Throughout this Application, all references to Federal Power, Federal Power Avenal, LLC, and Federal Power Avenal refer to Avenal Power Center, LLC.

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6.2 AIR QUALITY

This section describes existing air quality conditions, maximum potential impacts from the Avenal Energy Project (Project), and design features and mitigation measures that keep these impacts below thresholds of significance. The Project will use combined-cycle combustion gas turbine technology to generate electricity using a minimum amount of fuel, generating minimum air emissions, and minimizing potential effects on ambient air quality.

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

- Reduced air emissions by using clean-burning natural gas as fuel;
- Reduced nitrogen oxides (NOx) emissions through the use of selective catalytic reduction (SCR) control systems and dry low-NOx combustors on the turbines;
- Reduced carbon monoxide (CO) and non-criteria pollutant[1] emissions through use of an oxidation catalyst control system; and
- Reduced ground-level concentrations of exhaust constituents through use of appropriately sized stack height.

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 also addressed in Section 6.16 (Public Health).

Section 6.2.1 presents the air quality setting, including geography, topography, climate, and meteorology. Section 6.2.2 provides an overview of air quality standards and health effects. Section 6.2.3 discusses the criteria pollutants and existing air quality in the vicinity of the Project. The affected environment is discussed in Section 6.2.4, and air quality regulatory agencies relevant to the Project are identified; the laws, ordinances, regulations, and standards (LORS) that can affect the Project and Project conformance are also identified in Section 6.2.4. Section 6.2.5 discusses the environmental consequences of air emissions from the Project and presents an overview of approaches for estimating facility impacts, modeling, and analysis. The health risk assessment (HRA), construction impacts analysis, and analysis of Class I area air quality-related values, including visibility, are also discussed. Section 6.2.6 discusses

[1] Non-criteria pollutants are synonymous with toxic air contaminants (TACs).

compliance with LORS applicable to the Project. Cumulative impact analysis is discussed in Section 6.2.7. Mitigation for Project air quality impacts is discussed in Section 6.2.8. A list of references used in preparing the section is provided in Section 6.2.9.

6.2.1 AIR QUALITY SETTING

The geography of the potential site, elevations of the surrounding landscape, long-term climatic characteristics, and short-term weather variations all have important effects on the resulting ground-level pollutant concentrations that result from proposed project's air emissions. The effects of the land and atmospheric variables are discussed separately.

6.2.1.1 Geography and Topography

The Project will be located in the northeast corner of the City of Avenal, on industrial-zoned lands between the San Luis Canal and the Avenal Cutoff Road, six miles northeast of the residential and business districts of the City of Avenal in Kings County (see Figures 1.5-1 and 1.5-2). The Site is approximately two miles northeast of the Kettleman compressor station, and two miles east of Interstate 5 (see Figure 1.5-3). The nearest residences are over a mile from the Site (see Figure 6.16-2).

The site is gently sloping, at an elevation of approximately 340 feet above sea level. The terrain is relatively featureless on all sides of the site (see Figure 1.5-4). The Kettleman Hills lie approximately three miles southwest of the Project Site.

6.2.1.2 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 semipermanent 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 semipermanent 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. Precipitation rarely 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. The average annual rainfall at the site is approximately 7 inches, of which approximately 70% falls in the four months of December through March. Temperature, winds, and rainfall are more variable during the fall and winter months, but also stagnant conditions occur more frequently than during summer. (Climates of the States – California, U.S. Department of Commerce, Weather Bureau, 1959.)

Wind and mixing height are two key meteorological parameters that govern the potential for air pollution problems. The predominant winds in California are shown in Figures 6.2-1 through 6.2-4. (The Uses of Meteorological Data in Large-Scale Air Pollution Surveys, Stanford Research Institute, 1958). As the figures indicate, winds in California are generally light and easterly in the winter, but strong and westerly in the spring, summer, and fall.

Wind patterns in the general area of the project site are presented in Figures 6.2-5a through 5y, which show annual and quarterly wind roses for the Hanford, California monitoring station. Hanford is approximately 28 miles northeast of the site, and is the closest station for air quality and meteorological monitoring (discussed in more detail in Sections 6.2.3 and 6.2.5, respectively. Approximately half of all winds come from the northwest quadrant, and calm winds occur approximately one-quarter of the time.

Concerning mixing heights, inland areas, where marine influence is weak or nonexistent, experience strong ground-based inversions, which inhibit mixing and can result in high pollutant concentrations. An example case available from the central part of the San Joaquin Valley is Fresno. Smith, et al (1984), reported that at Fresno, 50th percentile morning mixing heights for the period 1979-80 were 115-150 meters (approximately 375-495 feet) in the fall and winter, 230 meters (755 feet) in the spring, and 175 meters (575 feet) in the summer. Such low morning mixing heights trap pollutants, at least during the morning. The 50th percentile afternoon mixing

heights, however, were unlimited in spring and summer, 1135 meters (3,725 feet) in the fall, and 630 meters (2,065 feet) in the winter. Such mixing heights provide generally favorable conditions for the dispersion of pollutants.

6.2.2 OVERVIEW OF AIR QUALITY STANDARDS

The U.S. Environmental Protection Agency (USEPA) has established national ambient air quality standards (NAAQS) for criteria pollutants, which are ozone, nitrogen dioxide (NO_2), CO, sulfur dioxide (SO_2), particulate matter with nominal aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with nominal aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. 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 California Air Resources Board (ARB) has established California ambient air quality standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, $PM_{2.5}$, airborne lead, hydrogen sulfide, vinyl chloride, and visibility-reducing particles 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.

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 (i.e., 1 hour, 3 hours), or to a relatively lower average concentration over a longer period (i.e., 8 hours, 24 hours, or 1 year). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 6.2-1 presents the NAAQS and California ambient air quality standards for the criteria pollutants. The California standards are generally set at concentrations lower than the federal standards.

USEPA's NAAQS for ozone is an eight-hour average standard of 0.08 ppm. Compliance with this standard is based on the three-year average of the annual 4th-highest daily maximum eight-hour average concentration measured at each monitor within an area.

Compliance with the current 24-hour PM_{10} standard of 150 μg/m^3 is based on the 99th percentile of 24-hour concentrations at each monitor within an area. There are two federal $PM_{2.5}$ NAAQS: a standard of 15 μg/m^3, based on the three-year average of annual arithmetic means from single or multiple monitors (as available); and a standard of 35 μg/m^3, based on the three-year average of the 98th percentile of 24-hour average concentrations at each monitor within an area.

TABLE 6.2-1
AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California	National
Ozone	1 hour 8 hours	0.09 ppm (180 μg/m^3) 0.07 ppm (137 μg/m^3)	 0.08 ppm (157 μg/m^3) [a]
Carbon Monoxide	8 hours 1 hour	9.0 ppm (10 mg/m3) 20 ppm (23 mg/m3)	9 ppm (10 mg/m3) 35 ppm (40 mg/m3)
Nitrogen Dioxide	Annual Average 1 hour	0.03 ppm (56 μg/m^3) 0.25 ppm (470 μg/m^3) [b]	0.053 ppm (100 μg/m^3) -
Sulfur Dioxide	Annual Average 24 hours 3 hours 1 hour	- 0.04 ppm (105 μg/m^3) (105 μg/m^3) - 0.25 ppm (655 μg/m^3)	80 μg/m^3 (0.030 ppm) 365 μg/m^3 (0.14 ppm) 1300 [c] μg/m^3 (0.5 ppm) -
Suspended Particulate Matter (10 Micron)	Annual Arithmetic Mean 24 hours	20 μg/m^3 50 μg/m^3	- 150 μg/m^3
Suspended Particulate Matter (2.5 Micron)	Annual Arithmetic Mean 24 hours	12 μg/m^3 -	15 μg/m^3 (3-year average) 35 μg/m^3 [d]
Sulfates	24 hours	25 μg/m^3	-
Lead	30 days Calendar Quarter	1.5 μg/m^3 -	- 1.5 μg/m^3
Hydrogen Sulfide	1-hour	0.03 ppm (42 μg/m^3)	-
Vinyl Chloride	24-hour	0.01 ppm (26 μg/m^3)	-
Visibility Reducing Particles	8-hour (10am to 6pm 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.	-

[a] Three-year average of annual 4th-highest daily maximum
[b] The replacement standard of 0.18 ppm (338 μg/m^3) will become officially effective upon action of the Office of Administrative Law.
[c] This a national secondary standard, which is designed to protect public welfare.
[d] 3-year average of 98th percentiles

The state annual PM_{10} standard is 20 μg/m^3; the state $PM_{2.5}$ standard is 12 μg/m^3 on an annual average basis. The current state 8-hour ozone standard is 0.070 ppm. Finally, on February 22,

2007, the ARB approved a new 1-hour NO_2 standard of 0.18 ppm; final approval of this new standard by the Office of Administrative Law is currently pending.

6.2.3 EXISTING AIR QUALITY

All ambient air quality data are taken from data published by ARB[2] and the USEPA[3] . Ambient concentrations of ozone, NO_2, and PM_{10} are recorded at a monitoring station in Hanford, approximately 28 miles northeast of the Project site. CO and NO_2 are monitored in Visalia, about 44 miles northeast of the Site. PM_{10} and $PM_{2.5}$ are recorded in Corcoran, about 27 miles east of the site. The nearest SO_2 monitoring station is in Sacramento, and ambient lead data are available for Fresno. The Visalia and Bakersfield monitoring stations are operated by the ARB; the Hanford and Corcoran stations by the San Joaquin Valley Air Pollution Control District (SJVAPCD); and the Sacramento station by the Sacramento Metropolitan Air Quality Management District (SMAQMD). The agencies placed the monitoring stations at sites that were judged to be representative of the areas surrounding them. The distances of the monitoring stations from the Project are such that ambient air quality measurements recorded at the monitoring stations are believed to represent area-wide ambient conditions rather than the localized impacts of any particular facility.

6.2.3.1 Ozone

Ozone is an end product of complex reactions between volatile organic compounds (VOC) and NOx in the presence of intense ultraviolet radiation. VOC and NOx 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 Hanford station are usually recorded during the summer months. Table 6.2-2 shows the annual maximum hourly ozone levels recorded at this monitoring station during the period 1997-2006 as well as the number of days in which the state and federal standards were exceeded. The data show that during the last half of the 1990s the state ozone air quality standard was exceeded about one-tenth of the days in the year. The trend since 2000 has been generally downward.

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[2] ARB. Air Quality Data Statistics, http://www.arb.ca.gov/adam/welcome.html.
[3] USEPA. Air Trends, http://www.epa.gov/airtrends/.

The long-term trends of maximum one-hour ozone readings and violations of the state standard are shown in Figures 6.2-6 and 6.2-7 for the Hanford station. The figures indicate that maximum

TABLE 6.2-2
OZONE LEVELS IN HANFORD, 1997-2006 (ppm)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 1-Hour Average	0.13	0.14	0.14	0.12	0.13	0.13	0.12	0.12	0.12	0.127
Highest 8-Hour Average	0.106	0.113	0.111	0.110	0.107	0.105	0.100	0.094	0.098	0.101
3-year arithmetic mean of 4th Highest 8-hour Average	0,097	0,105	0.099	0.102	0.098	0.099	0.095	0.093	0.088	0.086
Number of Days Exceeding:										
State Standard (0.09 ppm, 1-hour)	23	27	28	43	21	29	19	7	6	7
Federal Standard (0.08 ppm, 3-year average of annual 4th-highest daily maximum))	26	31	25	51	18	27	15	9	4	4

Sources: ARB. California Air Quality Data, http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/Branch. The ARB only provides data on the number of days exceeding the old California 1-hour standard instead of the new California 8-hour standard.

hourly ozone concentrations reach a level about 30% above the state standard. Figure 6.2-7a shows the downward long-term trend since 1997 of the three-year average 4th-highest 8-hour ozone level, which is the basis of the national 8-hour ozone standard. The District is not yet in attainment of the state and federal ozone air quality standards.

6.2.3.2 Nitrogen Dioxide

NO_2 is formed primarily from reactions in the atmosphere 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 6.2-3 shows the maximum one-hour NO_2 levels recorded in Hanford (Kings County) between 1997 and 2006. Annual average levels at each site for those years are also presented. Concentrations are very low. During the period shown, there has not been a single violation of

either the current state one-hour standard of 0.25 ppm or the NAAQS (0.053 ppm, annual average), or the soon to be officially updated one-hour standard.[4] Figure 6.2-8 shows the slightly

TABLE 6.2-3
NITROGEN DIOXIDE LEVELS IN THE PROJECT AREA, 1997-2006 (ppm)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 1-Hour Average										
Hanford	0.080	0.086	0.086	0.072	0.096	0.067	0.076	0.069	0.072	0.073
Visalia	0.095	0.081	0.092	0.079	0.075	0.095	0.087	0.078	0.069	0.063
Annual Average (NAAQS = 0.053 ppm)										
Hanford	0.014	0.014	0.016	0.014	--	0.014	0.013	0.012	0.012	0.012
Visalia	0.019	0.017	0.021	0.018	0.018	0.019	0.018	0.016	0.016	0.014
Number of Days Exceeding:										
State Standard (0.25 [a] ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0

Sources: ARB. California Air Quality Data, http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/Branch
[a] The replacement standard of 0.18 ppm (338 µg/m^3) will become officially effective upon action of the Office of Administrative Law.

downward long-term trend of maximum one-hour NO_2 levels from 1997 through 2006. These levels remain well below half the current, or soon to be officially updated one-hour, state standards. Figure 6.2-8a shows the slightly downward long-term trend of annual average NO_2 levels from 1997 through 2006. These levels remain well below half the state standard of 0.030 ppm.

6.2.3.3 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% 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 air quality planning, the San Joaquin Valley is classified as being in attainment of both national and state ambient standards for carbon monoxide.

[4] New state standards of 0.18 ppm for one-hour and 0.030 ppm annual arithmetic mean are awaiting approval by the California Office of Administrative Law to become official.

Table 6.2-4 shows the California and federal air quality standards for CO, and the maximum one- and eight-hour average levels recorded in Visalia during the period 1997-2006. Trends of maximum eight-hour and one-hour average CO levels are shown in Figures 6.2-9 and 6.2-10, respectively, which show that maximum ambient CO levels at Visalia have been below the state standards for many years, and continue to gradually decline. CO levels are not monitored at the Hanford site.

TABLE 6.2-4
CARBON MONOXIDE LEVELS IN VISALIA, 1997-2006 (ppm)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 8-hour average	4.14	3.79	4.11	4.23	3.68	2.85	3.03	2.24	2.61	*
Highest 1-hour average	7.3	7.4	2.9	5.9	5.7	4.2	4.7	3.7	3.8	
Number of days exceeding:										
State Standard (9 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	
State Standard (20 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	
Federal Standard (9 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	
Federal Standard (35 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	

* Insufficient data.
Source: ARB. California Air Quality Data, http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/Branch.

6.2.3.4 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 6.2-5 presents the state air quality standards for SO_2 and the maximum levels recorded in Bakersfield or Sacramento during the period 1997-2006.[5] The federal annual average standard is 0.03 ppm; during the period shown, the annual average SO_2 levels at both sites have been well under the federal standard. The state 24-hour average standard is 0.04 ppm, which was not exceeded in Bakersfield or Sacramento during the tabulated 10-year period. Figure 6.2-11 shows

[5] SO_2 was not sufficiently monitored in Bakersfield during 1998 and not monitored at all after 2001.

that maximum one-hour SO_2 levels in Sacramento and Bakersfield were less than one-fifth of the state standard during the entire 10-year period.

TABLE 6.2-5
SULFUR DIOXIDE LEVELS, 1997-2006 (ppm)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 1-Hour Average										
Bakersfield	0.01	--	0.01	0.02	*	*	*	*	*	*
Sacramento	0.038	0.029	0.026	0.023	0.031	0.017	0.013	0.008	0.018	*
Highest 24-Hour Average										
Bakersfield	0.004	--	0.006	0.011	0.005	*	*	*	*	*
Sacramento	0.004	0.005	0.004	0.005	0.017	0.005	0.003	0.003	0.003	0.002
Annual Average, All Hours										
Bakersfield	0.002	--	0.003	0.003	0.002	*	*	*	*	*
Sacramento	0.001	0.001	0.001	0.001	0.002	0.001	0.001	0.001	0.001	0.001
Number of Days Exceeding:										
State Standard (0.25 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
State Standard (0.04 ppm, 24-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard (0.5 ppm, 3-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard (0.14 ppm, 24-hour)	0	0	0	0	0	0	0	0	0	0

* Insufficient data.
Sources: ARB. California Air Quality Data, http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/Branch. Also, http://www.arb.ca.gov/aqd/aqdcd/aqdcddld.htm

6.2.3.5 Particulate Sulfates

Particulate sulfates are the product of further oxidation of SO_2. Elevated levels can also be due to natural causes. The San Joaquin Valley Air Basin is in attainment of the state standard for sulfates. There is no federal standard for sulfates.

Table 6.2-6 shows the California air quality standard for particulate sulfate and the maximum 24-hour average levels recorded in Bakersfield (the closest sulfate-monitoring site) from 1990 through 1997, the last year for which sulfate data are available). The trend of maximum 24-hour average sulfates over this period is plotted in Figure 6.2-12. Over the period shown, maximum levels generally declined to about 20%-30% of the state standard.

TABLE 6.2-6
PARTICULATE SULFATE LEVELS IN BAKERSFIELD, 1990-1997 (μg/m^3)

	1990	1991	1992	1993	1994	1995	1996	1997
Maximum 24-hour Average	11.9	9.7	9.2	9.5	15.0	7.5	7.4	5.6
Number of Days Exceeding:								
State Standard (25 μg/m^3, 24-hour)	0	0	0	0	0	0	0	0

Source: ARB. California Air Quality Data, Annual Summary.

6.2.3.6 Particulate (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; and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides. In 1984, the ARB adopted standards for respirable/inhalable particulates (particles with nominal aerodynamic diameter less than or equal to 10 microns, PM_{10}), and phased out the total suspended particulate (TSP) standards that had previously been in effect. In 1987, USEPA also replaced national TSP standards with PM_{10} standards. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of respirable particulates related to human health. In 2002, ARB lowered the annual limit from 30 to 20 μg/m^3.

Fine particulate (particles with nominal aerodynamic diameter less than or equal to 2.5 microns, $PM_{2.5}$) standards were promulgated by the federal government in 1997 and by California in 2002 because research indicated that the smaller size fine particulate caused more serious adverse health effects than the larger size respirable particulate. For air quality planning purposes, the San Joaquin Valley Air Basin is considered to be in nonattainment of both federal and state $PM_{2.5}$ standards, but on October 17, 2006, USEPA determined that the San Joaquin Valley Air Basin had attained the federal PM_{10} air quality standard.

Table 6.2-7 shows the federal and state air quality standards for PM_{10}, maximum levels recorded at monitoring stations in Kings County during 1997-2006, and geometric and arithmetic annual averages for the same period.[6] Maximum 24-hour PM_{10} levels continue to exceed the state standard many times per year. Annual average PM_{10} levels at both monitoring sites remain generally above the state standard. The 24-hour average federal standard has been achieved since 2003 at the Hanford monitoring station.

[6] The geometric mean is the *n*th root of the product of *n* observations. The arithmetic annual average is simply the mean of all observations. California shifted from use of the geometric mean to use of arithmetic mean in 2002.

Caltrans operated a PM_{10} monitoring station in Kettleman City, approximately 8 miles southeast of the Project site, between 1993 and 1996. More recent PM_{10} data are not available from that station. However, the limited data from this station near the Project site show that 24-hour PM_{10} concentrations there were always lower than the peak 24-hour concentrations monitored at the other stations and often lower than the concentrations monitored elsewhere in the county. Annual concentrations monitored at Kettleman City were always lower than the concentrations

TABLE 6.2-7
PM_{10} LEVELS IN KINGS COUNTY, 1997-2006 (µg/m^3)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average										
Hanford (S. Irwin St)	143	146	143	119	185	161	140	123	117	142
Corcoran (Patterson Ave)	199	128	174	137	165	168	150	217	131	304
Annual Arithmetic Mean (State Standard = 20 µg/m^3)[a]										
Hanford (S. Irwin St)	46.2	39.2	53.4	43.9	57.4	53.5	46.7	43.1	40.3	46.3
Corcoran (Patterson Ave)	48.1	38.5	52.2	46.3	47.1	51.9	48.1	42.2	41.1	44.4
Number of Days Exceeding: [b]										
State Standard (50 µg/m^3, 24-hour)	17	15	17	18	27	28	25	17	18	20
Federal Standard (150 µg/m^3, 24-hour)	0	0	0	0	2	1	0	0	0	0
Maximum Expected Violation Days: [b,c]										
State Standard (50 µg/m^3, 24-hour)	102	90	102	99	--	171.8	149	101	110	125
Federal Standard (150 µg/m^3, 24-hour)	0	0	0	0	14.1	6.1	0	0	0	0

Source: ARB. California Air Quality Data, Annual Summary,
Notes:
[a] State standard was a geometric mean of 30 µg/m^3 until 2002.
[b] Based on readings every six days. Shown for Hanford station.
[c] Based on multiplying exceedance readings by a factor of six due to readings taken only once per six days. The actual number of violation days is expected to be less since some of the days readings not taken will be within the standards.

monitored elsewhere in the county. Monitored concentrations were higher at Corcoran than at Hanford for the 24-hour averaging period with the exception of 1998 and 2001. The extremely high value of 304 µg/m^3 at Corcoran during 2006 was most likely associated with an unusual event (e.g., high wind and blowing dust event).

The trends of maximum 24-hour average PM_{10} levels at Hanford and Corcoran are plotted in Figure 6.2-13, and the trend of violations of the state 24-hour standard of 50 µg/m^3 is plotted in Figure 6.2-14. Note that since PM_{10} is measured only once every six days, expected violation days are six times the number of measured violations.

