permit conditions.

Rule 2540 (Acid Rain Program) requires that certain subject facilities comply with maximum operating emissions levels for SO_2 and NO_x, and must monitor SO_2, NO_x, and CO_2 emissions and exhaust gas flow rates. A Phase II acid rain facility, such as the project, must obtain an acid rain permit as mandated by Title IV of the 1990 Clean Air Act Amendments. A permit application must be submitted to the SJVAPCD at least 24 months before operation of the new unit commences.[26] The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations.

Rule 2520 (Federally Mandated Operating Permits) requires major facilities and Phase II acid rain facilities undergoing modifications to obtain an operating permit containing the

[26] Approximately by June 1, 2010, based on the assumption of initial operation on June 1, 2012.

federally enforceable requirements mandated by Title V of the 1990 Clean Air Act Amendments. A permit amendment application for a modification to an existing Title V facility must be submitted and an amended permit issued by the SJVAPCD prior to commencing operations at the facility. The application must present a process description, all new stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification.

SJVAPCD Prohibitory Rules

The general prohibitory rules of the SJVAPCD applicable to the project include the following:

Rule 4001 (New Source Performance Standards) requires compliance with applicable federal standards of performance for new or modified stationary sources.

Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) applies to gas turbines with a heat input in excess of 1 MMBtu/hr that commence construction after February 18, 2005. Subpart KKKK limits NO_x and SO_2 emissions from new gas turbines (and associated heat recovery steam generators) based on power output. The limits for turbines greater than 30 MW are 0.39 lb NO_x per MW-hr and 0.58 lb SO_2 per MW-hr.

Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) applies to boilers that burn fossil fuel with a heat input capacity equal to or less than 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr, and therefore would apply to the proposed project's 65 MMBtu/hr auxiliary boiler.

Rule 4002 – National Emissions Standards for Hazardous Air Pollutants: This rule implements the federal NESHAPS regulations discussed above in Section 5.1.6.1. The combustion turbine NESHAP is not applicable to the proposed project because the facility will not be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs).

Rule 4101 – Visible Emissions: Prohibits visible emissions as dark or darker than Ringelmann No. 1 for periods greater than three minutes in any hour.

Rule 4102 – Nuisance: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.

Rule 4201 – Particulate Matter Emission Standards: Prohibits PM emissions in excess of 0.1 grains per dry standard cubic foot (gr/dscf).

Rule 4301 – Fuel Burning Equipment: For "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer" (i.e., applies to auxiliary boiler, but not to gas turbines, or emergency standby generator and fire water pump engines), combustion contaminant (defined in Rule 1020 (Definition 3.12) as particulate matter from burning carbon-containing material) emissions are limited to:

0.1 grain of combustion contaminants per dry standard cubic foot @ 12% CO_2

10 pounds of combustion contaminants per hour

Sulfur compounds as SO_2 to 200 pounds per hour

NO_x as NO_2 to 140 pounds per hour

Rule 4305 – Boilers, Steam Generators, and Process Heaters Phase 2: Limits emissions from this equipment as follows:

Gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu)

CO emissions to 400 ppmvd @ 3% O_2

The rule also requires installation of CEMs for NO_x, CO and O_2.

Rule 4306 – Boilers, Steam Generators, and Process Heaters Phase 3: Limits emissions from this equipment as follows:

Category H boiler (i.e., annual heat input between 9 and 30 billion Btu/year) gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Standard Option, required by December 1, 2008, or

Category B boiler (i.e., heat input > 20 MMBtu/hr, except Category H) gas-fired NO_x emissions to 6 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Enhanced Option, required by June 1, 2007, and

CO emissions to 400 ppmvd @ 3% O_2.

The rule also requires installation of CEMs for NO_x, CO, and O_2

However, SJVAPCD has proposed to amend Rule 4306, Phase 3, and replace it with Rule 4320, described further below.

Rule 4320 – Advanced Emission Reduction Options For Boilers, Steam Generators, And Process Heaters Greater Than 5.0 MMBtu/hr: Limits emissions from this equipment as follows:

Category B boiler (i.e., heat input > 20 MMBtu/hr, except Category E) gas-fired NO_x emissions to 7 ppmvd @ 3% O_2 (0.007 lb/MMBtu) by January 1, 2012, or 5 ppmv or 0.0062 lb/MMBtu by January 1, 2013, or

Category E boiler (i.e., annual heat input between 1.8 and 9 billion Btu/year) gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Standard Option, required by January 1, 2014; and

CO emissions to 400 ppmvd @ 3% O_2.

The draft rule would also provide the option of paying an emissions fee in lieu of achieving the NO_x limits in the rule. Finally, the draft rule would also require use of a CEMS for NO_x, CO, and O_2 or implementation of an APCO-approved Alternate Monitoring System, as well as the use of an approved parametric monitoring system to track SO_x and PM_{10} emissions.

Rule 4351 – Boilers, Steam Generators, and Process Heaters Phase 1: Limits emissions from this equipment as follows:

Gas-fired NO_x emissions to 90 ppmvd @ 3% O_2 (0.10 lb/MMBtu)

CO emissions to 400 ppmvd @ 3% O_2.

The rule also requires monitoring of any NO_x control system

Rule 4703 – Stationary Gas Turbines: Limits emissions from stationary gas turbines as follows:

NO_x (Tier 2) emissions from combined-cycle stationary gas turbines rated > 10 MW to 3 ppmvd @15% O_2 for Enhanced Compliance Option, required after April 30, 2008

CO for GE Frame 7 gas turbine to 25 ppmv 15% O_2.

Rule 4703 also limits turbine startup periods to 2 hours unless a longer period is approved by SJVAPCD, EPA and CARB.

Rule 4801 – Sulfur Compounds: Prohibits sulfur compound emissions, calculated as SO_2, in excess of 0.2% (2,000 ppmv) from any source.

Rule 8011 – Fugitive PM_{10} Prohibitions, General Requirements: Sets forth definitions, applicability and administrative requirements for anthropogenic sources of PM_{10}.

Rule 8021 – Fugitive PM10 Prohibitions, Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities: Limits fugitive dust emissions from construction, demolition, excavation, and related activities.

Rule 8041 – Carryout and Trackout (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from construction carryout and trackout.

Rule 8051 – Open Areas (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from open areas larger than 3.0 acres containing more than 1,000 square feet of disturbed surface.

Rule 8061 – Paved and Unpaved Roads (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from constructed paved and unpaved roads on the project site.

Rule 8071 – Unpaved Vehicle/Equipment Traffic Areas (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from unpaved vehicle/equipment traffic areas experiencing more than 50 annual average daily trips.