Table 6.2-8 presents the maximum 24-hour average $PM_{2.5}$ concentration and annual arithmetic mean reported by ARB from the Corcoran monitoring station, and the three-year average levels of those readings. Historical trends of the maximum and 98th percentile 24-hour average concentrations are shown in Figure 6.2-15. The data from the Corcoran monitor indicate that 98th percentile 24-hour average $PM_{2.5}$ concentration levels have been erratic and above the Federal standard of 35 $\mu g/m^3$. The 3-year average of annual arithmetic means has been above the NAAQS for this pollutant (15 µg/m3) at least since 2002.

TABLE 6.2-8
$PM_{2.5}$ LEVELS IN CORCORAN, 1997-2006 ($\mu g/m^3$)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Highest 24-Hour Average	*	*	53.0	76.0	123.2	90.7	55.1	61.0	92.5	74.2
98th Percentile 24-Hour Average Concentration	*	*	*	*	89.5	65.1	42.2	49.4	74.5	50.1
Three-Year Average – 98th Percentile of 24-Hour Average Concentrations (Federal Standard = 35$\mu g/m^3$)	*	*	*	*	*	*	66	52	55	58
Annual Arithmetic Mean	*	*	*	16.4	19.2	21.5	16.2	17.4	17.5	16.9
Three-Year Average of Annual Arithmetic Mean (State Standard = 12 $\mu g/m^3$; Federal Standard = 15$\mu g/m^3$)	*	*	*	*	*	19	19	18	17	17`

* Insufficient data.
Source: ARB. California Air Quality Data, http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/Branch.
Note: The $PM_{2.5}$ data are derived from the dichotomous sampler and not from a Federal Reference Method $PM_{2.5}$ sampler. ARB indicates that this information should not be used for a regulatory comparison to the national $PM_{2.5}$ standards.

6.2.3.7 Airborne Lead

The majority of lead in the air results from the combustion of fuels that contain lead. Until 25 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 deactivated by the exhaust products of leaded gasoline. Thus, unleaded gasoline became the required fuel for an increasing fraction of new vehicles, and the phasing 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 6.2-9 lists the state air quality standard for airborne lead and the levels recorded in the Central Valley between 1996 and 2003 (no data are available for 2004 through 2006). Quarterly lead data are reported by USEPA in its AIRS database for Fresno and Bakersfield stations between

TABLE 6.2-9
AIRBORNE LEAD LEVELS IN THE CENTRAL VALLEY, 1996-2003 (µg/m^3)

	1996	1997	1998	1999	2000	2001	2002	2003
Highest Quarterly Average								
Fresno [1]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Bakersfield [2]	0.01	0.01	0.02	0.01	0.01	0.01	0.01	*

* Insufficient data.
[1] USEPA. http://www.epa.gov/cgi-bin/broker?_service=data&_server=shire.epa.gov&_port=4072&_sessionid=/NRXy6xZmoD&_PROGRAM=dataprog.siteplot_06.sas&_debug=0&site=060190008&poll= 12128
[2] USEPA. http://www.epa.gov/cgi-bin/broker?_service=data&_server=shire.epa.gov&_port=4072&_sessionid=/NRXy6xZmoD&_PROGRAM=dataprog.siteplot_06.sas&_debug=0&site=060290014&poll= 12128

1995 and 2003.[7] The trend of quarterly airborne lead levels from 1996 through 2003 is plotted in Figure 6.2-16, which shows that concentrations remain almost immeasurable.

6.2.4 REGULATORY ENVIRONMENT

The USEPA 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 USEPA Region 9, which has its offices in San Francisco. Region 9 is responsible for the local administration of USEPA programs for California, Arizona, Nevada, Hawaii, and certain Pacific trust territories. USEPA'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).

[7] EPA does not report monthly average readings because the federal standard is on a quarterly basis. The NAAQS for lead is numerically the same as the state standard (1.5 µg/m^3), but because the averaging period is quarterly, not monthly, the NAAQS is less stringent.

The ARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. ARB'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 standard;
- 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. The other agencies having permitting authority for this Project are shown in Table 6.2-10. The applicable federal laws,

TABLE 6.2-10
AIR QUALITY AGENCIES

Agency	Authority	Contact
USEPA Region 9	PSD permit issuance, enforcement	Gerardo Rios, Chief, Permits Office USEPA Region 9 75 Hawthorne Street San Francisco, CA 94105 (415) 744-1259
ARB	Regulatory oversight	Mike Tollstrup, Chief Project Assessment Branch California Air Resources Board 2020 L Street Sacramento, CA 95814 (916) 322-6026
SJVAPCD	Permit issuance, enforcement, Acid Rain Program	David Warner Director of Permit Services 1990 E. Gettysburg Avenue Fresno, CA 93726-0244 (559) 230-6000

ordinances, regulations, and standards (LORS) and compliance with these requirements are discussed in more detail in the following sections. Updated Applications for a Determination of Compliance and a Prevention of Significant Deterioration Permit (PSD) are being filed with the SJVAPCD and the USEPA, respectively, at approximately the same time as the Application for Certification (AFC) is being filed with the California Energy Commission (CEC or Commission).

6.2.4.1 Laws, Ordinances, Regulations, And Standards

Requirements of federal, state, and local jurisdictions are discussed in the following Sections 6.2.4.1.1, 6.2.4.1.2, and 6.2.4.1.3, respectively. Compliance with each of these requirements is addressed in Section 6.2.6.

6.2.4.1.1 *Federal*

The USEPA implements and enforces the requirements of many of the federal environmental laws. The federal Clean Air Act, as most recently amended in 1990, provides USEPA with the legal authority to regulate air pollution from stationary sources such as the Project. USEPA 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 USEPA has established national ambient air quality standards (NAAQS)) 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 turbines and fired waste-heat recovery boilers;
- 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 hence would apply to the Project's auxiliary boiler;
- The Standards of Performance for Stationary Spark Ignition Internal Combustion Engines would apply to the natural gas-fueled emergency standby generator engine because this engine is located at an area (non-major) source of HAP emissions.[8] The applicable emission standard would be 1.0 g/hp-hr of non-methane hydrocarbons (NMHC); and
- The Standards of Performance for Stationary Compression Ignition Internal Combustion Engines[9] would apply to the Diesel-fueled emergency standby fire water pump engine.

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

Administering Agency: SJVAPCD, with USEPA Region 9 and ARB 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 USEPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in

[8] Federal Register, Volume 71, No. 122, pp. 39394-36395, June 26, 2006 and pp. 33804-33855, June 12, 2006..
[9] Federal Register, Volume 71, No. 132, pp. 39154-39185, July 11, 2006.

specific source categories.[10] These standards are implemented at the local level with federal oversight. Only the NESHAPs for combustion turbines, which limit formaldehyde emissions from turbines, and the NESHAPs for Stationary Reciprocating Internal Combustion Engines (RICE)[11] are potentially applicable to a new power plant project. However, as discussed further below, these two NESHAPs are 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 USEPA 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
- Protection of Class I areas
- Growth, visibility, soils, and vegetation impacts

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[10] 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.

[11] USEPA. National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE), Final Rule, 69FR33473, June 15, 2004.

The project will result in emissions exceeding the applicable PSD thresholds for NO_2, CO, and PM_{10} emitted from the fossil fuel-fired steam-electric plant category[12] listed in the federal PSD regulations (40CFR52.21), and, therefore, the Project is subject to PSD review. As the SJVAPCD does not have delegation for the PSD program, a separate PSD application must be filed with the USEPA.

Air Quality Monitoring

At its discretion, USEPA 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. USEPA defines BACT as an emissions limitation, called the Lowest Achievable Emission Rate (LAER) 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/LAER must be as stringent as any emission limit required by an applicable NSPS or NESHAP. BACT/LAER 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 6.2-11.

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[12] Fossil fuel-fired steam-electric plant with heat input greater than 250 MMBtu/hour.

TABLE 6.2-11
PSD CLASS II INCREMENTS[a]

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

Notes:
[a] On October 17, 2006, the USEPA designated the San Joaquin Valley Air Basin attainment for PM_{10}. Therefore, PSD requirements are not applicable for PM_{10}.
[b] Not to be exceeded
[c] 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 would 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: USEPA, 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. This program is implemented at the local level with USEPA oversight.
Administering Agency: SJVAPCD, with USEPA 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 USEPA 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 USEPA as requiring a Title V permit. These requirements are implemented at the local level with federal oversight.
Administering Agency: SJVAPCD, with USEPA Region 9 oversight.

6.2.4.1.2 *State*

The ARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. The ARB'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 ARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California Health & Safety Code (H&SC):

- State Implementation Plan
- California Clean Air Act
- Toxic Air Contaminant Program
- Airborne Toxic Control Measure for Stationary Compression-Ignition Engines
- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and ARB Memorandum of Understanding

State Implementation Plan

Authority: Health & Safety Code (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 ARB 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 ARB and USEPA 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 ARB 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 ARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants. The ARB 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[13] as toxic air contaminants. The ARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to

[13] The USEPA 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.

reduce the emissions. Air Toxic Control Measures that are applicable to the Project are discussed further below.

Airborne Toxic Control Measure for Stationary Compression-Ignition Engines
Authority: Title 17, California Code of Regulations, §93115
Purpose: The purpose of the airborne toxic control measure (ATCM) is to reduce Diesel particulate matter (DPM) and criteria pollutant emissions from stationary Diesel-fueled compression ignition engines. The ATCM applies to stationary compression-ignition engines with a rating greater than 50 brake horsepower. The ATCM requires the use of ARB-certified Diesel fuel or equivalent, and limits emissions from, and operations of, compression ignition engines.
Administering Agency: SJVAPCD and ARB

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 ARB

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[14] 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

[14] Commonly known as AB2588.

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 ARB oversight.

CEC and ARB 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)
Purpose: Establishes requirements in the Commission'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,[15] and the ARB has proposed draft regulations to limit GHG emissions from electric power plants and other specific source categories[16]. In addition, the ARB has issued draft guidance with recommended emission factors for calculating GHG emissions.[17]

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

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[15] 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).
[16] ARB. *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),* October19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm.
[17] ARB. *Attachments C to F, Supplemental Maerials 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),* October19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

- 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 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"[18].

On January 25, 2007, the PUC 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.[19]

Administering Agencies: ARB and CEC.

6.2.4.1.3 *Local*

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

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[18] Appendix B (g) (8) (E) of the CEC siting regulations.

[19] 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 CO2 per MW-hr originated in PUC Interim Decision 07-01-039.

measures and new source review requirements are discussed with individual SJVAPCD Rules and Regulations.
Administering Agency: SJVAPCD, with ARB 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 USEPA Region 9 and ARB oversight.

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 Commission.

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 6.2-12.

TABLE 6.2-12
DISTRICT BACT EMISSION THRESHOLDS

Pollutant	Threshold
PM	2 lb/day
NOx	2 lb/day
SO_2	2 lb/day
VOC	2 lb/day
CO	100 tpy

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 USEPA 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 6.2-13 must offset all emissions increases at a ratio that varies according to the distance between the facility and the source of the offsets.

TABLE 6.2-13
DISTRICT OFFSET EMISSION THRESHOLDS

Pollutant	Threshold, lb/yr
NOx	20,000
SO_2	54,730
CO	200,000 [a]
VOC	20,000
PM	29,200

[a] 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.

Commission Review

Rule 2201, Section 5.8 establishes a procedure for coordinating SJVAPCD review of power plant projects with the Commission 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 Commission. A permit to operate is issued following the Commission'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 NOx, and must monitor SO_2, NOx, 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.[20] 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 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:

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

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, and hence, it is applicable to the Project. Subpart KKKK limits NOx 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 NOx 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 hence, would apply to the Project's auxiliary boiler.

The Standards of Performance for Stationary Spark Ignition Internal Combustion Engines would apply to the natural gas-fueled emergency standby generator engine because this engine is located at an area (non-major) source of HAP emissions.[21] The applicable emission standard would be 1.0 g/hp-hr of non-methane hydrocarbons (NMHC).

The Standards of Performance for Stationary Compression Ignition Internal Combustion Engines[22] would apply to the Diesel-fueled emergency standby fire water pump engine. For the maximum engine power of 288 hp and an assumed purchase in the year operation would commence, 2012, the emission standards would be the following: 3.0 g/hp-hr of NOx+NMHC and 0.15 g/hp-hr of particulate matter (PM).

Rule 4002 – National Emissions Standards for Hazardous Air Pollutants: This rule implements the federal NESHAPS regulations discussed above in Section 6.2.4.1.1. The combustion turbine NESHAP and Stationary Reciprocating Internal Combustion Engines (RICE) are 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.

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[21] Federal Register, Volume 71, No. 122, pp. 39394-36395, June 26, 2006 and pp. 33804-33855, June 12, 2006..
[22] Federal Register, Volume 71, No. 132, pp. 39154-39185, July 11, 2006.

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
- NOx as NO_2 to 140 pounds per hour

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

- Gas-fired NOx emissions to 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu)
- CO emissions to 400 ppmvd @ 3% O_2
- Requires installation of CEMs for NOx, CO and O_2

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

- Category H boiler (i.e., annual heat input between 9 and 30 billion Btu/year) gas-fired NOx 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 NOx 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
- Requires installation of CEMs for NOx, CO, and O_2

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

- Gas-fired NOx emissions to 90 ppmvd @ 3% O_2 (0.10 lb/MMBtu)
- CO emissions to 400 ppmvd @ 3% O_2
- Requires monitoring of any NOx control system

Rule 4701 (Internal Combustion Engines): The emergency standby generator and fire water pump engines are exempt from the requirements pursuant to rule Sections 4.2.1 (standby engines) and 4.2.2 (engines used exclusively for fire fighting services and flood control), except for the administrative requirements of Sections 6.1, 6.2.2, and 6.2.3.

Rule 4703 – Stationary Gas Turbines: Limits

- NOx (Tier 1) emissions from combined-cycle stationary gas turbines rated > 10 MW with SCR to (9/25)*Eff ppmvd @15% O_2 where Eff (%) = 3,412 Btu/kWh divided by actual heat rate (HHV[23])
- NOx (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 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 PM_{10} 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.

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[23] High heating value.

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.

In summary, air quality impact analysis will be applied to the above regulatory programs and regulated pollutants as shown in Table 6.2-14.

TABLE 6.2-14
AIR QUALITY IMPACT ANALYSIS SIGNIFICANCE THRESHOLDS

Air Quality Criteria	VOC [a]	NO_2	PM_{10}	$PM_{2.5}$	CO	SO_2
PSD Significant Impact Levels	NA [b]	√	√	NA	√	NA
PSD Monitoring Exemption Levels	NA	√	√		√	NA
Ambient Air Quality Standards (AAQS)	NA	√	√	√[c]	√	√
Class I and Class II Visibility		√	√			√
Impacts to Soils and Vegetation		√	√			√
Class I Area Deposition		√	√			√

Notes:
[a] VOC emissions are used as a surrogate for ozone impacts in the PSD review process; no ozone modeling will be carried out.
[b] Not applicable.
[c] USEPA guidance (71 FR 6727) provides that compliance with the federal $PM_{2.5}$ NAAQS should be evaluated using the PM_{10} NAAQS and not modeled directly.

All laws, ordinances, regulations and standards (LORS) applicable to the Project are summarized in Table 6.2-15.

TABLE 6.2-15
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections, Pages)
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 Parts 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.	USEPA	Issues PSD Permit for a Major Modification to an Existing Major Source.	Permit to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-17 and -18; Sec. 6.2.5, pp. 6.2-60 to 62; Sec. 6.2.6, pp. 6.2-64 to 65
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 USEPA oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-19, -24, -25
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NOx and SO_2 emissions.	SJVAPCD with USEPA oversight	Issues Acid Rain monitoring plan error report after review of application.	Meet compliance deadlines listed in regulations; no permit issued.	Sec. 6.2.4, pp. 6.2-26, -71, and -72
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD with USEPA oversight	Issues Title V permit after review of application.	Permit to be obtained prior to commencement of construction.	Sec. 6.2.4, pp. 6.2-26
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 USEPA oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-16, - 17 and -27
State					
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 ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Screening HRA submitted as part of AFC.	Sec. 6.2.4, pp. 6.2-22 and -23
California Public Resources Code §25523(a); 20 CCR §§1752, 2300-2309 (CEC & ARB Memorandum of Understanding)	Requires that Commission's decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	Commission	After Project review, issues Final Certification with conditions limiting emissions.	SJVAPCD approval of AFC, i.e., DOC, to be obtained prior to Commission approval.	Sec. 6.2.4 p. 6.2-23

TABLE 6.2-15
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections, Pages)
Local					
SJVPCD Rule 2201 (New and Modified Stationary Source Review)	NSR: Requires that pre-construction review be conducted for all proposed new or modified sources of air pollution, including BACT, emissions offsets, and air quality impact analysis.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-24 and -25, Sec. 6.2.5, pp. 6.2-35 through -62, Sec. 6.2.6, pp. 6.2-67 through -71.
SJVAPCD Rule 2520 (Federally Mandated Operating Permits)	Implements operating permits requirements of CAA Title V.	SJVAPCD with USEPA oversight	Issues Title V permit after review of application.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, p. 6.2-26,, Sec. 6.2.6, p. 6.2-71.
SJVAPCD Rule 2540 (Acid Rain Program)	Implements acid rain regulations of CAA Title IV.	SJVAPCD with USEPA oversight	Issues Title IV permit after review of application.	Application to be made within 12 months of start of facility operation.	Sec. 6.2.4, p. 6.2-26, Sec. 6.2.6, pp. 6.2-71 and -72
SJVAPCD Rule 4001 (New Source Performance Standards: 40 CFR 60, Subpart KKKK, Stationary Gas Turbines	Requires monitoring of fuel and other operating parameters; limits NOx and SO_2 and PM emissions; requires source testing, emissions monitoring, and recordkeeping.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-26 and -27; Sec. 6.2.6, p. 6.2-72
SJVAPCD Rule 4002 (National Emission Standards for Hazardous Air Pollutants)	Implements CAA NESHAPS regulations (40 CFR Part 63)	SJVAPCD with USEPA oversight	Issues Title IV permit after review of application.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, p. 6.2-27; Sec. 6.2.6, pp. 6.2-71 and -72.
SJVAPCD Rule 4101 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 1 for periods greater than 3 minutes in any hour.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained prior to commencement of operation.	Sec. 6.2.4, p. 6.2-28, and Sec. 6.2.6, p. 6.2-72
SJVAPCD Rule 4102 (Public Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-28; Sec. 6.2.6, p. 6.2-72
SJVAPCD Rule 4201 (Particulate Matter)	Limits PM emissions from stationary sources.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-28; Sec. 6.2.6, p. 6.2-72

TABLE 6.2-15
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections, Pages)
SJVAPCD Rule 4301 (Fuel Burning Equipment)	Limits PM_{10}, SOx and NOx emissions from auxiliary boiler.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-28; Sec. 6.2.6, p. 6.2-72 and -71
SJVAPCD Rule 4305 (Boilers, Steam Generators and Process Heaters Phase 2)	Limits NOx and CO emissions from auxiliary boiler, and requires CEMs.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-28; Sec. 6.2.6, p. 6.2-72
SJVAPCD Rule 4306 (Boilers, Steam Generators and Process Heaters Phase 3)	Limits NOx and CO emissions from auxiliary boiler, and requires CEMs.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-28; Sec. 6.2.6, p. 6.2-73
SJVAPCD Rule 4351 (Boilers, Steam Generators and Process Heaters Phase 1)	Limits NOx and CO emissions from auxiliary boiler, and requires monitoring of NOx control system.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-73
SJVAPCD Rule 4701 (Internal Combustion Engines – Phase 1)	Limits NOx, VOC and CO emissions from internal combustion engines.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, pp. 6.2-73 and -74
SJVAPCD Rule 4703 (Stationary Gas Turbines)	Limits NOx and CO emissions from the gas turbines.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 4801 (Sulfur Compounds Emissions)	Limits SO_2 emissions from stationary sources.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 4001 (New Source Performance Standards: 40 CFR 60, Subpart KKKK, Stationary Gas Turbines	Requires monitoring of fuel and other operating parameters; limits NOx and SO_2 and PM emissions; requires source testing, emissions monitoring, and recordkeeping.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-26 and -27; Sec. 6.2.6, p. 6.2-72
SJVAPCD Rule 8011 (Fugitive PM_{10} Prohibitions, General Requirements)	Sets forth definitions, applicability and administrative requirements for anthropogenic sources of PM_{10}	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 8021 (Fugitive PM_{10} Prohibitions, Construction, Demolition,	Limits fugitive dust emissions from construction, demolition, excavation, and related activities.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74

TABLE 6.2-15
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Sections, Pages)
Excavation, Extraction and other Earthmoving Activities)					
SJVAPCD Rule 8041 (Carryout and Trackout, Fugitive PM_{10} Prohibitions)	Limits fugitive dust emissions from construction carryout and trackout.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 8051 (Open Areas, Fugitive PM_{10} Prohibitions)	Limits fugitive dust emissions from disturbed portions of open areas.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 8061 (Paved and Unpaved Roads, Fugitive PM_{10} Prohibitions)	Limits fugitive dust emissions from paved and unpaved roads.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-74
SJVAPCD Rule 8071 (Unpaved Vehicle/Equipment Traffic Areas, Fugitive PM_{10} Prohibitions)	Limits fugitive dust emissions from unpaved vehicle/equipment traffic areas.	SJVAPCD with ARB oversight	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-29; Sec. 6.2.6, p. 6.2-75
SJVAPCD Risk Management Review Policy for Permitting New and Modified Sources	Requires demonstration that impacts of toxic substances from new or modified sources will not adversely affect public health	SJVAPCD	After Project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	Sec. 6.2.4, pp. 6.2-26

6.2.4.2.7 *Attainment Status*

Based on the measured existing air quality described in Section 6.2.3, the ambient air quality standards presented in Table 6.2-1, and the responsibilities of the EPA and the ARB discussed in Sections 6.2.4.1.1 and 6.2.4.1.2, respectively, the attainment status of the San Joaquin Valley Air Basin is shown in Table 6.2-16.

TABLE 6.2-16
AMBIENT AIR QUALITY STANDARD ATTAINMENT STATUS IN SAN JOAQUIN VALLEY AIR BASIN

Pollutant	Averaging Time	California	National
Ozone	1 hour	Nonattainment	No NAAQS
	8 hours	Nonattainment, serious	Nonattainment
Carbon Monoxide	8 hours	Attainment/ Unclassified	Attainment/ Unclassified
	1 hour	Attainment/ Unclassified	Attainment/ Unclassified
Nitrogen Dioxide	Annual Average	Attainment	Attainment/ Unclassified
	1 hour	Attainment	No NAAQS
Sulfur Dioxide	Annual Average	No CAAQS	Attainment/ Unclassified
	24 hours	Attainment/ Unclassified	Attainment/ Unclassified
	3 hours	No CAAQS	Attainment/ Unclassified
	1 hour	Attainment/ Unclassified	No NAAQS
Respirable Particulate Matter (10 Micron)	Annual Arithmetic Mean	Nonattainment	No NAAQS
	24 hours	Nonattainment	Attainment
Fine Particulate Matter (2.5 Micron)	Annual Arithmetic Mean	Nonattainment	Nonattainment
	24 hours	No CAAQS	Attainment[a]
Sulfates	24 hours	Attainment	No NAAQS
Lead	30 days	Attainment	No NAAQS
	Calendar Quarter	No CAAQS	No designation or classification
Hydrogen Sulfide	1-hour	Unclassified	No NAAQS
Vinyl Chloride	24-hour	Attainment	No NAAQS
Visibility Reducing Particles	8-hour (10am to 6pm PST)	Unclassified	No NAAQS

Notes:
[a] District has determined that attainment was achieved during 2004-2006, but EPA has not yet approved the change in status from nonattainment.

6.2.5 ENVIRONMENTAL CONSEQUENCES

The District, EPA, and CEC require an analysis of potential ambient air quality impacts for criteria pollutants (NO_2, CO, PM_{10}, and SO_2) and noncriteria pollutants during project operation, and the CEC requires the same for project construction. The analyses cover each phase of the proposed project. Section 6.2.5.1 gives an overview of the analytical approach. Section 6.2.5.2 presents the emissions for operation of the project, and Section 6.2.5.3 gives the ambient air quality impacts of operation. Section 6.2.5.4 gives the analysis for construction.

6.2.5.1 Overview of the Analytical Approach to Estimating Facility Impacts

The following sections describe the emission sources that have been evaluated, the results of the ambient impact analyses, and the evaluation of project compliance with the applicable air quality regulations, including the District's NSR requirements. These analyses are designed to confirm that the proposed project's design features lead to less-than–significant impacts even with the following conservative analysis assumptions and procedures: maximum allowable emission rates, project operating schedules that lead to maximum emissions, worst-case meteorological conditions, and adding the worst-observed existing air quality to the highest potential ground-level impact from modeling, even when all of these situations could not physically occur at the same time.

The emissions sources at the Project include two combustion turbines with HRSGs and duct burners, one steam turbine, an auxiliary boiler, a natural gas-fueled emergency standby generator engine, and a Diesel-fueled emergency fire water pump engine. The operational load of the turbines will range between 50 percent and 100 percent of their maximum rated output. Supplemental firing will be provided by the duct burners as needed to maintain required electricity and steam production rates. Inlet air chillers will be used to increase power output under warmer ambient conditions as well. The auxiliary boiler will be used to provide additional steam for facilitating startup of the turbines. Emission control systems will be fully operational during all operations except early commissioning tests, startups and shutdowns. Maximum annual emissions are based on expected maximum hours of operation at maximum firing rates, both with and without duct firing, and include the expected maximum number of startup hours that may occur in a year. Each turbine startup will result in higher transient emission rates until steady-state operation for the gas turbine and emission control systems is achieved.

Ambient air quality impact analyses for the site have been conducted to satisfy the USEPA, SJVAPCD, and Commission requirements for criteria pollutants (NO_2, CO, PM_{10}, $PM_{2.5}$ and SO_2), noncriteria pollutants, and construction impacts on a pollutant-specific basis. The following sections describe the emission sources that have been evaluated for the Project, the ambient impact analyses results, and the evaluation of facility compliance with the applicable air quality regulations, including SJVAPCD Rules 2010 (Permits Required) and 2201 (New and Modified Stationary Source Review Rule).

6.2.5.1.1 *Facility Emissions*

The Project will be a new stationary source under District rules. As discussed in Chapter 2, the new equipment will consist of two General Electric 7241 (FA) combustion turbines (or equivalent), rated at 180 MW (nominal net, at site design conditions); two HRSGs equipped with duct burners rated at 562 MMBtu/hr (HHV, maximum); a 300-MW (nominal) condensing steam turbine; one 25,000 lb/hr auxiliary boiler; and two inlet air chillers. Emergency equipment will include a 288 bhp Diesel-fueled standby fire water pump engine and a 550 kW standby natural gas-fired generator engine.

Each gas turbine will be equipped with dry low-NOx combustors and a selective catalytic reduction (SCR) system for NOx control. An oxidation catalyst will be used to reduce CO emissions. Particulate and VOC emission will be minimized through the use of natural gas as the fuel. Emissions control systems will operate full time except during the early part of startups and the later part of shutdowns. Specifications for the new gas turbines are summarized in Table 6.2-17.

TABLE 6.2-17
NEW GE 7FA COMBINED-CYCLE COMBUSTION TURBINE DESIGN SPECIFICATIONS

Manufacturer	General Electric
Model	7FA
Fuel	Natural gas
Design Ambient Temperature [a]	32 °F
Maximum Turbine Heat Input Rate	2,356.5 MMBtu/hr @ HHV (each turbine)
Maximum Turbine Power Generation Rate	180 MW (each turbine)
Stack Exhaust Temperature [a]	201°F (after HRSG)
Exhaust Flow Rate [a]	1,071,653 acfm (without duct firing)
Exhaust O_2 Concentration, dry volume [a]	13.78%
Exhaust CO_2 Concentration, dry volume [a]	4.08%
Exhaust Moisture Content, wet volume [a]	7.78%
Emission Controls	Dry Low-NOx Combustor and SCR (2.0 ppmvd NOx @ 15% O_2 and ammonia slip of 10 ppmvd@ 15% O_2); oxidation catalyst (4.0 ppmv CO); combustion controls (2.0/1.4 ppmv VOC @ 15% O_2, with and without duct firing)

Note:
[a] Low-temperature baseload operating scenario corresponds to maximum heat input rate.

Additional specifications for the turbines/HRSGs, the auxiliary boiler, and the emergency equipment are provided in Appendix 6.2-1, Tables 6.2-1.1 through 6.2-1.4. Natural gas will be the only fuel consumed by the turbines during plant operation. There will be no Diesel fuel firing at the Project except in the emergency standby fire water pump engine. Typical specifications for the natural gas fuel are shown in Table 6.2-18.

TABLE 6.2-18
NOMINAL FUEL PROPERTIES – NATURAL GAS

Component Analysis		Chemical Analysis	
Component	Average Concentration, Volume	Constituent	Percent by Weight
CH_4	95.96 %	C	72.93%
C_2H_6	1.95 %	H	23.99%
C_3H_8	0.24%	N	1.81%
C_4H_{10}	0.07%	O	1.28%
C_5H_{12}	0.02%	S	0.36 gr/100 scf[a]
C_6H_{14}	0.01%		
N_2	1.08 %	Higher Heating Value (HHV)	1013.3 Btu/scf[b] 22,961 Btu/lb
CO_2	0.67 %		
S	<0.00%		

Notes:
[a] This sulfur level is the annual average estimated high enough to conservatively calculate annual emissions. The natural gas tariff limit of 1.0 gr/100 scf is used to calculate short-term emissions.
[b] Standard cubic feet (scf) are based on conditions of 14.696 psia and 60°F.

Natural gas combustion results in the formation of NOx, SO_2, unburned hydrocarbons (volatile organic compounds, VOC), PM_{10}, and CO. Because natural gas is a clean burning fuel, there will be minimal formation of combustion PM_{10} and SO_2. The combustion turbines will be equipped with dry low-NOx combustors that minimize the formation of NOx and CO. To further reduce NOx and CO emissions, selective catalytic reduction (SCR) and oxidation catalyst control systems will be utilized, respectively. The duct burners and auxiliary boiler will also be equipped with low-NOx burners that minimize NOx formation.

Noncriteria pollutants will also be emitted by the facility, including ammonia (NH_3), which is used as a reactant by the SCR systems to control NOx. Emissions of all of the criteria and noncriteria pollutants have been characterized and quantified in this application.

Criteria Pollutant Emissions

The combustion turbine, duct burner, and auxiliary boiler emission rates have been estimated from vendor data, Project design criteria, and established emission calculation procedures. The emission rates for the combustion turbines alone, the combustion turbines with duct burners and power augmentation, and the auxiliary boiler alone are shown in Tables 6.2-19, 6.2-20, and 6.2-21, respectively.

TABLE 6.2-19
MAXIMUM POLLUTANT EMISSION RATES
EACH COMBUSTION TURBINE WITHOUT DUCT FIRING[a]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu (HHV)	lb/hr
NOx	2.0	0.0073	13.47
CO	4.0	0.0088	16.39
VOC	1.4	0.0018	3.28
PM_{10}/ $PM_{2.5}$[b]	-	0.0050	9.0
SO_2[c]	0.56	0.0028	5.24

Notes:
[a] Emission rates shown reflect the highest value with no duct firing at any operating load. For NOx, CO, and VOC, values exclude startups and shutdowns.
[b] 100 percent of particulate matter emissions assumed to be emitted as $PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.
[c] Based on maximum fuel sulfur content of 1.00 grain S/100 scf. Expected long-term (annual) fuel sulfur limit is 036 grains/100 scf.

TABLE 6.2-20
MAXIMUM POLLUTANT EMISSION RATES
EACH COMBUSTION TURBINE WITH DUCT FIRING

Pollutant	ppmvd @ 15% O_2	lb/MMBtu (HHV)	lb/hr
NOx	2.00,	0.0073	17.13
CO	4.00	0.0089	20.86
VOC	2.00	0.0025	5.96
PM_{10}/ $PM_{2.5}$[a]	-	0.0050	11.81
SO_2[b]	0.56	0.0028	6.65

Notes:
[a] 100 percent of particulate matter emissions assumed to be emitted as $PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.
[b] Based on maximum fuel sulfur content of 1.00 grain S/100 scf. Expected long-term (annual) fuel sulfur limit is 036 grains/100 scf.

TABLE 6.2-21
MAXIMUM POLLUTANT EMISSION RATES
AUXILIARY BOILER

Pollutant	ppmvd @ 3% O_2	lb/MMBtu (HHV)	lb/hr
NOx	9.0	0.011	0.41
CO	50.0	0.037	1.38
VOC	10.0	0.0042	0.16
PM_{10}/ $PM_{2.5}$[a]	N/A	0.005	0.19
SO_2[b]	0.56	0.0028	0.10

Notes:
[a] 100 percent of particulate matter emissions assumed to be emitted as $PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.
[b] Based on maximum fuel sulfur content of 1.00 grain S/100 scf. Expected long-term (annual) fuel sulfur limit is 036 grains/100 scf.

The maximum firing rates, daily and annual fuel consumption rates, and operating restrictions define the allowable operations that determine the maximum potential hourly, daily, and annual emissions for each pollutant.

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/start, maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

TABLE 6.2-24
EMISSIONS FROM NEW EQUIPMENT DURING NORMAL OPERATION YEAR[a]

	NOx	SO_2	CO	VOC	PM_{10}/ $PM_{2.5}$
Maximum Hourly Emissions, lb/hr					
Turbines and Duct Burners[b]	240	13.3	1,902	32	23.6
Auxiliary Boiler[c]	0.41	0.1	1.38	0.16	0.19
Emergency Generator Engine[d]	2.84	0.02	4.0	0.63	0.065
Diesel Fire Water Pump Engine[d]	2.16	0.003	0.28	0.24	0.037
Total Project, pounds per hour[e]	240.41	13.32	1,903.38	32.16	23.73
Maximum Daily Emissions, lb/day					
Turbines and Duct Burners[b]	2,536.75	319.1	11,574.8	406.5	567.1
Auxiliary Boiler[c]	4.9	1.3	16.6	1.9	2.24
Emergency Generator Engine	2.84	0.02	4.0	0.63	0.065
Diesel Fire Water Pump Engine	2.16	0.003	0.28	0.24	0.037
Total Project, pounds per day[e]	2,546.7	319.1	11,595.7	409.3	567.2
Maximum Annual Emissions, tpy					
Turbines and Duct Burners[b]	143.95	16.34	639.05	34.51	80.66
Auxiliary Boiler[c]	0.23	0	0.86	0.088	0
Emergency Generator Engine	0.071	0.0002	0.10	0.02	0.002
Diesel Fire Water Pump Engine	0.054	0.00007	0.007	0.006	0.0009
Total Project, tons per year[e]	144.3	16.3	640.0	34.6	80.7

Notes:
[a] See Appendix 6.2-1, Table 6.2-1.8 for calculations.
[b] Includes startup emissions.
[c] Auxiliary boiler is not on for the hour nor the day nor the annual baseload scenario that generates maximum SOx and PM_{10} emissions.
[d] Emergency generator engine (50 hrs/yr) and fire water pump engine (50 hrs/yr) will not be tested during a startup hour, and hence, are not added to turbine and auxiliary boiler startup hourly emissions.
[e] Totals may be rounded, and are not necessarily the sum of the emission rates above because not all the listed equipment runs during the maximum emissions hour.

Maximum Hourly Emissions:

- Both turbines are in startup mode, with the second turbine startup initiated one hour after the first.

Maximum Daily Emissions:

For NOx, CO, and VOC

- Each turbine operates in cold startup or shutdown mode for 6 hours.
- Each turbine operates at full load with duct firing for 18 hours.

For SO_2 and PM_{10}/ $PM_{2.5}$:

- Each turbine operates at full load with duct firing for 24 hours.

Maximum Annual Emissions:

For NOx and VOC (i.e., weekend and weekday hot start scenario)

- Each turbine operates in startup or shutdown mode for 547.5 hours per year.
- Each turbine operates at full load with duct firing for 800 hours.
- Each turbine operates at full load without duct firing for 6,683 hours .

For CO (i.e., weekend shutdown and weekday hot start scenario)

- Each turbine operates in startup or shutdown mode for 624 hours per year.
- Each turbine operates at full load with duct firing for 800 hours.
- Each turbine operates at full load without duct firing for 3,800 hours.

For SO_2 and PM_{10}/ $PM_{2.5}$ (baseload scenario)

- Each turbine operates at full load with duct firing for 800 hours per year.
- Each turbine operates at full load without duct firing for 7,960 hours per year.

Because all the equipment does not operate at the same time, the maximum emissions hour does not contain the maximum emissions each piece of equipment can emit in one hour. Detailed emission calculations appear in Appendix 6.2-1, Table 6.2-1.8. Auxiliary boiler emissions characteristics are shown in Table 6.2-1.2.

The applicant believes that transient, rapid load changes may be needed that result in short-term elevated NOx emissions from the combined-cycle plant, and hence proposes the inclusion of the following NOx emissions excursion language in the conditions of certification:

> *Compliance with the NOx emission limitations shall not be required during short-term excursions limited to a cumulative total of 15 hours per calendar year. Short-term excursions are defined as 15-minute periods designated by the owner/operator and approved by the APCO that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, during which time the 15-minute average NOx concentration exceeds 2.0 ppmvd @ 15% O_2. The maximum 3-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmvd @ 15% O_2. Examples of transient load conditions include, but are not limited to, the following: (1) rapid gas turbine load changes initiated by the California Independent System Operator or a successor entity when the plant is operating under Automatic Generation Control; (2) rapid combustion load changes due to activation of a plant automatic safety or equipment protection system; and (3) initiation and termination of duct firing. All emissions during short-term excursions shall accrue towards the daily and annual emissions limits of this permit and shall be included in all calculations of daily and annual mass emission rates as required by this permit.*

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential 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.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.
[25] Currently 187 substances are listed.

the SJVAPCD toxic air contaminant list has been evaluated herein. Emission factors were determined by reviewing the available technical data, determining the products of combustion, or using material balance calculations.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00 and Table 3.4-1 of the Background Document for Section 3.1) and the Air Resources Board's California Air Toxics Emission Factors (CATEF) database for gas turbines. Specifically, factors for all pollutants except hexane and individual PAHs were taken from AP-42.[26] AP-42 did not contain factors for hexane, and did not include speciated data for PAHs. Factors for these pollutants were taken from the CATEF database (mean values). Noncriteria pollutant emission factors for the auxiliary boiler were taken from data compiled by the Ventura County APCD.

The noncriteria pollutants that may be emitted from the Project are shown in Table 6.2-25. Appendix 6.16, Tables 6.16-1, 6.16-2, and 6.16-3 provide the detailed emission calculations for noncriteria pollutants from the gas turbines, auxiliary boiler, and emergency standby generator engine, respectively. The sole noncriteria pollutant emitted by the Diesel-fueled emergency standby fire water pump engine—Diesel exhaust particulate or the PM_{10} emitted by the engine—had already been shown in Appendix 6.2-1, Table 6.2-1.4. Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein, benzene and formaldehyde emission factors reflect any control effectiveness. As discussed above, these factors are based on test data published by the USEPA[27] rather than any assumption regarding catalyst control efficiency. As emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the turbines are not subject to the MACT requirements of 40 CFR Part 63.

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[26] Factors for acrolein, formaldehyde, and benzene conservatively reflect no short-term (1 hour) use of an oxidation catalyst and were taken from Table 3.1-3 of AP-42 Section 3.1.

[27] USEPA. *Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines,* Table 3.4-1, April 2000, http://www.epa.gov/ttn/chief/ap42/ch03/index.html.

TABLE 6.2-25
NONCRITERIA POLLUTANT EMISSIONS FOR THE PROJECT

Pollutant	Emission Factor (lb/MMscf)	Emissions lb/hr (each)	Emissions ton/yr
Gas Turbines (two with Duct Burners)			
Ammonia	-[a]	35.4	235.8
Propylene	7.71×10^{-1}	1.79	12.3
HAPs			
Acetaldehyde	4.05×10^{-2}	0.094	0.65
Acrolein [b]	6.49x10-3/3.69×10^{-3}	0.015	0.059
Benzene [b]	1.22x10-2/3.33×10^{-3}	0.028	0.053
1,3-Butadiene	4.36×10^{-4}	1.0×10^{-3}	7.0×10^{-3}
Ethylbenzene	3.24×10^{-2}	0.075	0.52
Formaldehyde [b]	7.19x10-1/3.67×10^{-1}	1.67	5.9
Hexane	2.59×10^{-1}	0.60	4.1
Naphthalene	1.32×10^{-3}	3.1×10^{-3}	2.1×10^{-2}
Polycyclic Aromatic Hydrocarbons (PAHs)	-- see Appendix 6.16 for individual PAHs --		
Propylene Oxide	2.94×10^{-2}	0.068	0.47
Toluene	1.32×10^{-1}	0.31	2.1
Xylene	6.49×10^{-2}	0.15	1.0
Total HAPs (two turbines)			14.9
Auxiliary Boiler			
Propylene	0.53	0.020	0.012
HAPs			
Acetaldehyde	8.9×10^{-3}	<0.01	<0.01
Acrolein	2.70×10^{-3}	<0.01	<0.01
Benzene	4.31×10^{-3}	<0.01	<0.01
Ethylbenzene	6.90×10^{-2}	<0.01	<0.01
Formaldehyde	0.221	<0.01	<0.01
Hexane	4.6×10^{-3}	<0.01	<0.01
Naphthalene	3.0×10^{-4}	<0.01	<0.01
Polycyclic Aromatics	1.0×10^{-4}	<0.01	<0.01
Toluene	2.7×10^{-2}	<0.01	<0.01
Xylene	2.0×10^{-2}	<0.01	<0.01
Total HAPs			0.008
Emergency Standby Generator Engine (natural gas-fueled)			
Propylene	5.38E+00	3.43E-02	8.58E-04
HAPs			
Acetaldehyde	5.29E-01	3.37E-03	8.43E-05
Acrolein	5.90E-02	3.76E-04	9.41E-06
Benzene	2.18E-01	1.39E-03	3.48E-05
1,3-Butadiene	3.67E-01	2.34E-03	5.85E-05
Ethylbenzene	7.11E-02	4.53E-04	1.13E-05
Formaldehyde	53.50	3.41E-01	8.53E-03
Hexane	1.12E+00	7.17E-03	1.79E-04
Naphthalene	2.51E-02	1.60E-04	4.00E-06
PAHs (listed below)	2.53E-04	1.62E-06	4.04E-08
Anthracene	1.19E-04		

TABLE 6.2-25
NONCRITERIA POLLUTANT EMISSIONS FOR THE PROJECT

Pollutant	Emission Factor (lb/MMscf)	Emissions lb/hr (each)	Emissions ton/yr
Benzo(α)anthracene	5.88E-05		
Benzo(α)pyrene	2.70E-06		
Benzo(b)fluoranthene	4.09E-05		
Benzo(k)anthracene	7.83E-06		
Chrysene	1.43E-05		
Dibenz(a,h)anthracene	2.70E-06		
Indeno(1,2,3-cd)pyrene	7.17E-06		
Toluene	2.39E-01	1.52E-03	3.81E-05
Xylene	6.46E-01	4.12E-03	1.03E-04
Total HAPs			9.05E-03
Emergency Standby Fire Water Pump Engine (Diesel-fueled)			
Diesel exhaust particulate	0.059 g/bhp-hr	0.037	9.40E-04

[a] Ammonia emissions calculated from 10 ppm ammonia slip rate. See Appendix 6.2-1, Table 6.2-1.1.
[b] The first emission factor is uncontrolled such as occurs in the early mode of commissioning (see text Footnote 13). The second emission factor is controlled with a CO oxidation catalyst (see text Footnote 14).