5.1.7 Conformance of Facility

As addressed in this section, LEC is designed, and will be constructed and operated, in accordance with all relevant federal, state, and local requirements and policies concerning protection of air quality.

5.1.7.1 Consistency with Federal Requirements

The SJVAPCD has been delegated authority by the EPA to implement and enforce most federal requirements that may be applicable to the proposed project, including the new source performance standards and the Title IV and Title V Acid Rain and Operating Permit programs. Compliance with SJVAPCD regulations ensures compliance and consistency with the corresponding federal requirements as well. LEC will obtain an amended District Title V permit that includes applicable requirements for the modified power plant and includes Title IV Acid Rain provisions for the new unit.

EPA has retained the authority to issue PSD permits for sources in the SJVAPCD.

5.1.7.1.1 Federal Prevention of Significant Deterioration Program

EPA has promulgated PSD regulations for areas that are in compliance with national ambient air quality standards (40 CFR 52.21). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., specific national parks and wilderness areas).

The five principal areas of the federal PSD program are as follows:

- Applicability
- Best available control technology
- Pre-construction monitoring
- Increments analysis
- Air quality impact analysis

Each of these elements of the program is discussed individually below.

Applicability

The PSD program was established to allow emission increases (increments of consumption) that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded NAAQS. The federal 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 stationary source.[27] In the SJVAPCD, PSD requirements may be applicable for NO_x, SO_2 and CO, since the SJVAPCD is an attainment area for these pollutants. PSD requirements do not apply for VOC or PM_{10}, since the SJVAPCD is a nonattainment area for ozone and PM_{10}. The determination of applicability is based on evaluating the NO_x, SO_2, and CO emissions changes associated with the proposed project in addition to all other emissions changes at the same location since the applicable PSD baseline dates (40 CFR 52.21).

For the purposes of determining applicability of the PSD program requirements, the following regulatory procedure is used:

Emissions from the existing NCPA Lodi facility are compared with major source thresholds to determine whether the existing facility is a major source. This comparison is made in Table 5.1-34.

Maximum potential emissions from the LEC are compared with regulatory significance thresholds to determine whether the modification itself is major and thus may be subject to PSD. If the facility emissions exceed these thresholds, the proposed modification is subject to PSD review. The comparison in Table 5.1-35 indicates that the CO emissions from LEC exceed the major source threshold for the applicable source category,[28] and thus the project is subject to PSD review.

[27] These terms are defined in federal regulations at 40 CFR 52.21.

[28] The determination that a combined-cycle gas turbine system is considered a “electric utility steam generating unit” for purposes of determining applicability of PSD requirements was made in an August 6, 2001, letter from John Seitz, Director Office of Air Quality Planning and Standards, EPA, to Patrick M. Raher of Hogan & Hartson L.L.P (accessed at www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/cgtsd.pdf.

Contemporaneous emissions increases and decreases at the facility are included in the netting calculation to determine the net emissions changes at the facility. The net emissions changes are compared with the PSD significance levels in Table 5.1-36.

If an ambient impact analysis is required, the analysis is first used to determine if the impact levels are significant. The determination of significance is based on whether the impacts exceed regulatory significance levels (40 CFR 51.165) shown in Table 5.1-37.

TABLE 5.1-34
STIG Plant Emissions and PSD Major Source Thresholds

Pollutant	NCPA Lodi CT#2 Emissions (tpy)	PSD Major Source Thresholds (tpy)	Major?
NO_x	20.4	100	No
SO_2	5.7	100	No
CO	58.8	100	No

TABLE 5.1-35
LEC Proposed Emissions and PSD Major Source Thresholds

Pollutant	LEC Emissions (tpy)*	PSD Major Source Thresholds (tpy)	Major?
NO_x	71.5	100	No
SO_2	24.3	100	No
CO	254.9	100	Yes

Note: LEC emissions include CTG/HRSG, auxiliary boiler and cooling tower.

TABLE 5.1-36
Net Emission Increases and Significant Emissions Levels

Pollutant	Facility Net Increase (tpy)	PSD Significance Levels (tpy)	Are Increases Significant?
NO_x	71.5	40	Yes
SO_2	24.3	40	No
CO	254.9	100	Yes

TABLE 5.1-37
PSD Significant Impact Levels (SILs) and Class II Increments

Pollutant	Averaging Time	SILs[a]	Maximum Allowable Class II Increments[b]
NO_2	Annual	1.0 µg/m^3	25 µg/m^3
CO	1-hour 8-hour	2000 µg/m^3 500 µg/m^3	n/a[c] n/a

[a]40 CFR 51.165

[b]40 CFR 52.21

[c]No increments have been established for CO.

Table 5.1-34 shows that the existing NCPA Lodi turbine plant is not a major source under the PSD regulations. Table 5.1-35 shows that CO emissions from LEC will exceed the 100 ton major source threshold, so the project will be a major modification and thus subject to PSD review. Table 5.1-36 above shows that the NO_x emissions from the project will above the PSD significance threshold while the SO_x emissions will be below the threshold, so the project is subject to PSD review for NO_x and CO.

If the significant impact levels (SILs) are exceeded, an analysis is required to demonstrate that the allowable increments will not be exceeded, on a pollutant-specific basis. Increments are the maximum increases in concentration that are allowed to occur above the baseline concentration. These PSD increments are also shown in Table 5.1-37. There are no increments for CO. We note that annual NO_x emissions impacts from the project are below the SIL, as indicated in Table 5.1-27.

Best Available Control Technology

BACT is defined in 40 CFR 52.21(j) as:

"an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

A top-down BACT analysis is required for each pollutant subject to PSD review: that is, NO_x and CO. The required top-down BACT analysis is provided in Appendix 5.1C, and concludes that BACT for the proposed project is as shown in Table 5.1-38.

TABLE 5.1-38
BACT Required Under Federal PSD for LEC

Pollutant	Controlled Emission Rate	Control Technique
NO_x	2.0 ppmvd @ 15% O_2	Dry low-NO_x combustion with selective catalytic reduction
CO	3.0 ppmvd @ 15% O_2	Oxidation catalyst

Preconstruction Monitoring

To ensure that the impacts from the LEC will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the project area is necessary. If a source is subject to PSD review, PSD regulations generally require preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21(m)). However, a facility may be exempted from this requirement if the predicted air quality impacts of the facility do not exceed the de minimis levels. Modeled impacts from the LEC are compared with the de minimis levels in Table 5.1-39. Since modeled impacts are below the de minimis levels, the project may be exempted from the requirement.