Greenhouse Gas Emissions

California has adopted comprehensive legislation, AB 32, to reduce GHG emissions produced within California including the emission from power generated to serve California customers. The ARB is currently developing regulations to implement the AB 32, and has adopted reporting regulations for emitters of greenhouse gases in California including power plants.[28] These proposed reporting regulations will be modified in the near future, followed by review and approval by the Office of Administrative Law later this year. ARB will be adopting comprehensive regulations to reduce the amount of GHG emissions generated to produce the electricity consumed by California to 1990 levels. The Avenal Energy Project will report its GHG emissions as required by the new regulations, and will comply with future GHG regulations.

A power plant is dispatched by the California Independent System Operator (CalISO) when its heat rate is lower than or equal to the next available facility, or when needed for reliability purposes. A combined-cycle power plant such as the Avenal Energy Project has a lower heat

[28] 17 Cal. Code of Regs. 95100 *et. seq*.

rate (i.e., greater efficiency) than many other power plants. Therefore, when combined-cycle power plants operate, they are often displacing a less-efficient power plant. Higher efficiency means lower GHG emissions. Therefore, a new facility like this Project, operating at high efficiency, reduces overall GHG emissions to serve a specific load. Furthermore, as California load-serving entities and publicly-owned utilities begin to reduce their import of coal-generated electric power to serve California customers, they will need to replace that coal-generated energy with less carbon intensive sources, including renewable generation and natural gas-fired generation. Both sources will be needed to serve California load, reduce the GHG emissions accompanying the electricity used by California, and maintain the reliability of the electric grid.

The greenhouse gas emissions from the Project are summarized in the Cumulative Impacts section.

6.2.5.1.2 *Air Quality Impact Analysis*

District new source review regulations require ambient air quality modeling analyses and other impact assessments. An ambient air quality impact assessment is also required by the CEC for CEQA review. These analyses are presented in this section.

Air Quality Modeling Methodology[29]

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

The impact analysis was used to determine the maximum ground-level impacts of the Project. The results were compared with established state and federal ambient air quality standards and PSD significance levels. If the standards were not exceeded under these worst-case conditions, then it is demonstrated that no exceedances are expected under any conditions. In accordance with the air quality impact analysis guidelines developed by USEPA[30] and the ARB,[31] the ground-level impact analysis includes the following assessments:

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[29] A modeling protocol (see Appendix 6.2-2) was submitted to the SJVAPCD on August 14, 2007, verbally approved by telephone in October 2007, and approved by email on January 22, 2008 (see Appendix 6.2-2).
[30] USEPA. Guideline on Air Quality Models, 40 CFR Part 51, Appendix W.

- 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

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[31] ARB. *Reference Document for California Statewide Modeling Guideline,* April 1989.

$\sigma_y\sigma_z$ = 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 USEPA 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 USEPA 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:

- Gas turbine screening modeling procedures
- Refined air quality impact analysis
- Specialized modeling
- Existing ambient pollutant concentrations and preconstruction monitoring
- Results of the ambient air quality modeling analyses
- PSD increment consumption

Modeling for the proposed project was performed in accordance with the modeling protocol submitted to the District, EPA, and CEC. The modeling procedures used for each type of modeling analysis are described in more detail in the following sections. Two EPA guideline models were used for different meteorological conditions in the ambient air quality impact analysis.

The EPA-approved AERMOD[32] model was used to evaluate impacts in simple, intermediate, and complex terrain. AERMOD is a Gaussian dispersion model capable of assessing impacts from a variety of source types in areas of simple, intermediate, and complex terrain. The model can account for settling and dry deposition of particulates; area, line, and volume source types; downwash effects; and gradual plume rise as a function of downwind distance. The model is capable of estimating concentrations for a wide range of averaging times (from one hour to one

[32] The acronym AERMOD was derived from American Meteorological Society/Environmental Protection Agency Regulatory Model.

year), and was applied with three years of actual meteorological data recorded at the Hanford, CA monitoring station. AERMOD replaces the previous EPA-recommended model, Industrial Source Complex, Version 3 (ISCST3), which has been used for many years for air quality impact analyses in CEC AFCs. The analysis using the AERMOD model is discussed in more detail below.

The SCREEN3 model was used to evaluate gas turbine impacts under inversion breakup and fumigation conditions because these are special meteorological conditions. The SCREEN3 model uses a range of meteorological conditions that could occur under inversion breakup fumigation. Because the emissions from the emergency standby generator and fire water pump engines are so small compared to the gas turbine emissions, they are excluded from this single-source model used for the fumigation analysis. The fumigation analysis is discussed in more detail below.

Gas Turbine Screening Modeling

The screening and refined air quality impact analyses were performed using the AERMOD model. The screening modeling is performed to determine the combination of ambient temperature and CTG operating conditions that generates the highest ambient air quality levels for each pollutant and averaging period. The refined modeling uses the stack parameters indicated by the screening level modeling to cause the highest ambient impact for each combination of criteria pollutant and averaging period.[33]

Inputs required by AERMOD include the following:

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

Standard AERMOD control parameters were used, including stack tip downwash, non-screening mode, non-flat terrain, and sequential meteorological data check. Stack-tip downwash, which adjusts the effective stack height downward following the methods of Briggs (1972) for cases

[33] The combinations are derived from the ambient air quality standards (see Table 6.2-1)

where the stack exit velocity is less than 1.5 times the wind speed at stack top, was selected per EPA guidance. The rural default option was used by not invoking the URBANOPT option.[34]

The required emission source data inputs to both models used in this analysis include source locations, source elevations, stack heights, stack diameters, stack exit temperatures and velocities, and emission rates. The source locations are specified for a Cartesian (x,y) coordinate system where x and y are distances east and north in meters, respectively. The Cartesian coordinate system used is the Universal Transverse Mercator (UTM) Projection. The stack height that can be used in the model is limited by federal Good Engineering Practice (GEP) stack height restrictions, discussed in more detail below. In addition, Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, current version 04274) requires nearby structure dimensions to calculate the impacts of building downwash.

For the purposes of modeling, a stack height beyond what is required by Good Engineering Practices (GEP) is not allowed (SJVAPCD Regulation 2-2-418). 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 assure 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 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. The USEPA guidance[35] for determining GEP stack height is as follows:

$$H_g = H + 1.5L$$

where

H_g = GEP 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

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[34] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the proposed project site.

[35] USEPA. "Guideline for Determination of Good Engineering Practice Stack Height," Revised 6/85.

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 turbine/HRSG stacks, the nearby (influencing) structures are the HRSGs, which are 80 feet (24.4 m) high, 254 feet (77.5 m) long, and 26 feet (7.9 m) wide. Thus H = 80 ft and L = 80 feet, and H_g = 80 ft + (1.5 * 80 ft) = 200 ft, and hence, the stack height of 145 feet does not exceed GEP stack height.

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 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 6.2-2, Table 6.2-2.1 and Figure 6.2-2.1.

Screening Procedures

To assure 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. The screening procedure analyzed the turbine 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 6.2-2, Table 6.2-2.2. These operating conditions represent maximum and minimum turbine loads (100 percent and 50 percent) at maximum, annual average and minimum ambient operating temperatures (111°F, 63°F and 32°F). The determination of the worst-case gas turbine operating condition depends on how changes in emissions rates and stack characteristics (plume rise characteristics) interact with terrain features. For example, lower mass emissions resulting from lower load operations may cause higher concentrations than other operating conditions because lower final plume height may have a greater significant interaction with terrain features.

Screening AERMOD modeling runs were performed using normalized emission rates to assess the zone of impact and relative magnitude of the impacts. For the AERMOD gas turbine screening modeling, each gas turbine was modeled with a unit emission rate of 1 gram per second to obtain maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual average ratios of concentration to emission rate (abbreviated symbolically as χ/Q in units of $\mu g/m^3$ per g/s). These χ/Q values were multiplied by the actual emission rate in grams per second from the gas turbine to calculate ambient impacts for NO_2, CO, SO_2, and PM_{10}/ $PM_{2.5}$ in units of $\mu g/m^3$. Stack characteristics used in the screening modeling analysis are shown in Appendix Table 6.2-2.2.

The operating conditions were screened for worst-case ambient impact using the AERMOD model and five years of meteorological data collected at Hanford, CA, as described above. The results of the screening procedure are presented in Appendix 6.2-2, Table 6.2-2.3. The screening analyses included simple, intermediate, and complex terrain. Terrain features were taken from USGS DEM data and 7.5 minute quadrangle maps of the area. The stack parameters and emission rates corresponding to the operating case that produced the maximum impacts in the gas turbine screening analysis for each pollutant and averaging period were used in the refined modeling analysis to evaluate the impacts of the turbines. For the unit impacts analysis, the CEC

staff's recommendation regarding receptor grid spacing[36] has been enhanced. Instead of the 100-meter resolution between 100 and 1,000 meters from the fenceline, a 25-meter fine grid was placed around each maximum impact point, extending 1,000 meters in each east, west, north and south direction.

Refined Air Quality Impact Analysis

AERMOD was used to estimate proposed project impacts in simple, intermediate and complex terrain. The AERMOD model was used to calculate 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentrations.

Refined modeling was performed in two phases: coarse grid modeling and fine grid modeling. Preliminary modeling was performed with the coarse grid to locate the areas of maximum concentration. Fine grids were used to refine the location of the maximum concentrations. The complete modeling input for each pollutant and averaging period is shown in Appendix 6.2-2, Tables 6.2-2.4 and -2.5 for normal operating and startup conditions, respectively.

The model receptor grids were derived from 30-meter DEM data. The Commission guidance cited above was used to locate receptors. Twenty five-meter refined receptor grids were used in areas where the coarse grid analyses indicated modeled maxima for each site plan would be located.

Receptors for the refined modeling analysis were from USGS DEM data for the following 7.5-minute quadrangles:

- Guijarral Hills,
- Huron,
- Westhaven,
- Avenal,
- La Cima,
- Kettleman City,
- Garza Peak,
- Kettleman Plain; and

[36] 25-meter resolution along the facility fenceline to 100 meters from the fenceline; 100 meter resolution from 100 meters to 1,000 meters from the fenceline; and 250-meter spacing out to as far as 10 km from the site.

- Los Viejos.

These terrain data are included in the modeling CD submitted to the CEC as part of this AFC.

Specialized Modeling Analyses

- **Turbine Startup:** Facility impacts were also modeled during the combined startup of the two turbines to evaluate a realistic case for the potentially highest short-term impacts. Emission rates used for this scenario were based on an engineering analysis of available data, which included source test data from startups of the gas turbines at several other projects. A summary of the data evaluated in developing these emission rates is shown in Appendix 6.2-1, Tables 6.2-1.6 and 6.2-1.7. Turbine exhaust parameters for the minimum operating load point (50 percent) were used to characterize turbine exhaust during startup and a maximum one-hour NOx emission rate of 240 lb/hr was used during a combined startup of both turbines. Both turbines had stack parameters demonstrated in the screening analysis to result in the highest modeled impacts for short-term averaging periods. Startup impacts were evaluated using AERMOD for each combination of a criteria pollutant and one of the following averaging periods: 1-hour, 3-hour, 8-hour and 24-hour. Emission rates and stack parameters used in the startup modeling analysis are shown in Appendix Table 6.2-2.5.

- **Fumigation Modeling:** 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 cause high ground-level pollutant concentrations because the plume is unable to rise upwards normally due to the stable layer capping it from above, and be drawn to the ground by turbulence within the unstable layer. Although fumigation conditions rarely last as long as one 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 as required by EPA guidance.

  The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from the USEPA[37] was followed in evaluating fumigation impacts. Inversion breakup fumigation is generally a short-term phenomenon but was evaluated here as persisting for up to 24 hours. SCREEN3 was used to model one-hour unit impacts from the turbines under 2.5 m/s winds and F stability (for fumigation impacts) and under all meteorological conditions. For averaging periods longer than one hour, impacts were adjusted using standard EPA persistence factors (3 hours, 0.9; 8 hours, 0.7; 24 hours, 0.4).

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

Because SCREEN3 is a single-source model, a single turbine is modeled, and the impacts are multiplied by 2 for the two project turbines. As shown in more detail in Appendix 6.2-2, Table 6.2-2.6, the maximum fumigation impact from the HRSG stacks occurred approximately at distances between 12 and 17 km from the facility, depending on the operating condition (i.e., 50% load or 100% base load, with or without duct firing). SCREEN3 would set the fumigation impact from the auxiliary boiler, emergency standby generator engine, and emergency fire water pump engine to zero for fumigation calculations because the distances to the maximum fumigation impacts from these other sources occur less than 2,000 meters from the facility. As also shown in Appendix Table 6.2-2.6, potential impacts under fumigation conditions are higher than those predicted by SCREEN3 for simple, flat terrain, but as will be shown later in this section, fumigation impacts would be lower than the maximum impacts calculated by AERMOD under downwash conditions and actual terrain.

Turbine Commissioning: There are two high emissions scenarios possible during commissioning. The first would be the period prior to SCR system and oxidation catalyst installation, when the combustor is being tuned. Under this scenario, NOx emissions would be high because the NOx emissions control system would not be functioning and because the combustor would not be tuned for optimum performance. CO emissions would also be high because combustor performance would not be optimized and the CO emissions control system would not be functioning; however, CO emissions would not be expected to exceed levels analyzed under startup conditions.

The second high emissions scenario would occur when the combustor had been tuned but the SCR installation was not complete, and other parts of the turbine operating system were being checked out. This is likely to occur under transient conditions, characterized by 50 percent load operation. Since the combustor would be tuned but the control system installation would not be complete, CO levels would not be expected to be elevated above startup levels but NOx levels would again be high.

Appendix Table 6.2-2.7 presents both the emission rates and stack exhaust parameters used in the refined modeling impact analysis of commissioning and the full year that includes commissioning.

- **Ozone Limiting:** In accordance with EPA guidance, one-hour NO_2 impacts during proposed project operation were modeled using the Plume Volume Molar Ratio Method (PVMRM) adaptation of the Ozone Limiting Method (Cole and Summerhays, 1979). AERMOD PVMRM was used to calculate the NO_2 concentration based on the PVMRM method, and hourly ozone data. Hourly ozone data collected at the Hanford, CA monitoring station during the years 2000-2004 were used in conjunction with PVMRM to calculate hourly NO_2 concentrations from hourly NOx concentrations. Missing hourly ozone data were substituted prior to use with day-appropriate values (e.g., from the previous day, or the next day, for the same hour). Any other missing hourly ozone data were substituted with 40 ppb ozone (typical ozone tropospheric background level). The PVMRM involves an initial comparison of the estimated maximum NOx concentration and the ambient O_3 concentration left in the plume after reaction of NO with O_3 to

determine which is the limiting factor with respect to NO_2 formation. If the remaining O_3 concentration is greater than the maximum NOx concentration, total conversion is assumed. If the NOx concentration is greater than the remaining O_3 concentration, the formation of NO_2 is limited by the remaining ambient O_3 concentration. In this case, the NO_2 concentration is set equal to the O_3 concentration plus a correction factor that accounts for in-stack and near-stack thermal conversion. Annual NO_x impacts were converted to NO_2 using the EPA-guidance Ambient Ratio Method and the nationwide default conversion ratio of 0.75 for the annual average NO_2/NO_x ratio.

Preconstruction Monitoring

To assure that the impacts from the Project will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, the existing air quality in the area of the Project is analyzed (see Section 6.2.3). Although federal PSD regulations require preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area, the Project is exempted from this requirement because the predicted air quality impacts would not exceed the *de minimis* levels listed in Table 6.2-26 as shown later in this section.

TABLE 6.2-26
PSD PRECONSTRUCTION MONITORING EXEMPTION LEVELS

Pollutant	Averaging Period	De minimis Level
CO	8-hr average	575 $\mu g/m^3$
NO_2	annual average	14 $\mu g/m^3$
SO_2	24-hr average	13 $\mu g/m^3$

The Project is relying on air quality monitoring data collected at the monitoring stations discussed in Section 6.2.3 to satisfy the requirement for preconstruction monitoring. In such a case, in accordance with Section 2.4 of the USEPA PSD guideline, the last three years (i.e., 2004-2006) of ambient monitoring data have been used because they are representative of the area's air quality where the maximum impacts occur due to the proposed source. According to 40 CFR 51, Appendix W, Section 9.2 the background data need not be collected on site, as long as the data are representative of the air quality in the subject area. Three criteria are applied in determining whether the background data are representative: (1) the monitoring location, (2) data quality, and (3) how current are the data.[38] These criteria are defined as follows:

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

- 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.

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

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. The data have been collected within the preceding three years, and thus all meet the criterion for being current. The locations of the data sets used to represent background concentrations of each pollutant are discussed individually below.

<u>NO_2</u>

Ambient NO_2 data have been collected at the Hanford monitoring station for more than 10 years. The Hanford monitoring station is located approximately 28 miles northeast of the Project site. As the Project area itself is sparsely populated, there are few sources of air pollution (other than vehicle traffic) to affect air quality there. The NO_2 levels monitored at the Hanford monitoring station reflect regional NO_2 concentrations in the vicinity of the Project, and thus meet the criterion for location.

<u>SO_2</u>

The nearest ambient SO_2 monitors to the Project are in Bakersfield and Sacramento. These two cities are far more populated and developed than the relatively rural and undeveloped Project area, so even the extremely low measured SO_2 concentrations in Bakersfield and Sacramento provide overestimated background SO_2 levels for assessing the impacts of the Project, and thus meet the location criterion.

<u>CO</u>

The nearest monitoring station that records CO is located in Visalia, approximately 44 miles northeast of the Project site. Visalia is far more populated and developed than the rural project area, so the CO data collected there conservatively overestimate CO concentrations in the Project area.

PM_{10}

PM_{10} concentrations are monitored at several locations in Kings County. The nearest PM_{10} monitors providing recent PM_{10} data are in Hanford and Corcoran, 27 miles east of the Project site. Populations of 42,000 and 22,000 in Hanford and Corcoran, respectively, suggest that the PM_{10} levels recorded there would provide a conservative upper bound for PM_{10} concentrations in the Project area.

$PM_{2.5}$

$PM_{2.5}$ concentrations are monitored in Kings County only at the Patterson Avenue, Corcoran location, 27 miles east of the Project site. A population of 22,000 in Corcoran suggests that the PM_{10} levels recorded there would provide a conservative upper bound for $PM_{2.5}$ concentrations in the Project area.

Results of the Ambient Air Quality Modeling Analyses

The maximum Project impacts calculated from each of the modeling analyses described above are summarized in Table 6.2-27. The detailed results of the fumigation modeling analysis are summarized in Appendix 6.2-2, Table 6.2-2.6.

TABLE 6.2-27
NORMAL OPERATION AIR QUALITY MODELING RESULTS

Pollutant	Averaging Time	Modeled Maximum Concentrations ($\mu g/m^3$)		
		Normal Operations AERMOD	Startup/Shutdown AERMOD	Fumigation SCREEN3
NO_2	1-hour	158	190	5.2
	Annual	0.6	[a]	[c]
SO_2	1-hour	9.7	7.7	2.0
	3-hour	4.2	2.7	1.7
	24-hour	1.2	b	0.7
	Annual	0.09	a	c
CO	1-hour	154	2,175	6.4
	8-hour	12.3	337	3.8
PM_{10}/ $PM_{2.5}$	24-hour	2.9	2.9	1.2
	Annual	0.8	[a,b]	[c]

Notes:
[a] Not applicable, because startup/shutdown emissions are included in the modeling for annual average.
[b] Not applicable, because emissions are not elevated above normal operation levels during startups/shutdowns.
[c] Not applicable, because inversion breakup is a short-term phenomenon and as such is evaluated only for short-term averaging periods.

Confirmation that preconstruction monitoring was not required is shown in Table 6.2-28 because the maximum ambient impacts do not exceed *de minimis* levels.

TABLE 6.2-28
EVALUATION OF PRECONSTRUCTION MONITORING REQUIREMENTS

Pollutant	Averaging Time	Exemption Concentration (μg/m^3)	Maximum Modeled Concentration (μg/m^3)	Monitoring Required?
NOx	annual	14	0.6	no
SO_2	24-hr	13	1.2	no
CO	8-hr	575	337	no

Impacts During Turbine Commissioning

During the gas turbine commissioning phase, NO_2 and CO impacts may be higher than under the operating conditions evaluated above. The commissioning period is comprised of equipment tests and verification. These tests and the associated NO_x and CO emissions are briefly summarized below. The emissions calculations are shown in more detail in Appendix 6.2-2.

- Full Speed No Load Tests (FSNL) – The tests include a test of the gas turbine ignition system, a test to assure that the CTG is synchronized with its electric generator, and a test of the CTG's overspeed system.

- Minimum Load Tests – These tests will occur over several days. During this testing period, the CTG combustor will be tuned to minimize emissions and other checks will be performed. This test period will allow for complete combustion path warm-up, required for removing all debris that could potentially damage the SCR catalyst.

- Multiple Load Tests (SCR/Oxidation Catalyst Operational at Various Levels) – These tests will occur over several days. By the beginning of this test period, the control systems will be installed and will be tuned to achieve NO_x and CO control at design levels.

- Performance Tests (SCR/Oxidation Catalyst at Full Control) – These tests will also occur over a several-day period, with the CTGs operating from minimum to maximum load.

It is assumed that the maximum modeled NO_2 and CO impact during commissioning will occur under the gas turbine operating conditions that are least favorable for dispersion. These conditions are expected to occur under low-load conditions.

The maximum potential air quality impacts during commissioning are shown in Table 6.2-29. Because there will be a staggered commissioning schedule, the two CTGs will not undergo

commissioning simultaneously. Consequently, the impacts shown in Table 6.2-29 are based on one CTG undergoing commissioning and the second CTG undergoing a normal startup/shutdown.

TABLE 6.2-29
MODELED RESULTS DURING SEQUENTIAL COMMISSIONING (BOTH CTGS)

Pollutant/Averaging Period	Modeled Concentration, $\mu g/m^3$
NO_2 - 1-hour	187
CO - 1-hour	1,164
CO - 8-hour	251

Ambient Air Quality Impacts

To conservatively determine the Project's air quality impacts, the modeled maximum potential concentrations are added to the maximum background ambient air concentrations, and compared to the applicable ambient air quality standards. The modeled concentrations were presented in Tables 6.2-27 and 6.2-29, while the maximum background monitored concentrations were presented in Tables 6.2-3 through 6.2-8. Table 6.2-30 presents the maximum concentrations of NOx, SO_2, CO, PM_{10} and $PM_{2.5}$ recorded for 2004 through 2006 from the Hanford, Bakersfield, Visalia, and Corcoran stations.

Maximum ground-level impacts due to operation of the Project are shown together with the ambient air quality standards in Table 6.2-31. Using the conservative assumptions described earlier, the results indicate that the Project will not cause or contribute to violations of any state or federal air quality standards, with the exception of the state PM_{10} and $PM_{2.5}$ standards. For these pollutants, existing concentrations already exceed the state and federal standards.

TABLE 6.2-30
MAXIMUM BACKGROUND CONCENTRATIONS, 2004-2006 (µg/m^3)

Pollutant	Averaging Time	2004	2005	2006
Hanford				
NO_2	1-Hour Annual	129.7 22.6	135.4 22.6	**137.2** [a] **22.6**
Sacramento				
SO_2	1-Hour 3-Hour 24-Hour Annual	21.3 19.2[c] 7.9 2.6	**47.2** **43.2**[c] **7.9** **2.6**	[b] [b] 5.2 2.6
Visalia				
CO	1-Hour 8-Hour	4,111 2,489	**4,222** **2,900**	[b] [b]
Hanford/Corcoran (higher value used)				
PM_{10}	24-Hour Annual	217 43.1	131 41.1	**304** **46.3**
Corcoran				
$PM_{2.5}$	24-Hour Max 98th Percentile 24-Hr 3-Year Avg 98th Percentile 24-Hour Annual Arith. Mean 3-Year Avg AAM [d]	61.0 49.4 52 17.4 **18**	**92.5** **74.5** **55** **17.5** 17	74.2 50.1 **58** 16.9 17

Notes:
[a] Bolded values are maxima.
[b] Insufficient data.
[c] Estimated from 1-hour concentrations by use of USEPA averaging time ratios (i.e., 0.9 for 3 hours)
[d] Annual arithmetic mean.

TABLE 6.2-31
MODELED MAXIMUM PROJECT IMPACTS

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 Annual	190 0.5	137.2 22.6	327.2 23.1	470/338[a] -	- 100
SO_2	1-hour 3-hour 24-hour Annual	9.7 4.3 1.5 0.09	47.2 43.2 7.9 2.6	56.9 47.5 9.4 2.7	650 - 109 -	- 1300 365 80
CO	1-hour 8-hour	2,175 337	4,111 2,489	6,286 2,826	23,000 10,000	40,000 10,000
PM_{10}	24-hour Annual[b]	2.9 0.8	304 46.3	307 47.1	50 20	150 -
$PM_{2.5}$	24-hour Annual[b]	2.9 0.8	58 18	60.9 18.8	- 12	35 15

Notes:
[a] Existing and proposed CAAQS
[b] Annual Arithmetic Mean

PSD Significant Emission Levels, Significant Impact Levels and Increment Consumption

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

Project emissions are evaluated to determine whether the potential increase in emissions will be significant. Because this facility is a new major stationary source, the level of emissions that requires an analysis of ambient impacts is determined on a pollutant-specific basis. The emissions increases are those that will result from the new equipment. For new facilities that include large gas turbines with fired HRSGs, USEPA considers a potential increase of 100 tons per year of any of the criteria pollutants to be significant[39]; hence, the Project is considered a new major source. Table 6.2-32 shows that the potential emissions increases of NOx and CO are considered significant.

TABLE 6.2-32
COMPARISON OF EMISSIONS INCREASE WITH PSD SIGNIFICANT EMISSION LEVELS

Pollutant	Emissions (tons per year)	Significant Emission Levels (tons per year)	Significant?
NOx	159	100	Yes
SO_2	17	100	No
VOC	35	100	No
CO	674	100	Yes
PM_{10}	81	100	No

Because an ambient air quality impact analysis is required for the Project, the analysis is used to determine if Project impacts are significant. The determination of significance is based on whether the impacts exceed established significance levels (40 CFR 52.21) shown in Table 6.2-33. If the significance levels are not exceeded, no further analysis is required.

[39] 40CFR Part 52.21

TABLE 6.2-33
PSD LEVELS OF SIGNIFICANCE

Pollutant	Averaging Time	Significant Impact Levels ($\mu g/m^3$)	Maximum Allowable Increments ($\mu g/m^3$)
NO_2	Annual	1	25
SO_2	3-hour 24-Hour Annual	25 5 1	512 91 20
CO	1-hour 8-hour	2000 500	- -
PM_{10}	24-hour Annual	5 1	30 17

If a significant impact level would potentially be exceeded, then an analysis is required to demonstrate that the allowable increment for that criteria pollutant and averaging time will not be exceeded. Increments are the maximum increases in concentration that are allowed to occur above the baseline concentration. PSD maximum allowable increments are also shown in Table 6.2-33.

Table 6.2-32 showed that the Project will be a major source of NOx and CO. Emissions of SO_2, VOC, and PM_{10} from the Project will be below the 100 ton per year major source/significant emission level threshold (and VOC is a nonattainment pollutant and, therefore, is not subject to PSD review). However, emissions for these pollutants are carried through the PSD analysis to demonstrate that they will not result in any significant air quality impacts.

TABLE 6.2-34
COMPARISON OF MAXIMUM MODELED IMPACTS WITH PSD SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Modeled Impacts ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant?
NO_2	Annual	0.5	1	No
SO_2	3-Hour 24-Hour Annual	4.3 1.5 0.09	25 5 1	No No No
CO	1-Hour 8-Hour	2,175 337	2,000 500	Yes No
PM_{10}	24-Hour Annual	2.9 0.8	5 1	No No

The maximum modeled impacts from the Project are compared with the significant impact levels in Table 6.2-34 above. These comparisons show that, except for 1-hour CO, the maximum potential impacts are below the significant impact levels and no further analysis is required. The

CO significant impact does not require a PSD increment consumption analysis because maximum allowable increments do not exist for CO (see Table 6.2-33), and the maximum potential CO impact does not cause an exceedance of any ambient air quality standard (see Table 6.2-31). Although Project emissions of SO_2, VOC, and PM_{10} do not trigger PSD review, an analysis was conducted to determine whether the maximum potential impacts of the Project exceed the PSD significant impact levels for these criteria pollutants, because these levels are generally used as one measure of whether the project's ambient impacts would be significant.

6.2.5.2 Visibility Screening Analysis

The nearest Class I areas are located as follows:

- Pinnacles National Monument: 113 km
- Sequoia National Park: 113 km
- Ventana Wilderness: 127 km

The USEPA provided the appropriate Federal Land Managers (FLMs) with the Project modeling protocol to determine if a Class I area impact analysis is required for a proposed new source.[40] The FLMs evaluated the Project in terms of its maximum emissions and distance to each Class I area.[41] The FLMs confirmed that an analysis of potential impacts on visibility or other air quality-related values at Class I areas is not required for the Project.[42, 43, 44]

6.2.5.3 Construction Impacts Analysis

Emissions due to the construction phase of the Project have been estimated, including an assessment of emissions from onroad vehicle and nonroad equipment exhaust and the fugitive dust generated from material handling. A dispersion modeling analysis was conducted based on these emissions and use of ISCST3 as described in the Project's Air Dispersion Modeling and Health Risk Assessment Protocol. A detailed analysis of the emissions and ambient impacts is

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[40] USEPA. Personal communication from Carol Bohnenkamp of Region 9 to Sierra Research, November 2, 2007.
[41] National Park Service (NPS). Personal communication from Dee Morse, Air Resources Division, to Sierra Research, November 9, 2007.
[42] NPS. Email from Dee Morse to Sierra Research, November 21, 2007
[43] US Forest Service (USFS). Email from Mike McCorison, Angeles National Forest, to Sierra Research, November 21, 2007
[44] USFS. Email from Trent Procter, Pacific Southwest Region, to Sierra Research, November 28, 2007.

included in Appendix 6.2-3. The results of the analysis are shown in Table 6.2-35, and indicate that the maximum construction impacts will be below state and federal ambient air quality standards for all criteria pollutants, except that background PM_{10} and $PM_{2.5}$ levels alone exceed ambient air quality standards. Best management practice fugitive dust emission control techniques will be used. Project construction site impacts are not unusual in comparison to most construction sites; construction sites that use good fugitive dust suppression techniques and low-emitting vehicles typically do not cause violations of ambient air quality standards.

TABLE 6.2-35
MODELED MAXIMUM PROJECT CONSTRUCTION IMPACTS

Pollutant	Averaging Time	Maximum Facility Construction Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Construction Impact ($\mu g/m^3$)	State Standard ($\mu g/m^3$)	Federal Standard ($\mu g/m^3$)
NO_2	1-hour	163	137.2	300.2	470/338[a]	-
	Annual	1.1	22.6	23.7	-	100
SO_2	1-hour	2.0	47.2	49.2	650	-
	3-hour	1.0	43.2	44.2	-	1300
	24-hour	0.2	7.9	8.1	109	365
	Annual	0.004	2.6	2.6	-	80
CO	1-hour	1,245	4,111	5,356	23,000	40,000
	8-hour	178	2,489	2,567	10,000	10,000
PM_{10}	24-hour	4.7	304	308.7	50	150
	Annual[b]	0.2	46.3	46.5	20	-
$PM_{2.5}$	24-hour	4.7	58	62.7	-	35
	Annual[b]	0.2	18	18.2	12	15

Notes:
[a] Existing and proposed CAAQSs
[b] Annual Arithmetic Mean

Combustion Diesel PM_{10} emissions have also been evaluated for the maximum potential cancer risk. During the 27-month construction period, the maximum annual average Diesel particulate matter level would be 0.067 $\mu g/m^3$. The unit risk factor for DPM is 4.15E-4 per $\mu g/m^3$. Following OEHHA guidance[45] to use a 9-year period (instead of the 70-year lifetime exposure period) to account for the short, temporary duration of project construction, the resulting maximum potential cancer risk would be 3.6 in one million. The small area that would potentially experience a potential cancer risk above one in one million due to construction impacts is roughly the shape of a semicircle extending out from the south project boundary to a maximum distance of approximately 1,030 feet. There are no residences within this area.

[45] OEHHA. *Air Toxics Hot Spots Program Risk Assessment Guidelines: The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments,* August 2003.

6.2.6 CONSISTENCY WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

Project consistency with LORS at the federal, state and local district level is described below.

6.2.6.1 Consistency with Federal Requirements

The SJVAPCD has been delegated authority by the USEPA to implement and enforce most federal requirements that are applicable to the Project, including new source performance standards. Hence, compliance with District regulations assures compliance and consistency with the corresponding federal requirements. However, the SJVAPCD has not been delegated authority for PSD review. Therefore, a separate PSD application will be submitted to the USEPA.

The Project will also be required to comply with federal Acid Rain requirements (CAA Title IV). Because the District has received delegation for implementing Title IV through its Title V permit program, the Project will secure a District Title V permit that imposes the necessary requirements for compliance with the Title IV Acid Rain provisions.

As discussed in Section 6.2.5 on LORS, the federal PSD program requirements apply on a pollutant-specific basis because the Project will emit 100 tpy or more as a new major facility listed as one of the 20 PSD source categories in the federal Clean Air Act and PSD regulations (40CFR52.21). The emissions levels summarized in Table 6.2-34 showed that the Project is subject to PSD review for NOx and CO, because emissions of those pollutants exceed the 100 tpy thresholds.

Because the Project is subject to PSD review for NOx and CO, the facility is required to use BACT to control these pollutants. The discussion of BACT for NOx and CO is provided below in Section 6.2.6.3.

40 CFR § 52.21 (k) requires that the modeling be conducted with appropriate meteorological and topographic data necessary to estimate impacts. The Project modeling analyses used USGS topographic data for the surrounding area, and weather data gathered, published, and recommended by the SJVAPCD.

40 CFR § 52.21 (k) also requires a demonstration that emission increases subject to the PSD program will not interfere with the attainment or maintenance of any NAAQS for each applicable pollutant. As shown in Table 6.2-33, the Project will not cause or contribute to an exceedance of the following federal ambient air quality standard for which the SJVAPCD is in attainment of the standards: NO_2, SO_2 and CO. For PM_{10}, the background air quality exceeds the NAAQS as shown in Table 6.2-7 and 6.2-32, but the project contribution of PM_{10} is less than the significant impact level as shown in Table 6.2-36. The modeling analysis is discussed in detail in Section 6.2.6.2.

For an application that triggers PSD modeling requirements, 40 CFR § 52.21 (m) requires that ambient monitoring data be gathered for one year preceding the submittal of a complete application, or an USEPA-approved representative time period. However, if the air quality impacts of the facility do not exceed the specified *de minimis* levels, on a pollutant-specific basis, the facility is exempted from the preconstruction monitoring requirement. The air quality impacts of the Project's NOx and CO emissions are below the applicable *de minimis* levels, as shown in Table 6.2-30.

40 CFR § 52.21 (o) requires analysis of the impairment to visibility, soils and vegetation that would occur as a result of the Project. These analyses are provided in Sections 6.2.5.2, 6.4, and 6.6 of the AFC, respectively.

40 CFR § 52.21 (p) requires applications to demonstrate that emissions from a new or modified facility will not cause or contribute to the exceedances of any NAAQS or any applicable Class I PSD increment. As can be seen in Table 6.2-36, even the maximum potential impacts of the project in its vicinity are less than the Class I area PSD increments applicable at distances no closer than the 113 km to the nearest Class I area. The maximum potential impacts of the Project at such distant Class I areas would be far less than shown in Table 6.2-36.

TABLE 6.2-36
COMPARISON OF MAXIMUM MODELED IMPACTS AND CLASS I AREA PSD INCREMENTS

Pollutant	Averaging Time	Maximum Modeled Impacts ($\mu g/m^3$)	Class I Area PSD Increment ($\mu g/m^3$)	Exceedance?
NO_2	Annual	0.5	2.5	No
SO_2	3-Hour	4.3	25	No
	24-Hour	1.5	5	No
	Annual	0.09	2	No
PM_{10}	24-Hour	2.9	8	No
	Annual	0.8	4	No

Impacts on visibility and other air quality related values must also be evaluated for Class I areas if determined necessary by Federal Land Managers. After evaluating the maximum potential emissions of NOx, SOx, and PM_{10} from the Project, the appropriate National Park Service and U.S. Forest Service Federal Land Managers determined that no additional impact analysis is required (see discussion in Section 6.2.5.2).

6.2.6.2 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.

6.2.6.3 Consistency with Local Requirements: SJVAPCD

The SJVAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations in the eight counties[46] 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 levels are shown in Table 6.2-37, along with anticipated potential emissions from each unit and criteria pollutant. SJVAPCD Rule 2201 requires BACT for each unit emitting NOx, VOC, SOx, and PM_{10} (criteria pollutants) in excess of 2.0 pounds per highest day, and CO in excess of 200,000 pounds per year. The calculation of facility emissions was discussed in Section 6.2.5.1.1.

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[46] Including the portion of Kern County that is within the District boundaries.

TABLE 6.2-37
BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS

Pollutant	BACT Applicability Threshold (lbs/day)	Maximum emission level (lbs/day) - Bact required?			
		Turbine	Auxiliary Boiler	Emergency Standby Generator Engine	Emergency Standby Fire Water Pump Engine
Criteria Pollutants: SJVAPCD Regulation 2201					
VOC	2	407 - Yes	1.9 - No	0.63 - No	0.2 - No
NOx	2	2,537 - Yes	4.9 - Yes	2.8 - Yes	2.2 - Yes
SO_2	2	319 - Yes	1.3 - No	0.02 - No	0.003 - No
PM_{10}	2	567 - Yes	2.2 - Yes	0.06 - No	0.04 - No
CO	200,000 lbs/year	1,291,000 - Yes	1,720 - No	200 - No	14 - No

As shown in Table 6.2-37, BACT is required as follows:

- Turbines: NOx, VOC, SO_2, CO, and PM_{10};
- Auxiliary Boiler: NOx and PM_{10};
- Emergency Standby Generator Engine: NOx;
- Emergency Standby Fire Water Pump Engine: NOx.

BACT for the applicable pollutants was determined by reviewing the SJVAPCD BACT Clearinghouse,[47] the South Coast Air Quality Management District (SCAQMD) BACT Guidelines,[48] the ARB BACT Determinations,[49] and USEPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC).[50] A summary of the review is provided in Appendix 6.2-4.

As a BACT measure, the Project will limit the fuels burned by the turbines, auxiliary boiler, and emergency standby generator engine to natural gas, a clean burning fuel. Liquid fuels will not be fired at the Project except in the emergency standby Diesel-fueled fire water pump engine.

<u>NOx BACT</u> – BACT for NOx emissions from the gas turbine will be the use of low NOx emitting equipment and add-on controls. The Applicant has selected a gas turbine equipped with dry low-NOx combustors. The gas turbines will generate approximately 9 ppmvd NOx, 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 NOx emissions to 2.0 ppmvd NOx, corrected to 15 percent O_2.

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[47] SJVAPCD. BACT Clearinghouse, http://www.valleyair.org/busind/pto/bact/bactchidx.htm.
[48] SCAQMD. BACT Guidelines, http://www.aqmd.gov/bact/BACTGuidelines.htm.
[49] ARB. Statewide BACT, http://www.arb.ca.gov/bact/bact.htm.
[50] USEPA. RBLC, http://cfpub.epa.gov/rblc/htm/bl02.cfm.

Annual average NOx 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 NOx level, corrected to 15 percent O_2. The SJVAPCD BACT Guideline determination for NOx from gas turbines is shown in Appendix 6.2-4.

BACT for NOx emissions from the auxiliary boiler will be the use of low NOx emitting equipment and add-on controls. The Project has selected a boiler equipped with low-NOx burners. The boiler with low NOx burners will generate approximately 9 ppmvd NOx, corrected to 3 percent O_2. The SJVAPCD BACT guidelines indicated that BACT from a boiler (> 20 MMBtu/hr heat input) is a NOx exhaust concentration not to exceed 9 ppmvd, corrected to 3 percent O_2; therefore, the Project will meet the BACT requirements for NOx. The SJVAPCD BACT Guideline determination for NOx from boilers is shown in Appendix 6.2-4.

BACT for NOx emissions from the emergency standby generator engine is an emission factor of 1.0 g/bhp-hr, based on SJVAPCD BACT Guideline 3.1.8*. The Project has selected a Caterpillar G3512LE generator engine rated at 860 hp that has a NOx emission factor of 1.0 g/bhp-hr using a catalytic control system.

BACT for NOx emissions from the emergency standby fire water pump engine is an emission factor of 6.9 g/bhp-hr, based on SJVAPCD BACT Guidelines 3.1.2* and 3.1.4*. The Project has selected a fire water pump engine having a NOx emission factor less than 6.9 g/bhp-hr. Therefore, the Project emergency standby fire water pump engine will meet the BACT requirements for NOx.

<u>CO BACT</u> – BACT for CO emissions will be achieved by use of gas turbines equipped with dry low-NOx combustors and an oxidation catalyst. Dry low-NOx combustors emit low levels of combustion CO while still maintaining low-NOx formation. In addition, the Project will use an oxidation catalyst system to further reduce CO emissions to 4.0 ppmvd, corrected to 15 percent O_2. The Applicant has specified a CO limit of 4.0 ppmvd, corrected to 15 percent O_2. 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. The CO emission rate from the gas turbine at the outlet of the exhaust stacks will not exceed 4.0 ppmvd, corrected to 15 percent O_2, except under startup and shutdown conditions. A review of recent BACT determinations for CO from gas turbines is provided in Appendix 6.2-4.

BACT for CO emissions will be achieved by use of an auxiliary boiler equipped with low-NOx burners to 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-NOx combustors. As in the case of CO emission formation, dry low-NOx combustors use air to fuel ratios that result in low combustion VOC while still maintaining low NOx levels. BACT for VOC emissions from combustion devices has historically been the use of best combustion practices. With the use of the dry low-NOx 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 good combustion practices and an oxidation catalyst. The VOC emissions will be 2.0 ppmvd, corrected to 3 percent O_2. SJVAPCD BACT Guideline 1.1.2 indicates that VOC BACT for boilers (> 20 MMBtu/hr) is natural gas fuel and good combustion practices. The low NOx burners are designed to minimize incomplete combustion and therefore minimize VOC emissions.

PM_{10} BACT – For the turbines, duct burners and auxiliary boiler, BACT for PM_{10} is best combustion practices and the use of natural gas fuel, which will result in minimal particulate emissions.

SO_2 BACT – SO_2 emissions will be kept at a minimum by firing clean burning natural gas fuel with an average sulfur content of 0.36 gr/100 scf. The PG&E pipeline gas tariff limit/maximum sulfur content is 1.00 gr/100 scf.

In addition to the BACT requirements, SJVAPCD Rule 2201 requires the Project to provide full emission offsets when emissions exceed specified levels on a pollutant-specific basis. Offsets for CO are not required because this 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 6.2-31). As shown in Table 6.2-38, the Project would provide emission offsets for NOx, PM_{10}, and VOC emissions.

TABLE 6.2-38
SJVAPCD OFFSET REQUIREMENTS AND PROJECT EMISSIONS

Pollutant	Offset Threshold (lbs/yr)	Project Emission Rate[a] (lbs/yr)	Offsets Required
VOC	20,000	69,196	Yes
NOx	20,000	288,360	Yes
PM_{10}	29,200	161,320	Yes
SO_2	54,750	32,680	No

Notes:
[a] From Table 6.2-24, excluding emergency equipment, which is exempt from offsets under Section 4.6.2 of SJVAPCD Rule 2201.