TABLE 5.1-39
PSD Preconstruction Monitoring Exemption Levels

Pollutant	Averaging Period	Maximum Modeled Concentration	De minimis Level	Exceed Monitoring Threshold?
NO_2	annual	0.26 µg/m^3	14 µg/m^3	No
CO	8-hour average	111 µg/m^3	575 µg/m^3	No

The purpose of the preconstruction monitoring requirement is to verify that background concentrations are adequately characterized to ensure that the national ambient air quality standards are protected. With EPA's approval, a facility may rely on air quality monitoring data collected at District monitoring stations to satisfy the requirement for preconstruction monitoring. In such a case, in accordance with Section 2.4 of the EPA PSD guideline, the last 3 years of ambient monitoring data may be used if they are representative of the area's air quality where the maximum impacts occur due to the proposed source.

The background data need not be collected on site, as long as the data are representative of the air quality in the subject area (40 CFR 51, Appendix W, Section 9.2). Three criteria are applied in determining whether the background data are representative: (1) location, (2) data quality, and (3) data currentness.[29] These criteria are defined as follows:

Location: The measured data must be representative of the areas where the maximum concentration occurs for the proposed stationary source, existing sources, and a combination of the proposed and existing sources.

Data quality: Data must be collected and equipment must be operated in accordance with the requirements of 40 CFR Part 58, Appendices A and B, and PSD monitoring guidance.

Currentness: The data are current if they have been collected within the preceding 3 years and they are representative of existing conditions.

All of the data used in this analysis meet the requirements of Appendices A and B of 40 CFR Part 58, and thus all meet the criterion for data quality. All of the data have been collected within the preceding 3 years, and thus all meet the criterion for currentness. The location and overall representativeness of the data are discussed further below.

[29] Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA, 1987.

Data from the Hazelton Avenue monitoring station in Stockton, about 12 miles from the project site, were used to characterize CO and NO_2 air quality at the project site. This station was chosen because of its proximity to the site and because data recorded there represent area-wide ambient conditions rather than the localized impacts of any particular facility. Because of the proximity of the monitoring station to the project, the data measured there are believed to be representative of the areas where the maximum project impacts will occur. Further, since ambient CO concentrations are generally driven by motor vehicle emissions and tend to be localized, the use of CO background data collected at Hazelton Avenue, which is in central Stockton near the Interstate 99 freeway, is expected to overpredict CO concentrations in the areas where the proposed project would have significant impacts.

PSD Increment Consumption

The maximum modeled impacts from the LEC facility are compared with the NO_2 and CO significant impact levels in Table 5.1-40. These comparisons show that the maximum modeled NO_2 and CO impacts from the proposed project do not exceed the SILs. Therefore, no increments analysis is required for the proposed project.

TABLE 5.1-40
PSD Significant Impact Levels (SILs) and Class II Increments

Pollutant	Averaging Time	Maximum Modeled Concentration	SILsa	Exceeds SIL?
NO_2	Annual	0.3 µg/m^3	1.0 µg/m^3	No
CO	1-hour 8-hour	324 µg/m^3 111 µg/m^3	2000 µg/m^3 500 µg/m^3	1-Hour 8-Hour

Air Quality Impacts Analysis

Because the maximum modeled NO_2 and CO impacts from the project are below the significance thresholds, no additional assessment of the impacts on ambient air quality are required under the PSD program requirements. However, a complete ambient air quality impacts analysis for NO_2 and CO was provided in Section 5.1.5 above. The AQIA demonstrated that the project will not cause or contribute to any violations of federal standards for which PSD review applies.

Impacts on Growth, Soils, Vegetation, and Sensitive Species

PSD requirements include an assessment of the secondary impacts from projects subject to review. These potential secondary impacts include growth, soils and vegetation, and sensitive species.

Growth

There will be minimal growth associated with the proposed project during the construction phase, due to the relatively short 24-month construction schedule and the broad regional availability of construction labor in the southern Sacramento and northern San Joaquin Valleys. Further, no direct project-related long-term growth is expected to occur in the area because only 21 additional permanent employees will be added as a result of the new plant.

The proposed project will not induce growth as a result of the additional power available. NCPA provides power to member agencies in northern California and is not a local power provider. The project is being developed by LEC in response to the growth in demand in the northern part of the state and will be available to back up non-fossil supplies such as hydro, solar and wind generating resources.

Vegetation, Soils and Sensitive Species

The LEC will be located in an area that is primarily agricultural. Criteria for evaluating impacts on soils and vegetation are provided by EPA guidance.[30] This document includes minimum impact levels for effects on sensitive vegetation and crops. Modeled project impacts are compared with these impact levels in Table 5.1-41 to demonstrate that no adverse impacts on vegetation are expected as a result of the project.

TABLE 5.1-41
Project Impacts to Vegetation and Sensitive Species

Pollutant	Averaging Period	Modeled Project Impacts ($\mu g/m^3$)	Ambient Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Minimum Ambient Concentration for Effects on Sensitive Plants ($\mu g/m^3$)
NO_2	4 hours[a]	27.5	163.6	191	3,760
	8 hours[a]	27.5	163.6	191	3,760
	1 month[a]	27.5	163.6	191	564
	Annual	0.3	34.0	34.3	94
SO_2	1 hour	10.4	46.8	57.2	917
	3 hours	7.6	28.6	36.2	786
	Annual	0.1	2.7	2.8	18
CO	1 week[b]	111	3,178	3,289	1,800,000

[a]Maximum modeled 1-hour average NO_2 concentrations used to conservatively represent impacts for averaging periods up to one month.

[b]Maximum modeled 8-hour average CO concentration used to conservatively represent 1-week average impact.

Project impacts on agriculture and soils are discussed in detail in Section 5.11 of the AFC. Project impacts on fauna are discussed under Biological Resources, Section 5.2 of the AFC.

Class I Area Impact Analysis and Class II PSD Significance Thresholds

In general, projects located within 100 km of Class I areas are required to evaluate impacts to visibility and other air quality-related values at those Class I areas as part of a PSD permit evaluation. The nearest Class I areas and their distances from the project are listed below.

Mokelumne Wilderness	106 km
Emigrant Wilderness	120 km
Desolation Wilderness	122 km
Yosemite National Park	124 km
Point Reyes National Seashore	127 km

[30] Smith, A. E., and J. B. Levenson. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*. Research Triangle Park, N.C.: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, 1980.