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.

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 6.2.5.1 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} 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. The modeling results summarized in Table 6.2-34 show that the 24-hour and annual PM_{10} impacts from the Project will be below the applicable significance levels of 5 and 1 $\mu g/m^3$, respectively, so even in the absence of offsets the Project will not have a significant PM_{10} impact.

Emissions offset requirements for NOx, VOC, and PM_{10} are shown in Table 6.2-39 below, along with the quantity of credits currently held in the SJVAPCD Emission Reduction Credit Registry and the quantity of credits currently owned by the Applicant. Sufficient offsets are available through the SJVAPCD offset emissions bank and through sources that have not banked emissions with the SJVAPCD, such as facility closures. The SJVAPCD offset bank listing

TABE 6.2-39
FACILITY OFFSET REQUIREMENTS[a]

Pollutant	Facility Emissions [b] (lbs/yr)	Total Credits in SJVAPCD Registry [c] (lbs/yr)	Total Credits Currently Owned by Applicant (lbs/yr)
NOx	288,360	12,276,929	106,306
VOC	69,196	13,809,169	625,797
PM_{10}	161,320	2,587,784	4,520 and 403,203 SOx ERCs [d]

Notes:
[a] Offsets generally must be provided on a quarterly basis. See Appendix 6.2-5.
[b] From Table 6.2-40.
[c] SJVAPCD ERC Bank as of 5:13 AM, December 8, 2007.
[d] SOx ERCs will be used to satisfy PM_{10} offset requirement at an interpollutant conversion ratio of 1.4:1.

provides the required information for offset identification and assessment of the emission reduction levels achieved. The information includes the following:

- Ownership of emission offset sources; and
- ERCs granted by the SJVAPCD that have been determined to meet the District's requirements for bankable offsets.

A current listing of credits currently owned by the Applicant, as well as a quarterly reconciliation of offset requirements and ERCs, is included in Appendix 6.2-5. The Applicant may change the detailed structure of the proposed ERC package, and will notify the Commission of any such changes. The required ERC package will be acquired in time to satisfy the offset regulatory requirements of both the CEC and the District.

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 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)**.** Monitoring of fuel, limitations on the emissions of NOx, PM, and SO_2, source testing of stack emissions, process monitoring, and data collection and recordkeeping are required by one or more of the following applicable NSPS:

- Subpart KKKK (Standards of Performance for Stationary Gas Turbines [constructed after February 18, 2005])
- Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)
- Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
- Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

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 4002 (National Emissions Standards for Hazardous Air Pollutants). The requirements of this rule do not apply to the Project because total HAP emissions are less than 25 tons per year and individual HAP emissions are less than 10 tons per year.

Rule 4101 (Visible Emissions). Any visible emissions from the Project will not be darker than No. 1 when compared to a Ringelmann Chart for any period(s) aggregating 3 minutes in any hour. Because the facility will burn natural gas, except for the Diesel fuel burned in testing the emergency standby fire water pump engine, the opacity standard of not greater than 20 percent for a period or periods aggregating 3 minutes in any hour.

Rule 4102 (Public Nuisance). The facility would not emit quantities of odorous or visible substances sufficient to cause a nuisance; 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 rule limit. The maximum grain loading for the turbines and duct burners (from Table 6.2-1.1, Appendix 6.2-1) is 0.0023 gr/dscf, well below the 0.1 gr/dscf limit of the rule. Tables 6.2-1.3 and 6.2-1.4 show that the particulate grain loadings for the emergency standby generator and fire water pump engines are 0.0037 and 0.0073 gr/scf, respectively, also well below the limit of the rule.

Rule 4301 (Fuel Burning Equipment). Applies only to the auxiliary boiler, which would emit rule regulated-pollutants at levels less than the following rule limits:

- "Combustion contaminant emissions": 0.1 grain per dry standard cubic foot @ 12% CO_2 and 10 pounds per hour
- Sulfur compounds as SO_2: 200 pounds per hour
- NOx as NO_2 to 140 pounds per hour

Rule 4305 (Boilers, SteamGenerators, and Process Heaters Phase 2**).** Applies only to the auxiliary boiler, which would emit gas-fired NOx at 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), which is less than the rule limit of 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu), and CO at 50 ppmvd @ 3% O_2, which is less than the rule limit of 400 ppmvd @ 3% O_2.

Rule 4306 (Boilers, SteamGenerators, and Process Heaters Phase 3**).** Applies only to the auxiliary boiler, which would be classified as a Category H boiler, and would emit gas-fired NOx at 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), which is less than the rule limit of 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu). The boiler would include the required installation of CEMs for NOx, CO and O_2.

Rule 4351 (Boilers, SteamGenerators, and Process Heaters Phase 1**).** Applies only to the auxiliary boiler, which would emit gas-fired NOx at 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), which is less than the rule limit of 90 ppmvd @ 3% O_2 (0.10 lb/MMBtu), and CO at 50 ppmvd @ 3% O_2, which is less than the rule limit of 400 ppmvd @ 3% O_2.

Rule 4701 (Internal Combustion Engines). The emergency standby generator and fire water pump engines are exempt from the requirements pursuant to rule Sections 4.2.1 (standby engines) and 4.2.2 (engines used exclusively for fire fighting services and flood control), except for the administrative requirements of Sections 6.1, 6.2.2, and 6.2.3. The information required by Section 6.1 is provided in this AFC; the recordkeeping requirements of Sections 6.2.2 and 6.2.3 are expected to be imposed as permit conditions.

Rule 4703 (Stationary Gas Turbines). Emissions from the new turbine of 2 ppmvd NOx and 4 ppmvd CO, both @15% O_2 would be below the rule limits of 3 ppmvd NOx and 25 ppmvd CO, both @15% O_2.

Rule 4801 (Sulfur Compound Emissions). The Project would emit the following SO_2 levels, which are far less than the Rule 4801 2,000 ppmv limit:

- Turbines: 0.14 ppmvd @15% O_2
- Auxiliary boiler: 1.7 ppmvd @3% O_2
- Emergency standby generator engine: 1.2 ppmv @8.5% O_2
- Emergency standby fire water pump engine: 0.51 ppmv

Rule 8011 (Fugitive PM_{10} Prohibitions, General Requirements). The Project would adhere to this rule's requirements and fees related to the control of PM_{10}.

Rule 8021 (Fugitive PM_{10} Prohibitions, Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities). The Project would submit a Dust Control Plan prior to the commencement of construction, and use the specified control measures to control fugitive dust emissions during construction.

Rule 8041 (Carryout and Trackout [Fugitive PM_{10} Prohibitions). The Project would implement the specific measures required to minimize fugitive dust emissions from construction carryout and trackout.

Rule 8051 (Open Areas [Fugitive PM_{10} Prohibitions). The Project would implement the specific measures required to minimize fugitive dust emissions from open areas larger than 3.0 acres that contain more than 1,000 square feet of disturbed surface.

Rule 8061 (Paved and Unpaved Roads [Fugitive PM_{10} Prohibitions). The Project would implement the specific measures required to minimize fugitive dust emissions from constructed onsite paved and unpaved roads.

Rule 8071 (Unpaved Vehicle/Equipment Traffic Areas [Fugitive PM_{10} Prohibitions)**.** The Project would not need to implement these rule-specific measures required to minimize fugitive dust emissions because the Project would not experience more than 50 annual average daily trips.

6.2.7 CUMULATIVE AIR QUALITY IMPACT ANALYSIS

This section discusses potential cumulative air quality impacts for the Project's emissions of criteria pollutants and greenhouse gases separately.

6.2.7.1 Criteria Pollutant Cumulative Impact Analysis

Cumulative air quality impacts from the Project and other reasonably foreseeable projects would be both regional and localized in nature. Regional air quality impacts are possible for pollutants such as ozone, which is formed through a photochemical process that can take hours to occur. Carbon monoxide, NO_2, and SO_2 impacts are generally localized in the area in which they are emitted. PM_{10} can create a local air quality problem in the vicinity of its emission source. Along with $PM_{2.5,}$ PM_{10} can also be a regional issue when both of these criteria pollutants are formed in the atmosphere from VOC, SOx, and NOx.

The cumulative impacts analysis, if needed, would consider the potential for both regional and localized impacts due to emissions from the Project. Regional impacts will be evaluated by comparing maximum daily and annual emissions from the Project with emissions of ozone and PM_{10} precursors in the San Joaquin Valley Air Basin. Localized impacts will be evaluated by looking at other local sources of pollutants that are not included in the background air quality data to determine whether these sources in combination with the Project would be expected to cause significant cumulative air quality impacts.

6.2.7.1.1 *Regional Impacts*

Regional impacts are evaluated by assessing the Project's contribution to regional emissions. Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region and from day to day, state law requires reductions in emissions of both precursors to reduce overall ozone levels. The change in the sum of emissions of these pollutants, equally weighted, provides a rough estimate of the impact of the Project on regional ozone levels. Similarly, a comparison of the emissions of PM_{10} and $PM_{2.5}$ precursor emissions from the Project with regional PM_{10} and $PM_{2.5}$ precursor emissions provides an estimate of the impact of the Project on regional PM_{10} and $PM_{2.5}$ levels.

Table 6.2-40 summarizes these comparisons. The Project's emissions are compared with regional emissions in 2010, when construction of the proposed project is expected to begin. San Joaquin Valley Air Basin emissions projections for 2010 were taken from the Air Resources Board's web-based emission inventory projection software.[51]

[51] ARB. *www.arb.ca.gov/app/emsinv/emssumcat.php*

TABLE 6.2-40
COMPARISON OF PROJECT EMISSIONS TO REGIONAL PRECURSOR EMISSIONS IN 2010: ANNUAL BASIS[a]

Ozone Precursors – Annual Basis	
Total San Joaquin Valley Air Basin Ozone Precursors, tons/year	330,654
Total Project Ozone Precursor Emissions [b], tons/year	179
Ratio of Project to Basin Ozone Precursor Emissions, %	0.05%
PM_{10} Precursors – Annual Basis	
Total San Joaquin Valley Air Basin PM_{10} Precursors, tons/year	446,687
Total Project PM_{10} Precursor Emissions [b], tons/year	276
Ratio of Project to Basin PM_{10} Precursor Emissions, %	0.06%
$PM_{2.5}$ Precursors – Annual Basis	
Total San Joaquin Valley Air Basin $PM_{2.5}$ Precursors, tons/year	377,008
Total Project $PM_{2.5}$ Precursor Emissions [b], tons/year	276
Ratio of Project to Basin $PM_{2.5}$ Precursor Emissions, %	0.07%

Notes:
[a] Basin-wide emissions calculated as 365 times daily emissions.
[b] From Table 6.2-24

6.2.7.1.2 *Localized Impacts*

The CEC has defined this local analysis as "a cumulative air quality modeling impacts analysis of the project's typical operating mode in combination with other stationary source emissions sources within a six-mile radius which have received construction permits but are not yet operating, or are in the permitting process."[52] Within the distance of six miles, three categories of projects with combustion sources were evaluated:

- Existing projects that have been in operation since at least January 2006.
- Projects for which air pollution permits to construct have been issued and that began operation after 2006.
- Projects for which air pollution permits to construct have not been issued, but are reasonably foreseeable.

Existing projects that have been in operation since at least January 2006 are reflected in the ambient air quality data that have been used to represent background concentrations for the proposed project; consequently, no further analysis of the emissions from this category of facilities was performed.

[52] CEC. ATTACHMENT B - ENERGY COMMISSION STAFF'S DATA ADEQUACY WORKSHEET for Air Quality., Energy Facilities Siting Division, March 2007.

The District was requested on July 19, 2007, to provide information on any sources that might be appropriate (i.e., within 6 miles and with an emission increase of at least 5 tons per year for a criteria pollutant) for a cumulative air quality impact analysis, but has not identified any. Consequently, no localized cumulative impact modeling analysis was performed for the proposed project.

6.2.7.2 Greenhouse Gas Cumulative Impact Analysis

Greenhouse gas (GHG) emissions have received increasing attention; most significantly, in 2006 the Governor signed the California Global Warming Solutions Act of 2006. Combustion of natural gas in the Project's gas turbines, auxiliary boiler and emergency standby generator engine, and Diesel fuel combustion in the emergency standby fire water pump engine would result in the emissions of the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Leaks from Project electrical equipment (e.g., circuit breakers) would emit sulfur hexafluoride (SF_6). These GHG emissions from the Project would join the emissions of the same GHG from the combustion of fossil fuels from all sources (e.g., home natural gas heaters, coal-fired power plants).

As stated earlier, new efficient natural gas-fired combined-cycle generation reduces the GHG emissions accompanying the electricity produced to serve load. Power plants are dispatched according to their efficiency, and to provide grid support. Thus, if the Avenal Energy Project is operating, in most cases it would be at least as efficient, and most likely more efficient, than the power plant that would have been dispatched if the proposed power plant did not exist. Because higher efficiency means lower GHG emissions per unit of electric energy produced, when this Project operates it will at a minimum not increase the GHG emissions produced to generate the needed electricity, and could reduce the amount of emissions if displacing a higher heat rate facility. In addition, natural gas-fired generation will be needed to replace coal-based electric power generation as California transitions to a lower carbon profile for the electricity it consumes. Therefore, the GHG emissions from this facility will not have a direct significant impact on the environment.

GHG emissions for the proposed project are summarized in Table 6.2-41.

TABLE 6.2-41
PROJECT AND GLOBAL GHG EMISSIONS (MMT CO_2e/year)[a]

GHG	Project	Global	Project Portion (%)
CO_2	1.71	27,000	0.006
CH_4	0.0044	8,530	0.00005
N_2O	0.00096	4,800	0.00002
SF_6	0.000063 [b]	46.77 [c]	0.00013
Total =	1.71	40,377	0.004

Notes:
[a] Million metric tons of carbon dioxide equivalent.
[b] Based on three 230 kV circuit breakers, each holding 208 lbs SF_6, an Areva – T&D guaranteed leakage limit of 1%/yr, and IPCC (2001) global warming potential of 22,200.
[c] USEPA. *Global Anthropogenic Non-CO_2 Greenhouse Gas Emissions: 1990-2020,* June 2006 Revised.

The detailed GHG emission calculations for the Project are included in Appendix 6.2-1.

Because GHG emissions can affect climate change on only a global basis, and the proposed project's GHG emissions are not substantial compared to global emissions, the cumulative impact of the proposed project's GHG emissions is less than significant. The project's emissions would be subject to regulation pursuant to AB 32; through the implementation of this statute, any remaining cumulative impacts will be mitigated. Nonetheless, through the use of advanced, efficient generating technology for the production of electrical power, the proposed project reasonably minimizes GHG emissions associated with this type of activity.

6.2.8 MITIGATION

Mitigation for CEQA would be provided in the form of offsets for all criteria pollutant emission increases from the Project after the installation of BACT. The offset mitigation will be calculated to also satisfy SJVAPCD regulations, accounting for offset thresholds, distance ratios, and interpollutant conversion ratios. Because the cumulative air quality impacts analysis described above shows that the Project would not result in significant cumulative impacts, no additional mitigation beyond that required under SJVAPCD regulations would be necessary.

6.2.9 REFERENCES

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Figure 6.2-1
January Predominant Mean Circulation of the Surface Winds