Pinnacles Wilderness 180 km

Since all of these areas are more than 100 km from the project site, visibility and AQRV analyses should not be required. However, since the Mokelumne Wilderness is only slightly more than 100 km away, an assessment could otherwise be required for that area. The Federal Land Managers (FLMs) have developed a screening methodology for determining whether a proposed project is likely to have a significant impact on a Class I area when located within, or near to, the 100 km threshold. Under this procedure, the estimated sum of maximum NO_x, SO_x, and PM_{10} emissions (in tons per year) from the project is divided by the distance of each Class I areas from the project (in km) (National Park Service, 2007). The sum of the NO_x, SO_2, and PM_{10} emissions from the project is 139.8 tons.[31] Using the distance to the closest Class I area, 106 km, the quotient is 1.32. Because this quotient is substantially less than the FLM threshold level of 10, it is expected that even if the project is subject to PSD review it will not be required by the FLMs to evaluate impacts to visibility and other air quality related values at Class I areas.

5.1.7.1.2 Federal New Source Performance Standards

The Standards of Performance for New Stationary Sources are source-specific federal regulations, limiting the allowable emissions of criteria pollutants (i.e., those that have a national ambient air quality standard). These regulations apply to certain sources depending on the equipment size, process rate, and/or the date of construction, modification, or reconstruction of the affected facility. Recordkeeping, reporting, and monitoring requirements are usually necessary for the regulated pollutants from each subject source; the reports must be regularly submitted to the reviewing agency (40 CFR 60.4). This program has been delegated by EPA to the SJVAPCD.

Subpart KKKK, the NSPS for Stationary Gas Turbines, and Subpart Dc, the NSPS for small Commercial-Institutional-Industrial Boilers, are applicable to the equipment proposed for this project. Subpart KKKK limits NO_x and SO_2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 30 MW are 0.39 lb NO_x per MW-hr and 0.58 lb SO_2 per MW-hr. The emission limits of 2.0 ppmc NO_x and 0.56 ppmc SO_2 proposed for the LEC turbine and duct burners are well below the Subpart KKKK limits, as shown in Table 5.1-42.

TABLE 5.1-42
Compliance With 40 CFR 60 Subpart KKKK

Pollutant	Proposed Permit Limits			Subpart KKKK Limit, lb/MW-hr
	ppmc	lb/hr	lb/MW-hr (max)	
NO_x	2.0	15.25	0.05	0.39
SO_2	0.57	6.0	0.02	0.58

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the LEC gas turbine/HRSG will be equipped with a continuous NO_x emissions monitor, ongoing annual performance testing will not be required under the NSPS.

[31] 71.5 tons (NOx) plus 24.3 tons (SO_2) plus 44.0 tons (PM_{10}).

Subpart Dc limits SO_2 and PM_{10} emissions from new small boilers. Because the LEC auxiliary boiler will burn only natural gas, its permitted emissions will be well below any applicable limits in Subpart Dc.

5.1.7.1.3 National Emissions Standards for Hazardous Air Pollutants

The NESHAPs are either source-specific or pollutant-specific regulations, limiting the allowable emissions of hazardous air pollutants from the affected sources (40 CFR Part 63). Unlike criteria air pollutants, hazardous air pollutants do not have a national ambient air quality standard but have been identified by EPA as causing or contributing to the adverse health effects of air pollution.

NESHAPs are applicable only to major sources of HAPs. The assessment of noncriteria pollutant emissions from the facility in Section 5.1.3.6 included a calculation of total HAP emissions from the new and existing facilities after modification. Since HAP emissions do not exceed 10 tpy for any individual HAP or 25 tpy in total, the project is not a major source of HAPs. Therefore, LEC is not subject to any NESHAP requirements.

5.1.7.1.4 Federal Clean Air Act Amendments of 1990

In November 1990, substantial revisions and updates to the federal Clean Air Act were signed into law. This complex enactment addresses a number of areas that could be relevant to the proposed LEC, such as more extensive permitting requirements and new EPA mandates and deadlines for developing rules to control air toxic emissions. The most significant of the new provisions applicable to this project are the Title IV acid rain and Title V operating permit programs.

Title IV—Acid Rain

As a Phase II Acid Rain facility, the LEC will be required to provide sufficient allowances for every ton of SO_2 emitted during a calendar year. LEC will also be required to install and operate a NO_x CEMS that complies with program requirements. SJVAPCD has been delegated the authority to implement the acid rain permitting program. Compliance with program requirements is discussed below with other local district requirements.

Title V—Operating Permits

This title establishes a comprehensive operating permit program for major stationary sources (42 USC §7661 et seq.). Under the Title V program, a single permit is required that includes a listing of all the stationary sources, applicable regulations, requirements, and compliance determinations.

SJVAPCD's Title V Program (Rule 2520) has been approved by EPA. Consequently, SJVAPCD has received delegation to implement the Title V program. SJVAPCD Title V permit programs applicable to this project are summarized below.

5.1.7.2 Consistency with State Requirements

State law sets up local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. As discussed above, the project is under the local jurisdiction of the SJVAPCD, and compliance with SJVAPCD regulations will assure compliance with state air quality requirements.

5.1.7.2.1 California Clean Air Act

AB 2595, the California Clean Air Act (CAA) was enacted by the California Legislature and became law in January 1989. The CAA requires the local air pollution control districts to attain and maintain both the federal and state ambient air quality standards at the "earliest practicable date." The CAA contains several milestones for local districts and the CARB. SJVAPCD was required to submit to the CARB an air quality plan, with updates as necessary, defining the program for meeting the required emission reduction milestones in the San Joaquin Valley.

Air quality plans must demonstrate attainment of the state ambient air quality standards and must result in a five percent annual reduction in emissions of nonattainment pollutants (ozone, PM_{10}, $PM_{2.5}$, and associated precursors) in a given district (H&SC §40914). A local district may adopt additional stationary source control measures or transportation control measures, revise existing source-specific or new source review rules, or expand its vehicle inspection and maintenance program (H&SC §40918) as part of the plan. District air quality plans specify the development and adoption of more stringent regulations to achieve the requirements of the Act. The applicable regulations that will apply to LEC are included in the discussion of District prohibitory rules in Section 5.1.7.3.

5.1.7.2.2 Greenhouse Gas Initiatives

In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (CARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020. To achieve this, CARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The CARB adopted early action GHG reduction measures in October 2007 and will establish statewide emissions caps by economic "sectors" in 2008. By January 1, 2009, CARB will adopt a scoping plan that will identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. CARB staff will then draft regulatory language to implement its plan and will hold additional public workshops on each measure, including market mechanisms.

SB 1368, also enacted in 2006, and regulations adopted by the CEC and the Public Utilities Commission pursuant to the bill, prohibits utilities from entering into long-term commitments with any baseload facilities that exceed the Emission Performance Standard of 0.500 metric tones of CO_2 per megawatt-hour (1,100 pounds CO_2/MWh). Specifically, the Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California. If a project, in-state or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS.

Since the project is permitted for more than 60 percent annual capacity factor, it must emit less than 0.500 mt CO_2/MWh to meet the EPS. The project is expected to emit 0.376 mt

CO_2/MWh, (CO_2, not CO_2-equivalent), as shown in Table 5.1-22 above. Therefore, the facility will comply with the EPS. As the CEC's 2007 Integrated Energy Policy Report[32] noted:

"New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants." (p. 184)

Thus, in both the context of the California Environmental Quality Act and CEC's Integrated Energy Policy Report, the proposed project would not be expected to cause a significant cumulative impact and furthers the state's strategy to reduce fuel use and GHG emissions. Further, even though it is possible to quantify how many gross GHG emissions are attributable to a project, it is difficult to determine whether this will result in a net increase of these emissions, and, if so, by how much. Therefore, it would be speculative to conclude that any given project results in a cumulatively significant adverse impact resulting from greenhouse gas emissions.

At this time, neither the state nor the APCD has adopted thresholds of significance or methodologies for analyzing GHG emission impacts under CEQA. The State Office of Planning and Research has recently begun the process of drafting proposed guidelines for analyzing GHG emissions, but these guidelines are not expected to be adopted until January 2010. Additionally, CARB is currently in the process of drafting a scoping plan to achieve the emission reduction targets of AB 32. In the interim period while the AB 32 and CEQA GHG-related regulatory programs are being developed, projects may be judged on whether they will hinder the emission reduction goals of AB 32.

The CEC has issued several decisions concerning projects subject to its decision since passage of AB 32. Recently, the Final Commission Decision on the 660 MW Colusa Generating Station (CGS) discussed the schedule by which the CARB will develop regulations to manage GHG emissions and imposed a condition of certification AQ-SC8 that "…requires the project owner to report the quantities of relevant greenhouse gases emitted as a result of electric power production." More important was the following finding: "We find that AQ-SC8, with the reporting of GHG emissions, will enable the project to be consistent with the regulations and policies described above" (referring to AB 32 and Senate Bill 1368 (Electricity Greenhouse Gas Emissions Standards)). As a routine matter, the CEC includes such reporting in its decisions. Such GHG emission reporting is already carried out on a regular basis by NCPA in its annual reports to the California Climate Action Registry under the specific requirements of the Power/Utility Reporting Protocol (April 2005) for each of its generating units.

In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing

[32] CEC-100-2007-008-CMF, December 5, 2007, accessed at http://www.energy.ca.gov/2007_energypolicy/

the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

5.1.7.3 Consistency with Local Requirements: SJVAPCD

The SJVAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations in the eight counties[33] within the SJVAPCD. The project is subject to SJVAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from toxic air pollutants. The following sections include the evaluation of facility compliance with the applicable SJVAPCD requirements.

Under the regulations that govern new sources of emissions, the project is required to secure a preconstruction Determination of Compliance from the SJVAPCD (Rule 2201), as well as demonstrate continued compliance with regulatory limits when the project becomes operational. The preconstruction review includes demonstrating that the project will use BACT and will provide any necessary emission offsets.

Applicable BACT thresholds are shown in Table 5.1-43, along with anticipated potential emissions from each unit and criteria pollutant. SJVAPCD Rule 2201 requires BACT for each unit emitting CO, NO_x, VOC, SO_x, or PM_{10} (criteria pollutants) in excess of 2.0 pounds per highest day (with facility-wide CO emissions in excess of 200,000 pounds per year). The calculation of facility emissions was discussed in Section 5.1.3.

TABLE 5.1-43
Best Available Control Technology Requirements

		Turbine/HRSG		Auxiliary Boiler	
Pollutant	**BACT Applicability Threshold (lbs/day)**	**Maximum Emissions (lbs/day)**	**BACT Required?**	**Maximum Emissions (lbs/day)**	**BACT Required?**
NO_x	2	864.9	yes	6.5	yes
VOC	2	179.8	yes	3.3	yes
SO_2	2	136.4	yes	2.2	yes
PM_{10}	2	240.0	yes	5.6	yes
CO*	2	5,641.9	yes	28.5	yes

*Facility-wide CO emissions exceed 200,000 lb/year, therefore BACT threshold of 2 lb/day applies to all new equipment.

As shown in Table 5.1-43, BACT is required as follows:

- Turbine/HRSG: NO_x, VOC, SO_2, CO, and PM_{10}
- Auxiliary boiler: NO_x, VOC, SO_2, CO, and PM_{10}.

In addition, since the cooling tower daily emissions of 10.8 lb/day exceed the 2 lb/day BACT threshold, BACT is also required for PM_{10} emissions from the cooling tower.

[33] Including the portion of Kern County that is within the SJVAPCD boundaries.

BACT for the applicable pollutants was determined by reviewing the SJVAPCD BACT Clearinghouse,[34] the South Coast Air Quality Management District (SCAQMD) BACT Guidelines,[35] the CARB BACT Determinations,[36] and EPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC).[37] A summary of the review is provided in Appendix 5.1C.

NO_x BACT – BACT for NO_x emissions from the gas turbine will be the use of low NO_x emitting equipment and add-on controls. The Applicant has selected a gas turbine equipped with dry low-NO_x combustors. The gas turbines will generate approximately 9 ppmvd NO_x, corrected to 15 percent O_2, at the entry to the HRSGs. In addition, the turbines will be equipped with an SCR system to further reduce NO_x emissions to 2.0 ppmvd NO_x, corrected to 15 percent O_2. Hourly average NO_x emissions will not exceed 2.0 ppmvd @ 15% O_2 (excluding startups and shutdowns). The duct burner will also be exhausted to the SCR system; therefore, BACT for the duct burner is the same 2.0 ppmvd NO_x level, corrected to 15 percent O_2. A review of recent BACT determinations for NO_x from gas turbines is shown in Appendix 5.1C.

BACT for NO_x emissions from the auxiliary boiler will be the use of low NO_x emitting equipment. The project has selected a boiler equipped with ultra low-NO_x burners. The boiler with low NO_x burners will generate less than 7 ppmvd NO_x, corrected to 3 percent O_2. The SJVAPCD BACT guidelines indicated that BACT from a boiler (> 20 MMBtu/hr heat input) with highly variable loads or high turndown ratios is a NO_x exhaust concentration not to exceed 15 ppmvd, corrected to 3 percent O_2; therefore, the project will meet or exceed the BACT requirements for NO_x. A review of recent BACT determinations for NO_x from boilers is shown in Appendix 5.1C.