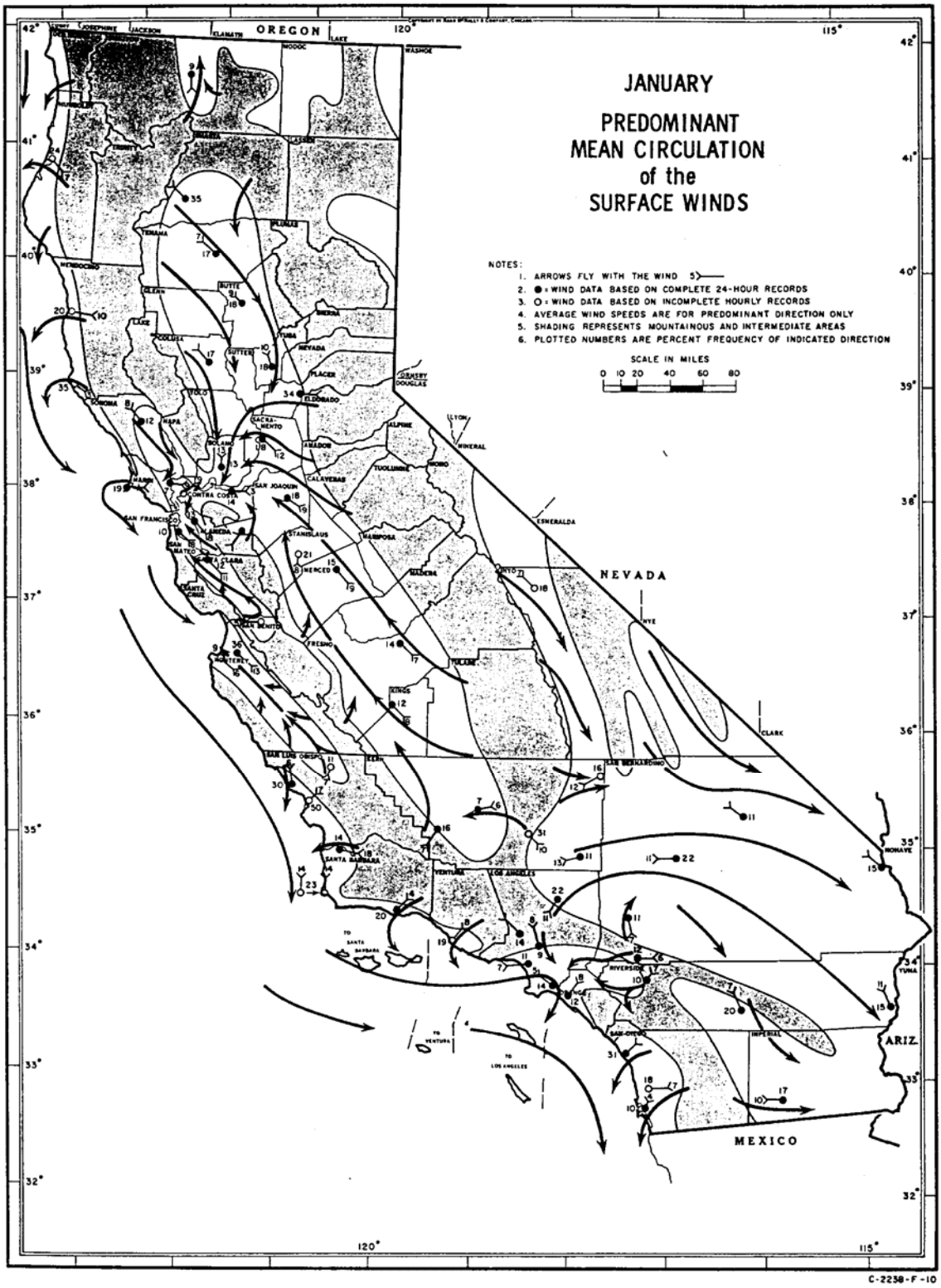


Figure 6.2-2
April Predominant Mean Circulation of the Surface Winds

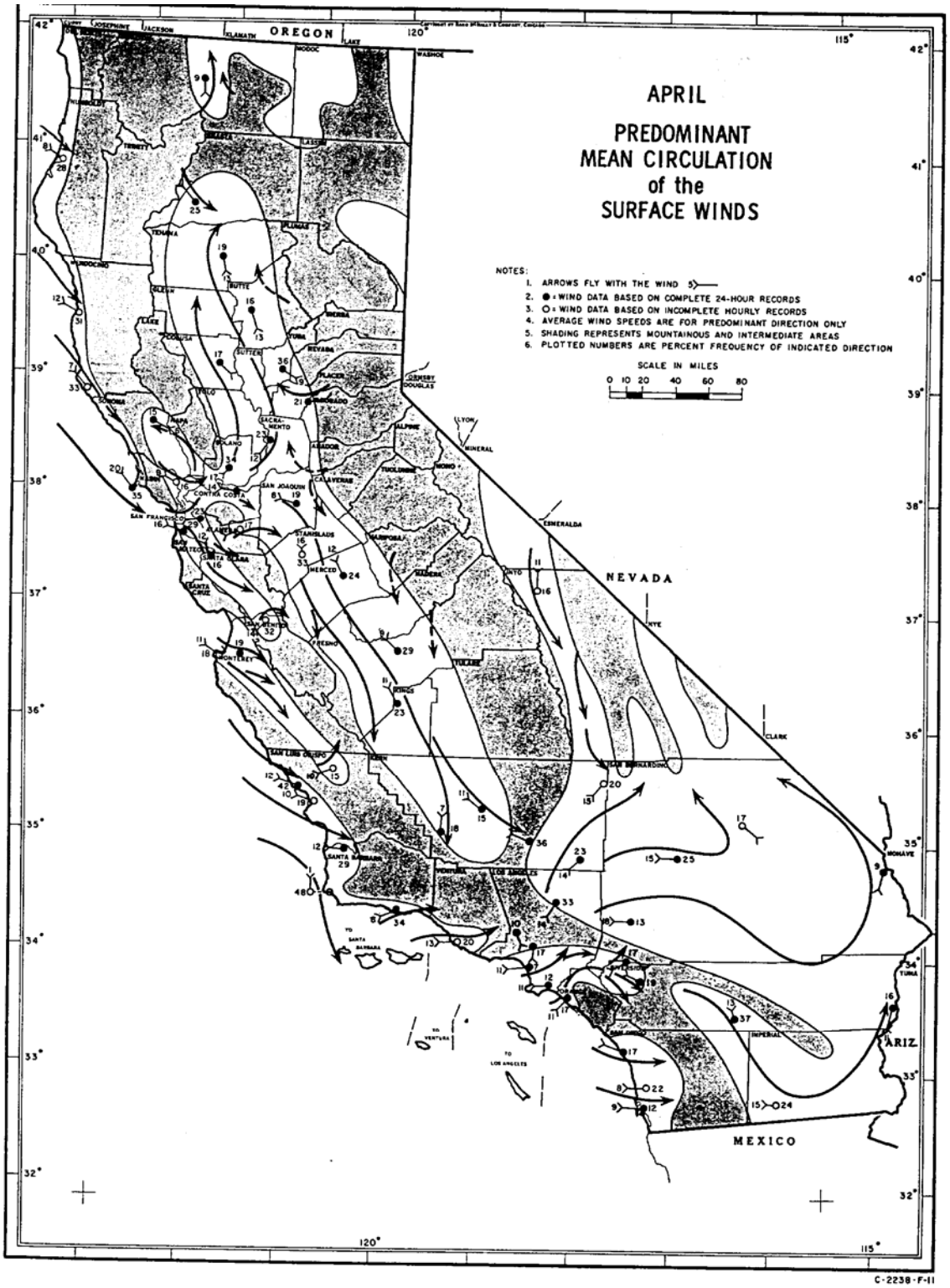


Figure 6.2-3
July Predominant Mean Circulation of the Surface Winds

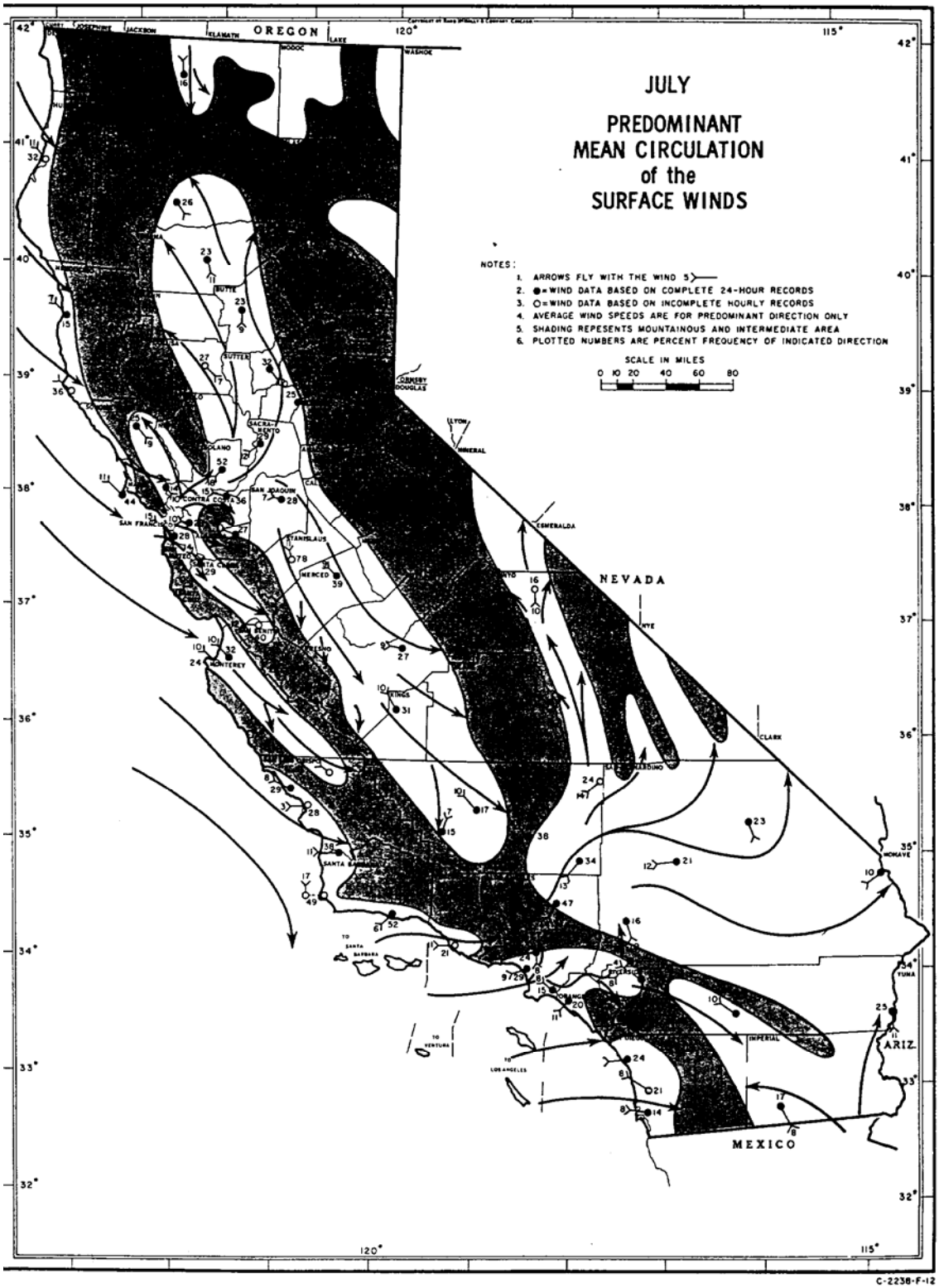


Figure 6.2-4
October Predominant Mean Circulation of the Surface Winds

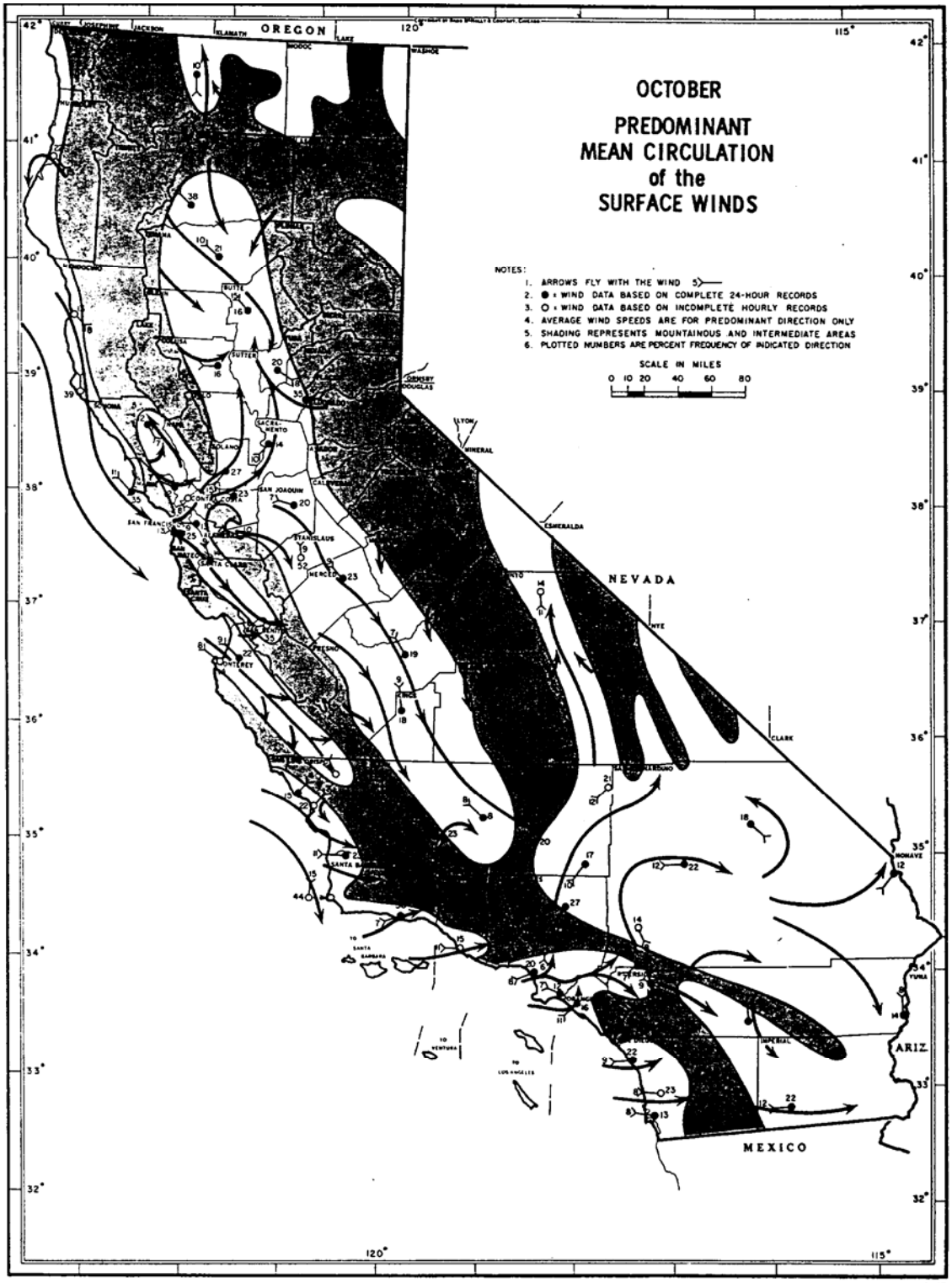


Figure 6.2-5a
Annual Wind Rose
Hanford, California
January 1, 2000 through December 31, 2000

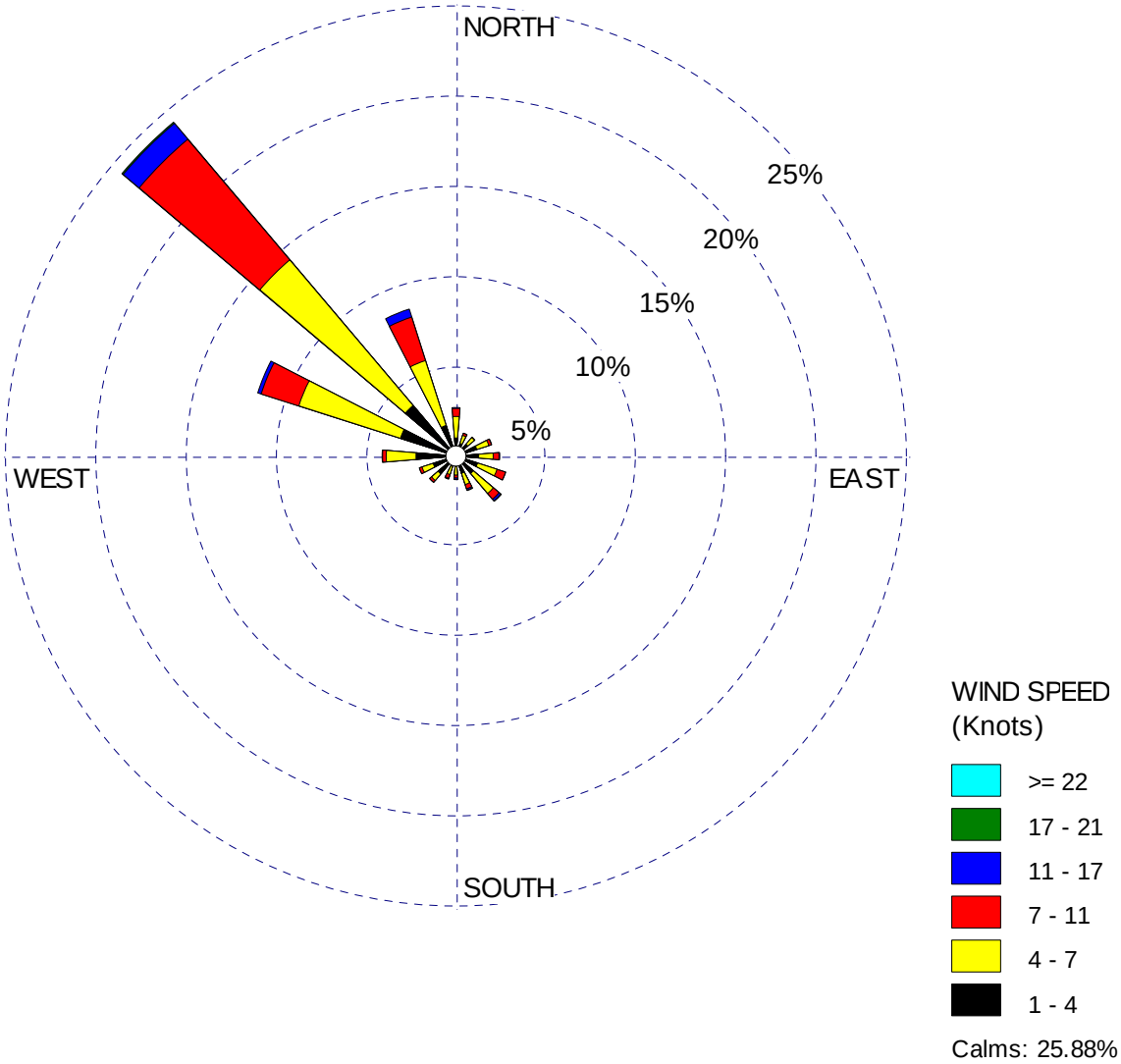


Figure 6.2-5b
First Quarter Wind Rose
Hanford, California
January 1, 2000 through March 31, 2000

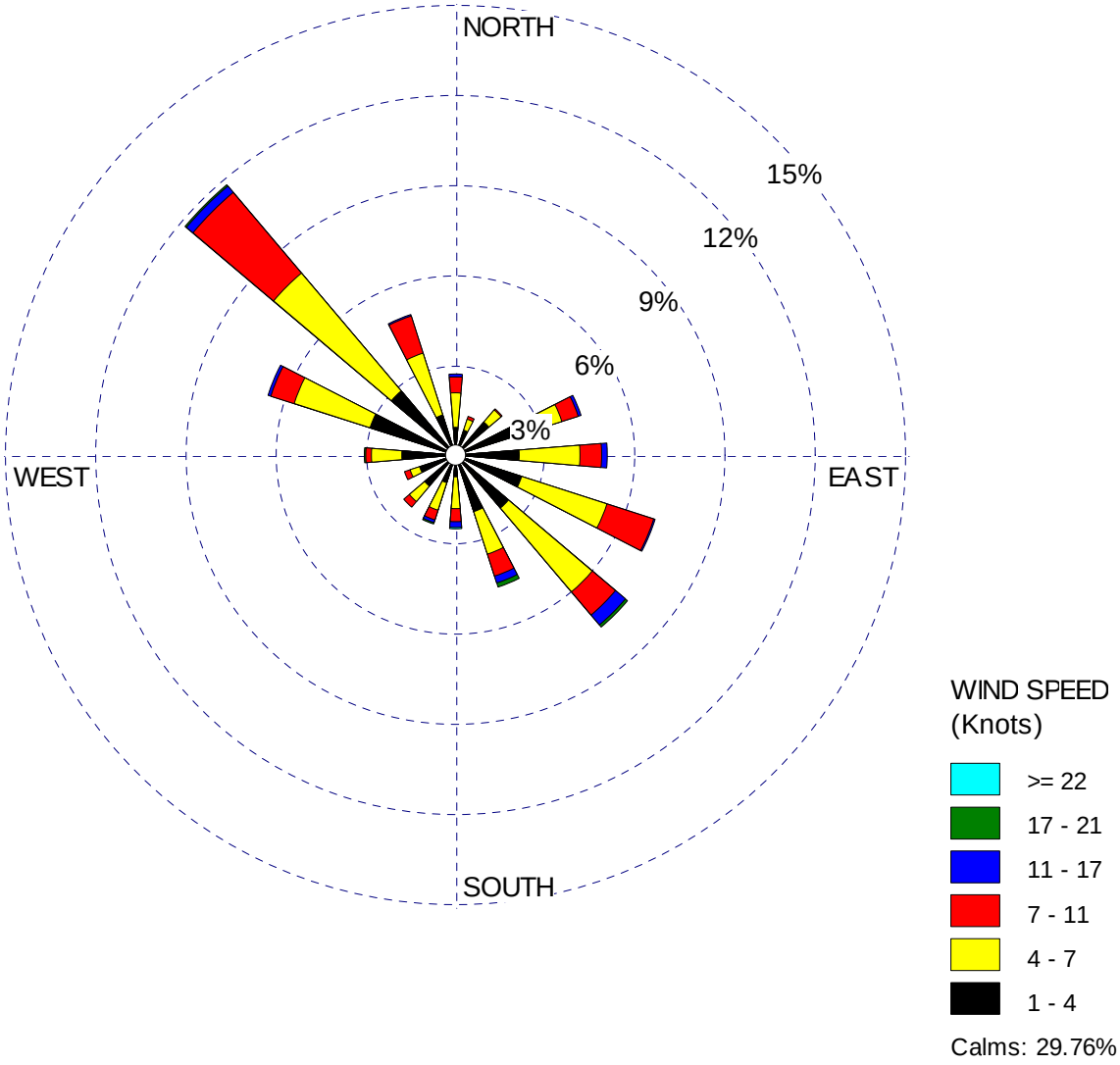


Figure 6.2-5c
Second Quarter Wind Rose
Hanford, California
April 1, 2000 through June 30, 2000

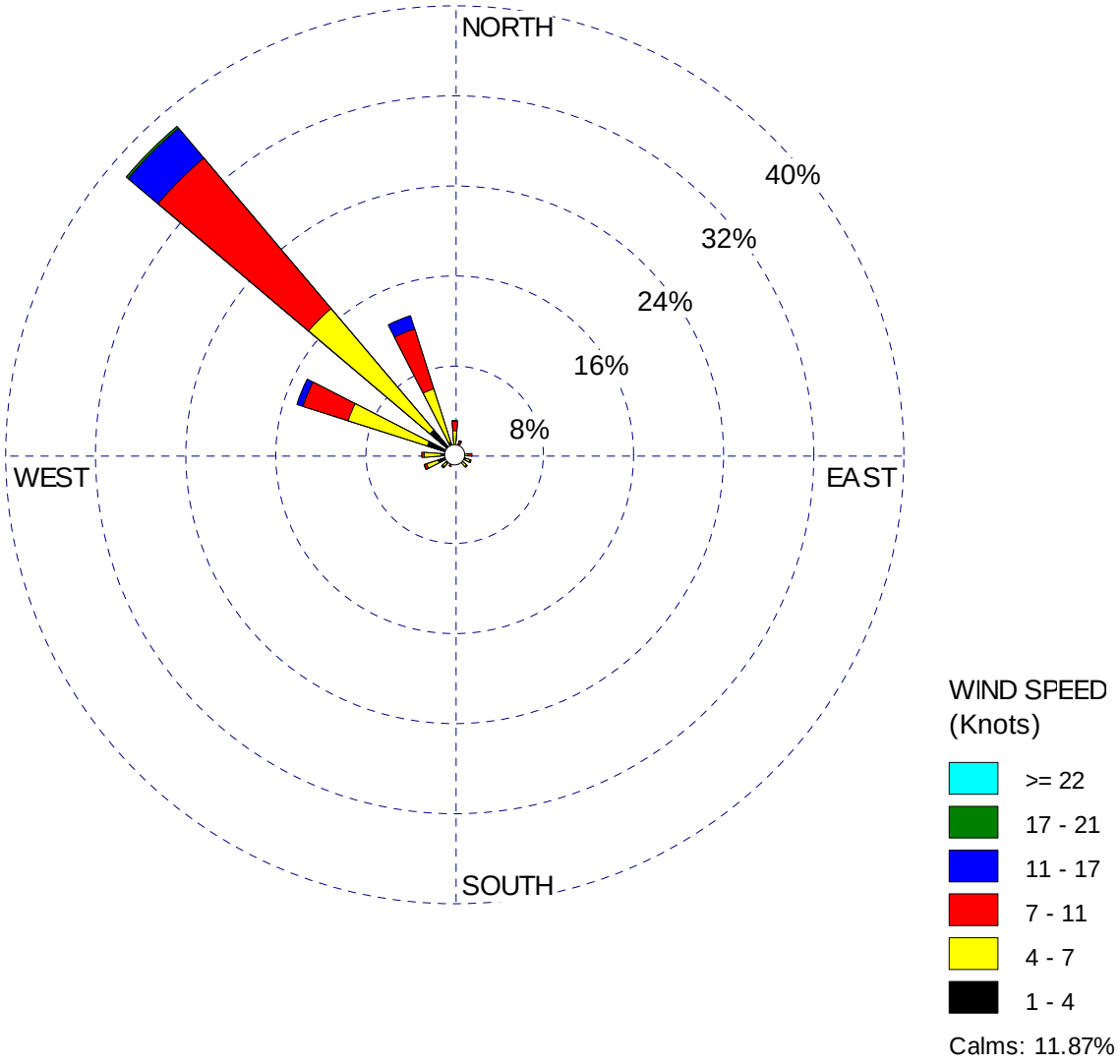


Figure 6.2-5d
Third Quarter Wind Rose
Hanford, California
July 1, 2000 through September 30, 2000