CO BACT – BACT for CO emissions will be achieved by use of a gas turbine equipped with a dry low-NO_x combustor and an oxidation catalyst. Dry low-NO_x combustors emit low levels of combustion CO while still maintaining low- NO_x formation. In addition, the project will use an oxidation catalyst system to further reduce CO emissions to 3.0 ppmvd, corrected to 15 percent O_2 (excluding startup and shutdown periods). SJVAPCD BACT Guideline 3.4.2 C indicates that BACT from a large gas turbine with heat recovery is 4.0 ppmvd CO, corrected to 15 percent O_2. CO emissions from the proposed gas turbines will meet this BACT requirement. A review of recent BACT determinations for CO from gas turbines is provided in Appendix 5.1C.

The auxiliary boiler will achieve a CO emission rate of 50 ppmvd, corrected to 3 percent O_2. While the SJVAPCD BACT guidelines do not include a specific BACT level for CO, guidelines in other districts (e.g., SCAQMD, BAAQMD) indicate that BACT for boilers is 50 ppmvd at 3 percent O_2. The proposed CO emission rate is consistent with these BACT determinations.

VOC BACT – BACT for VOC emissions will be achieved by use of the gas turbine dry low-NO_x combustor. As in the case of CO emission formation, dry low- NO_x combustors that result in low combustion VOC while still maintaining low NO_x levels. BACT for VOC

[34] SJVAPCD. BACT Clearinghouse, http://www.valleyair.org/busind/pto/bact/bactchidx.htm.
[35] SCAQMD. BACT Guidelines, http://www.aqmd.gov/bact/BACTGuidelines.htm.
[36] CARB. Statewide BACT, http://www.arb.ca.gov/bact/bact.htm.
[37] EPA. RBLC, http://cfpub.epa.gov/rblc/htm/bl02.cfm.

emissions from combustion devices has historically been the use of best combustion practices. With the use of the dry low- NO_x combustors and with the duct burner emission level, VOC emissions will be limited to 2.0 ppmvd, corrected to 15 percent oxygen. Without duct firing, VOC emissions will be limited to 1.4 ppmvd, corrected to 15 percent oxygen. This level of emissions is consistent with the SJVAPCD's BACT guidelines for large gas turbines.

BACT for VOC emissions for the auxiliary boiler will be achieved by the use of natural gas fuel and good combustion practices. The VOC emissions will be 10.0 ppmvd, corrected to 3 percent O_2. SJVAPCD BACT Guideline 1.1.3 indicates that VOC BACT for boilers greater than 20 MMBtu/hr is natural gas fuel and good combustion practices. The low NO_x burners are designed to minimize incomplete combustion and therefore minimize VOC emissions.

PM_{10} BACT – For the turbine, duct burner and auxiliary boiler, BACT for PM_{10} is good combustion practices and the use of natural gas fuel, which will result in minimal particulate emissions. The turbine and HRSG will also utilize an air inlet filter and lube oil vent coalescer to minimize PM_{10} emissions.

For the cooling tower, drift eliminators will be used to keep the drift rate below 0.0005%. This is the drift rate commonly achieved by cooling towers of this type and in combination with the proposed 3000 ppm limit on TDS in the cooling tower water, will minimize PM_{10} emissions from the cooling tower.

SO_2 BACT – SO_2 emissions will be kept at a minimum by firing clean burning natural gas fuel with a maximum sulfur content of 1.0 gr/100 scf.

In addition to the BACT requirements, SJVAPCD Rule 2201 requires the project to provide emission offsets when emissions exceed specified levels on a pollutant-specific basis. Offsets for CO are not required because the air quality impact analysis is expected to demonstrate to the satisfaction of the APCO that the ambient air quality standards for CO are not currently being violated and that the project would not cause or contribute to a violation of the standards (see Table 5.1-29). As shown in Table 5.1-44, the project must provide emission offsets for NO_x, PM_{10}, SO_2, and VOC emissions.

TABLE 5.1-44
SJVAPCD Offset Requirements and Project Emissions

Pollutant	Emissions from Existing Facility, tpy	Emissions from New Facility, tpy	District Offset Threshold, tpy	Offsets Required
VOC	25.9	17.5	10.0	Yes
NO_x	20.4	71.5	10.0	Yes
SO_2	5.7	24.3	27.4	Yes
PM_{10}	8.8	44.0	14.6	Yes

The NSR rule requires emission reductions to be provided at an offset ratio of between 1 and 1.5 to 1, depending upon the distance between the source and the offset location. Interpollutant offsets are permitted, at the discretion of the APCO. Appendix 5.1F presents a demonstration of compliance with the offset and mitigation requirements for the proposed project. The demonstration includes a listing of credits owned by the Applicant, a quarterly

reconciliation of offset requirements and ERCs, and an analysis of interpollutant offset ratios to be used to fulfill the PM_{10} offset and mitigation requirements for the project.

The NSR rule also only allows project approval if air quality modeling results indicate emissions will not cause or exacerbate the violation of the applicable ambient air quality standards, after accounting for mitigation. The modeling analyses in Section 5.1.5 show that with the exception of PM_{10}, facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards. Because the SJVAB is currently a nonattainment area for state PM_{10} and federal $PM_{2.5}$ ambient air quality standards, any increase in PM_{10} emissions has the potential to exacerbate existing violations. The Applicant will be providing PM_{10} offsets to mitigate the impact of the emissions increase; as a result, the required finding can be made for PM_{10} as well.

Rule 2520, Federal Part 70 Permits (Title V permit program) applies to major sources on a pollutant-specific basis. The Phase II acid rain requirements of Rule 2540 are also applicable to the facility. As a Phase II Acid Rain facility, the project will be required to provide sufficient allowances for every ton of SO_2 emitted during a calendar year. The applicant will file the appropriate applications for modifications to the existing Title V and acid rain permits, and will obtain any additional offsets, as needed, on the open trade market. The project will also install and operate the required continuous emissions monitoring systems (CEMS).

The general prohibitory rules of the SJVAPCD applicable to the project and the determination of compliance follow.

Rule 4001 (New Source Performance Standards). Subparts Dc and KKKK of this rule require monitoring of fuel; impose limits on the emissions of NO_x, PM, and SO_2; and require source testing of stack emissions, process monitoring, and data collection and recordkeeping. All of the BACT limits imposed on the facility will be more stringent than the requirements of the NSPS emission limits. Monitoring and recordkeeping requirements for BACT will be more stringent than the requirements in this rule; therefore, the project will comply with the NSPS regulations.

Rule 4101 (Visible Emissions). Any visible emissions from the project will not be darker than No. 2 when compared to a Ringlemann Chart for any period(s) aggregating 3 minutes in any hour. Because the facility will burn clean fuels, the opacity standard of not greater than 20 percent for a period or periods aggregating 3 minutes in any hour and the particulate emission concentrations limit of 0.15 grains per standard cubic feet of exhaust gas volume will not be exceeded.

Rule 4102 (Public Nuisance). The facility will not emit significant quantities of odorous or visible substances; therefore, the facility will comply with this regulation.

Rule 4201 (Particulate Matter Emission Standards). The emission units will have particulate matter emission rates well below the limits of the rule. The maximum grain loading for the turbines and duct burners (from Table 5.1A-1, Appendix 5.1A) is 0.0022 gr/dscf, well below the 0.1 gr/dscf limit of the rule.

Rule 4320 (Advanced Emission Reduction Options For Boilers, Steam Generators, And Process Heaters Greater Than 5.0 MMBtu/hr). The auxiliary boiler will comply with the requirements of this proposed rule by limiting NO_x emissions to not more than 7 ppmc. The

applicant will submit to the APCO for approval proposals for an Alternate Monitoring System for NO_x and CO emissions and a parametric monitoring system to track SO_x and PM_{10} emissions.

Rule 4703 (Stationary Gas Turbines). Emissions from the new turbine will be well below the limits in this rule. The applicant is requesting SJVAPCD's approval of startup times up to 6 hours as necessary. As discussed in the BACT analysis of startup emissions provided in Appendix 5.1C, startup emissions from the CTG will be minimized through the use of the Rapid Response technology. However, because there is no operational experience with this technology, LEC cannot ensure that this new technology will allow the turbine to come into compliance with the Rule 4703 NO_x and CO limits within 2 hours.

Rule 4801 (Sulfur Compound Emissions). Because the project will use only natural gas fuel, all of the Rule 4801 limits will easily be complied with.

Rule 7012 (Hexavalent Chromium – Cooling Towers). The cooling tower will not use hexavalent chromium.

Rule 8011 (Fugitive PM_{10} Prohibitions, General Requirements). This rule includes definitions, exemptions, requirements and fees related to the control of fugitive PM_{10}.

Rule 8021 (Fugitive PM_{10} Prohibitions, Construction, Demolition, Excavation, Extraction and other Earthmoving Activities). This rule requires the use of specified control measures to control fugitive dust emissions during construction activities, and the submittal of a Dust Control Plan prior to the commencement of construction. NCPA has committed to use dust control measures during construction to minimize fugitive dust emissions.

A summary of LORS compliance is provided in Table 5.1-45 below.

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
Federal					
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC 7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (40 CFR 51 & 52) (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	EPA	Issues PSD permit with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.1; p. 5.1-59 et seq Appendix 5.1C
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-70 et seq Appendix 5.1C
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NO_x and SO_2 emissions.	SJVAPCD with EPA oversight	Issues Acid Rain (FDOC/ATC) permit after review of application.	Application to be made within 12 months of start of facility operation; LEC not subject to this program.	§5.1.7.1.4; p. 5.1-67
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD with EPA oversight	Issues amended Title V permit after review of application.	Application for amendment to be made at least 12 months prior to start of facility operation.	§5.1.7.1.4; p. 5.1-67
CAA §111, 42 USC §7411, 40 CFR Part 60 (New Source Performance Standards [NSPS])	Establishes national standards of performance for new stationary sources.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.2; p. 5.1-66
CAA §112, 42 USC §7412, 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants [NESHAPs])	Establishes national emission standards for hazardous air pollutants.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.3; p. 5.1-66

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
State					
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
H&SC §44300-44384; California Code of Regulations (CCR) §93300-93347 (Toxic "Hot Spots" Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Screening HRA submitted before start of construction.	§5.1.7.2.2; p. 5.1-68 §5.9 (Public Health)
California Public Resources Code §25523(a); 20 CCR §1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that CEC's decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	CEC	After project review, issues FDOC/ATC with conditions limiting emissions.	CEC approval of AFC, including all conditions contained in FDOC, to be obtained before start of construction.	n/a (conformance demonstrated through submittal of AFC)
Global Warming Solutions Act and other GHG reduction measures	Minimize emissions of GHG from all sources in CA	CEC and CARB	After project review, issues conditions of certification requiring reporting of GHG emissions	CEC approval of AFC, including all conditions contained in FDOC, to be obtained before start of construction.	§5.1.7.2.2; p. 5.1-68
Local					
SJVAPCD Rule 4001 (New Source Performance Standards [NSPS])	Establishes national standards of performance for new stationary sources.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4002 (National Emission Standards for Hazardous Air Pollutants [NESHAPs])	Establishes national emission standards for hazardous air pollutants.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.3; p. 5.1-66

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
SJVAPCD Rule 4102 (Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 2201 (New Source Review)	NSR: Requires that preconstruction review be conducted for all proposed new or modified sources of air pollution, including BACT, emissions offsets, and air quality impact analysis.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-69-73 Appendix 5.1C
SJVAPCD Rule 2520 (Title V)	Implements operating permits requirements of CAA Title V	SJVAPCD with EPA oversight	Issues amended Title V permit after review of application.	Application for amendment to be made prior to start of facility operation.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 2540 (Title IV)	Acid rain regulations of CAA Title IV.	SJVAPCD with EPA oversight	Title IV requirements incorporated into FDOC/ATC and Title V permit after review of application	Application to be submitted two years before start of facility operation. LEC not subject to this program.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4101 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 2 for periods greater than 3 minutes in any hour.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4201 (Particulate Matter Concentration)	Limits PM emissions to less than 0.10 gr/dscf.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p 5.1-73
SJVAPCD Rules 4306 and 4320 (proposed) (Boilers, Steam Generators and Process Heaters)	Limits NO_x and CO emissions from boilers, steam generator and process heaters	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p 5.1-73
SJVAPCD Rule 4703 (Stationary Gas Turbines)	Limits NO_x emissions from gas turbines	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
SJVAPCD Rule 4801 (Sulfur Compound Emissions)	Limits sulfur emissions from permitted sources	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Regulation VIII (Fugitive PM_{10} Prohibition)	Requires control of fugitive PM_{10} emissions from various sources	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.3.8; p. 5.1-32-33 Appendix 5.1E §5.1.7.3; p. 5.1-74

5.1.7.4 Screening Health Risk Assessment

Pursuant to the SJVAPCD Integrated Air Toxics program, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed project. The impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

A screening health risk assessment has been prepared that includes the CTG/HRSG and the auxiliary boiler. The results of the revised screening health risk assessment are presented in Table 5.1-46. A detailed discussion of the screening health risk assessment procedures and assumptions is provided in Appendix 5.1D to this application.

TABLE 5.1-46
Screening Health Risk Assessment Results

Source	Residential Cancer Risk (in one million)	Worker Cancer Risk (in one million)	Chronic Health Hazard Index	Acute Health Hazard Index
Gas Turbine/ HRSG, Aux. Boiler	0.43	0.04	0.08	0.05

The maximum cancer risk from the facility is well below the 1 in one million level that is considered to be significant. The acute and chronic health hazard indices are well below 1.0.

5.1.8 Cumulative Air Quality Impacts Analysis

An analysis of potential cumulative air quality impacts that may result from the project and other reasonably foreseeable projects is generally required only when project impacts are significant.

To ensure that potential cumulative impacts of the project and other nearby projects are adequately considered, a cumulative impacts analysis has been conducted in accordance with the protocol included as Appendix 5.1G. The analysis demonstrates that the project will not cause or contribute to any significant cumulative air quality impacts.

5.1.9 Mitigation Measures

Mitigation will be provided for project emissions in the form of offsets and the installation of BACT, as required under SJVAPCD regulations. The cumulative air quality impacts analysis described in Appendix 5.1G shows that the project will not result in significant cumulative impacts and that sufficient ERCs are being provided to mitigate all project emissions.

5.1.10 Agencies and Agency Contacts

Each level of government has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project. The other air agencies having permitting authority for this project are shown in Table 5.1-47. The applicable federal LORS and compliance with these requirements were discussed in detail in Sections 5.1-6 and 5.1-7 above. The SJVAPCD will review the application for a District

permit. It will provide the CEC with a Determination of Compliance, which provides the CEC with information on what the facility must do in order to be in compliance with air quality requirements. Additionally, the SJVAPCD is responsible for issuance of the federal Operating (Title V) permit. An application for the federal permit will be submitted in a timely fashion.

TABLE 5.1-47
Agency Contacts for Air Quality

Agency	Authority	Contact
EPA Region IX	PSD permit issuance, enforcement	Gerardo Rios, Chief Permits Office EPA Region IX 75 Hawthorne Street San Francisco, CA 94105 (415) 744-1259
California Air Resources Board	Regulatory oversight	Mike Tollstrup, Chief Project Assessment Branch California Air Resources Board 2020 L Street Sacramento, CA 95814 (916) 322-6026
San Joaquin Valley Air Pollution Control District	Permit issuance, enforcement	Rupi Gill San Joaquin Valley Air Pollution Control District 4800 Enterprise Way Modesto, CA 95356-8712 (209) 557-6446

5.1.11 Permits and Permit Schedule

An Authority to Construct is required in accordance with SJVAPCD Rule 2010. A complete application for an Authority to Construct is being filed with the SJVAPCD prior to submittal to the CEC of the complete AFC. A PDOC is expected within approximately 180 days after acceptance of the permit application as complete, or by approximately March 1, 2009.

The project will also require a PSD permit from EPA. The PSD permit application will be filed within a week of submittal of the AFC.

5.1.12 References

California Air Resource Board (CARB). http://www.arb.ca.gov/adam.

California Air Resource Board (CARB). 1989. Reference Document for California Statewide Modeling Guideline. April.

California Air Resource Board (CARB). 1997. Emission Inventory Criteria and Guidelines Report for the Air Toxics “Hot Spots” Program. May 15.

California Air Resource Board (CARB). 1999. Proposed Guidance for Power Plant Siting and Best Available Control Technology. June 23.

California Air Resource Board (CARB). 2008. Hotspots Analysis and Reporting Program (HARP). Downloaded from http://www.arb.ca.gov/toxics/harp/harp.htm. May.

California Air Resource Board (CARB). 2006. California Air Toxics Emission Factor database at http://www.arb.ca.gov/ei/ catef/catef.htm. Accessed July 2008.

CAPCOA. 1993. Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines. October.

Cole, Henry S. and John E. Summerhays (1979). *A review of techniques available for estimating short-term NO2 concentrations*, Journal of the Air Pollution Control Association, Volume 29, Number 8, pages 812-817, August 1979.

Nappo, C. J. et al. (1982). *The Workshop on the Representativeness of Meteorological Observations*, June 1981, Boulder, Co. Bull. Amer. Meteor. Soc., Vol. 63, No. 7, pp. 761-764. American Meteorological Society, Boston, MA.

California Office of Environmental Health Hazard Assessment (OEHHA). 2002. Air Toxics Hot Spots Program Risk Assessment Guidelines. Part II. Technical Support Document for Describing Available Cancer Potency Factors. December.

California Office of Environmental Health Hazard Assessment (OEHHA). Acute and Chronic Exposure Levels Developed by OEHHA as of May 2008.

Smith, T. B., W.D. Sanders, and D.M. Takeuchi. 1984. Application of Climatological Analysis to Minimize Air Pollution Impacts in California, Final Report on CARB Agreement A2-119-32. August.

Stull, Roland B. 1988. An Introduction to Boundary Layer Meteorology, Chapter 9.

U.S. Department of Commerce, Weather Bureau. 1959. Climate of the States—California. December.

U.S. Environmental Protection Agency (EPA). 1985. Guideline for Determination of Good Engineering Practice Stack Height. June.

U.S. Environmental Protection Agency (EPA). 1987. Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007. May.

U.S. Environmental Protection Agency (EPA). 1990. *New Source Review Workshop Manual – Draft*. Office of Air Quality Planning and Standards, Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1992. Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised, EPA-454/R-92-019. October.

U.S. Environmental Protection Agency (EPA). 1995. On-Site Meteorological Program Guidance for Regulatory Model Applications, EPA-450/4-87-013. August.

U.S. Environmental Protection Agency (EPA). 2000. Compilation of Emission Factors. AP-42. Revised July.

U.S. Environmental Protection Agency (EPA). 2004. User's Guide for the AERMOD Meteorological Preprocessor (AERMET), EPA-454/B-03-002, November.

U.S. Environmental Protection Agency (EPA). 2005. AERMOD Implementation Guide, www.epa.gov/scram001/17thconf/aermod. September 17.

U.S. Environmental Protection Agency (EPA). 2005. 40 CFR Part 51, Appendix W. *Guideline on Air Quality Models*. Last update November 9, 2005.