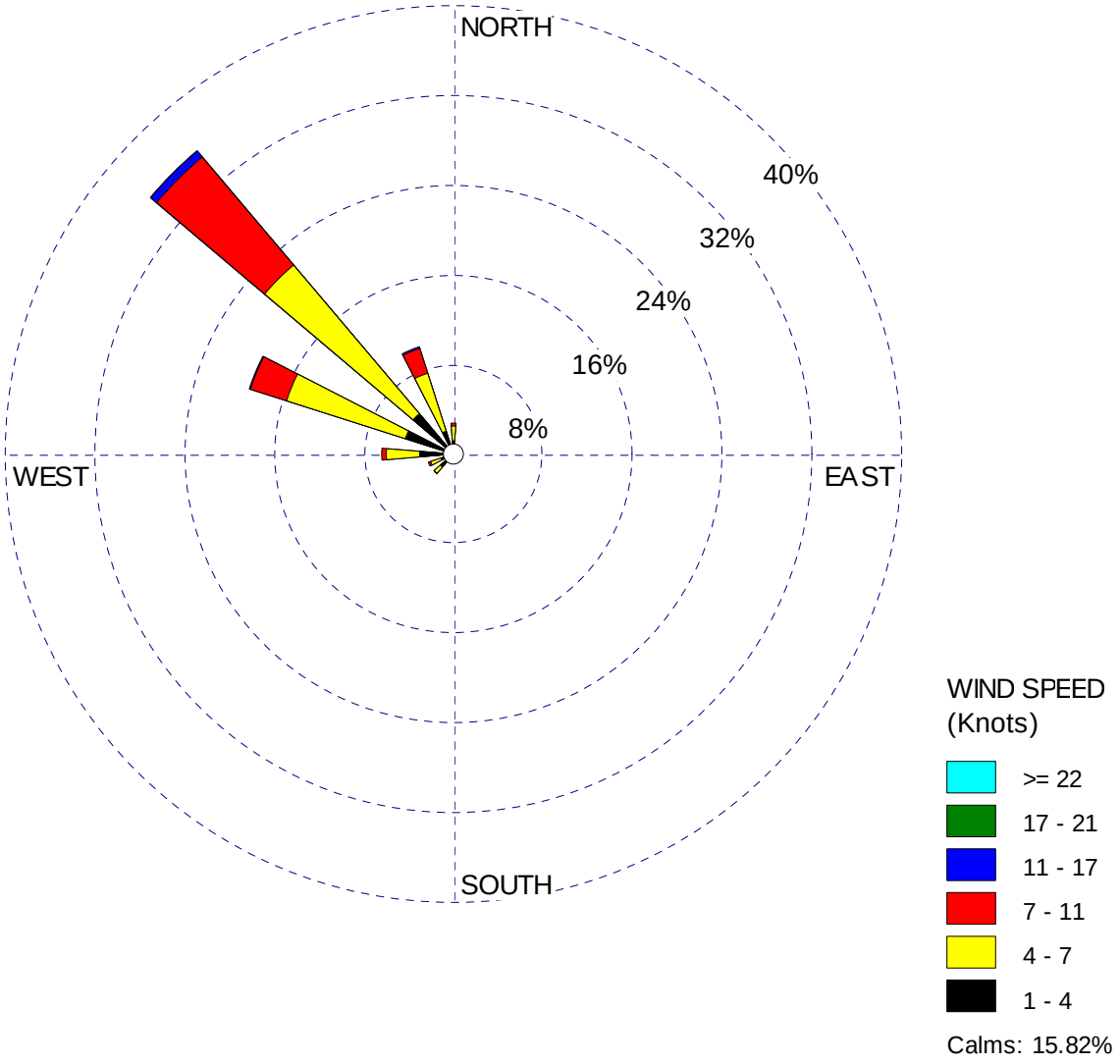


Figure 6.2-5e
Fourth Quarter Wind Rose
Hanford, California
October 1, 2000 through December 31, 2000

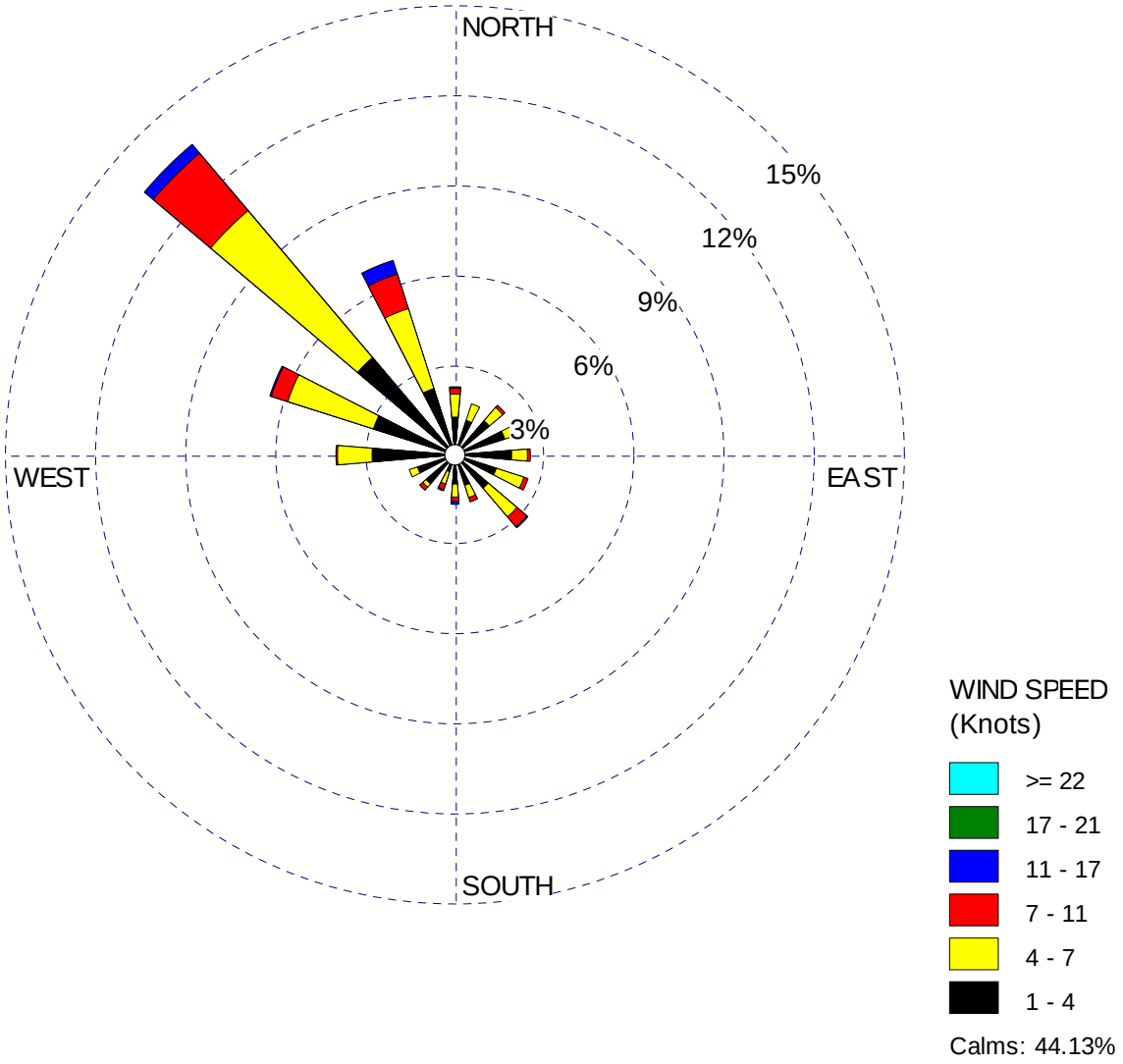


Figure 6.2-5f
Annual Wind Rose
Hanford, California
January 1, 2001 through December 31, 2001

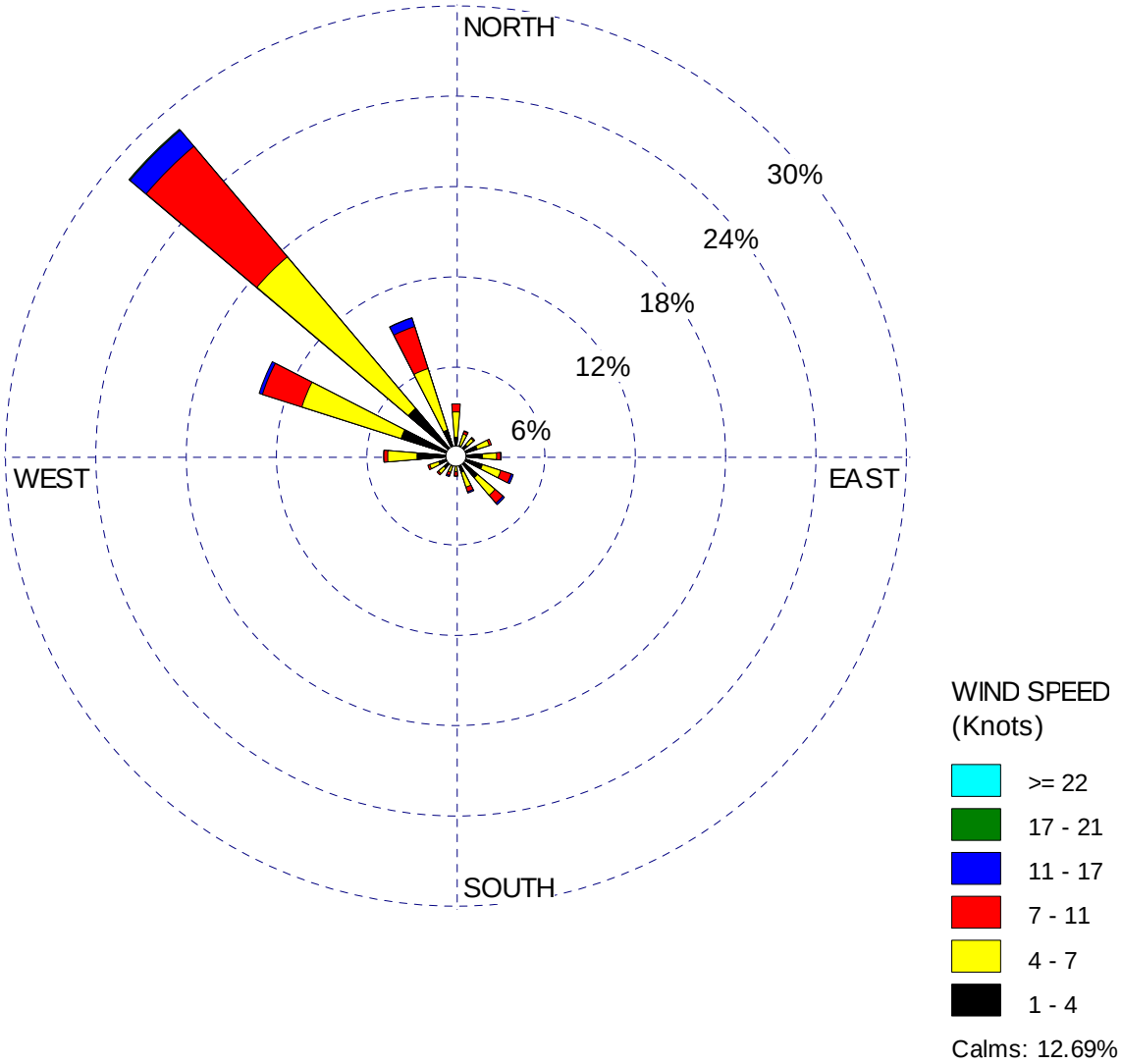


Figure 6.2-5g
First Quarter Wind Rose
Hanford, California
January 1, 2001 through March 31, 2001

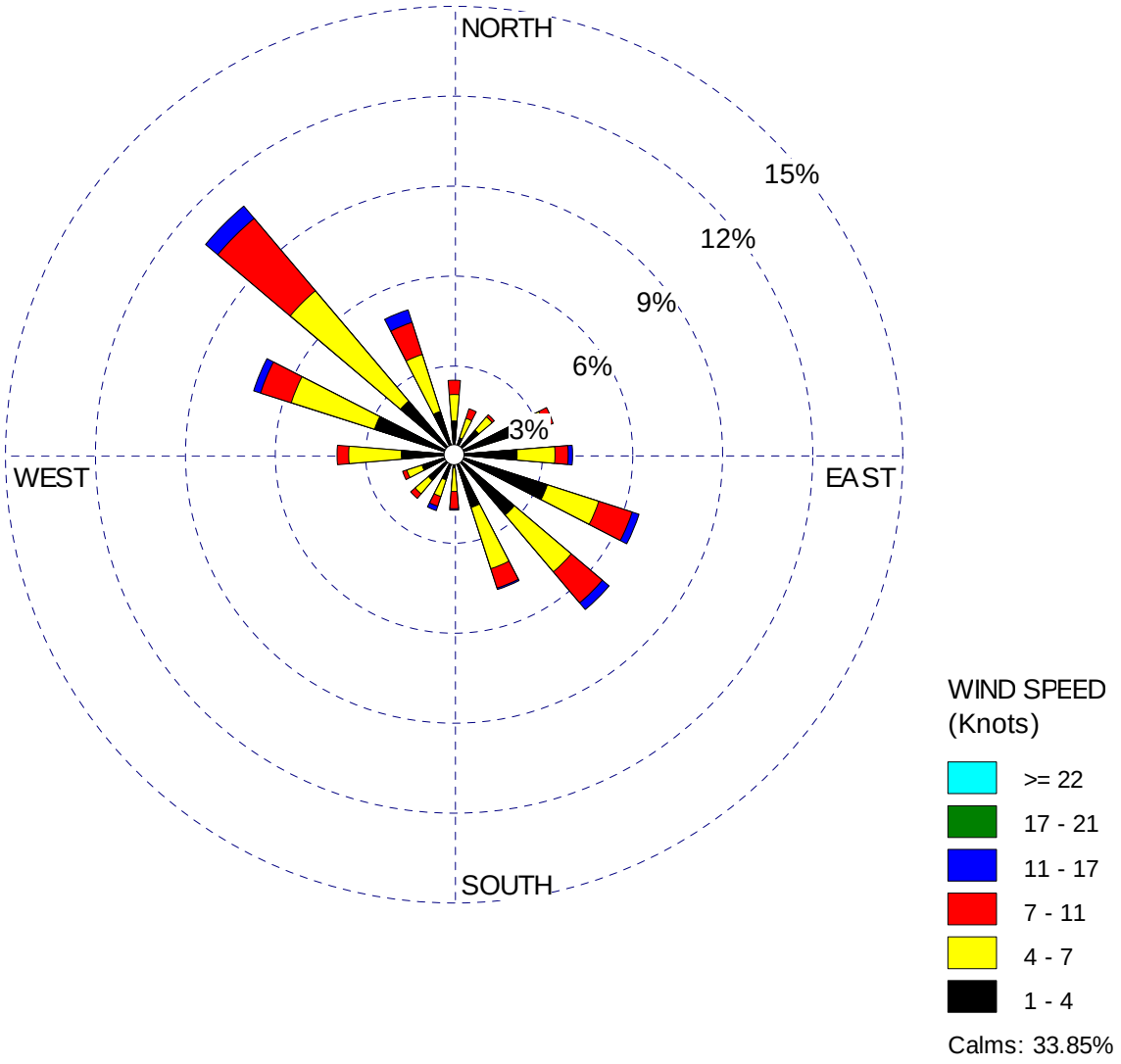


Figure 6.2-5h
Second Quarter Wind Rose
Hanford, California
April 1, 2001 through June 30, 2001

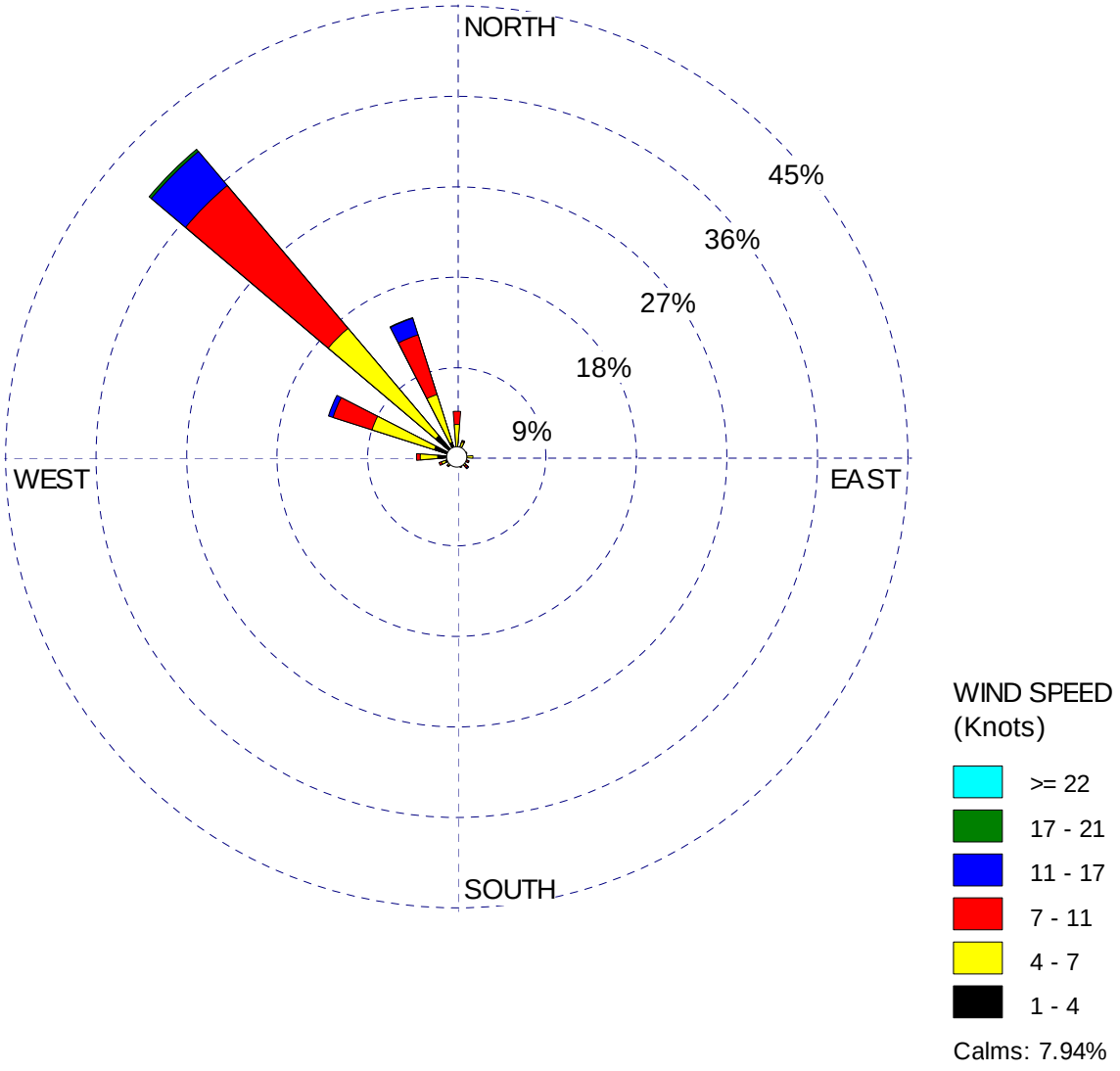


Figure 6.2-5i
Third Quarter Wind Rose
Hanford, California
July 1, 2001 through September 30, 2001

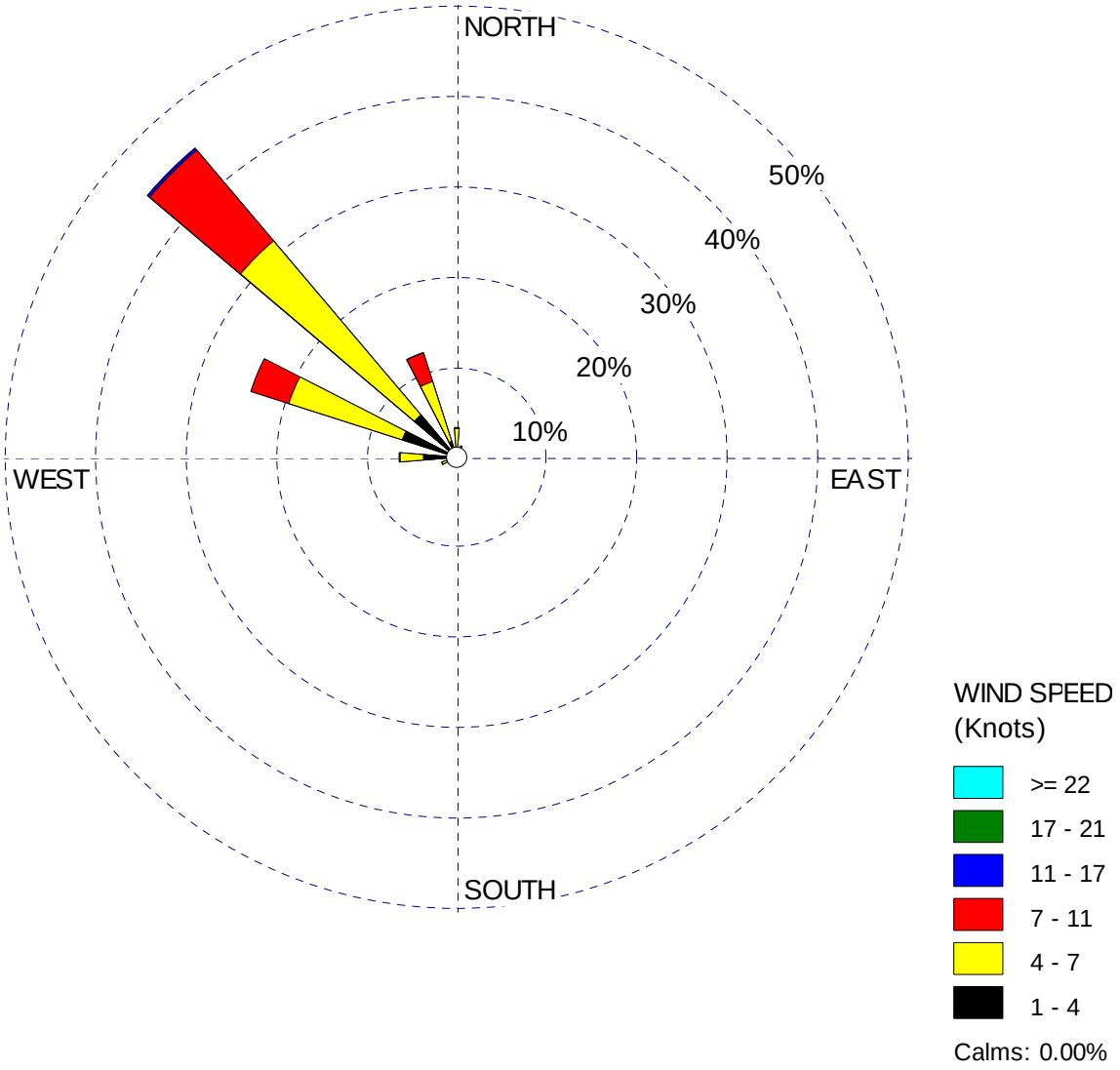


Figure 6.2-5j
Fourth Quarter Wind Rose
Hanford, California
October 1, 2001 through December 31, 2001

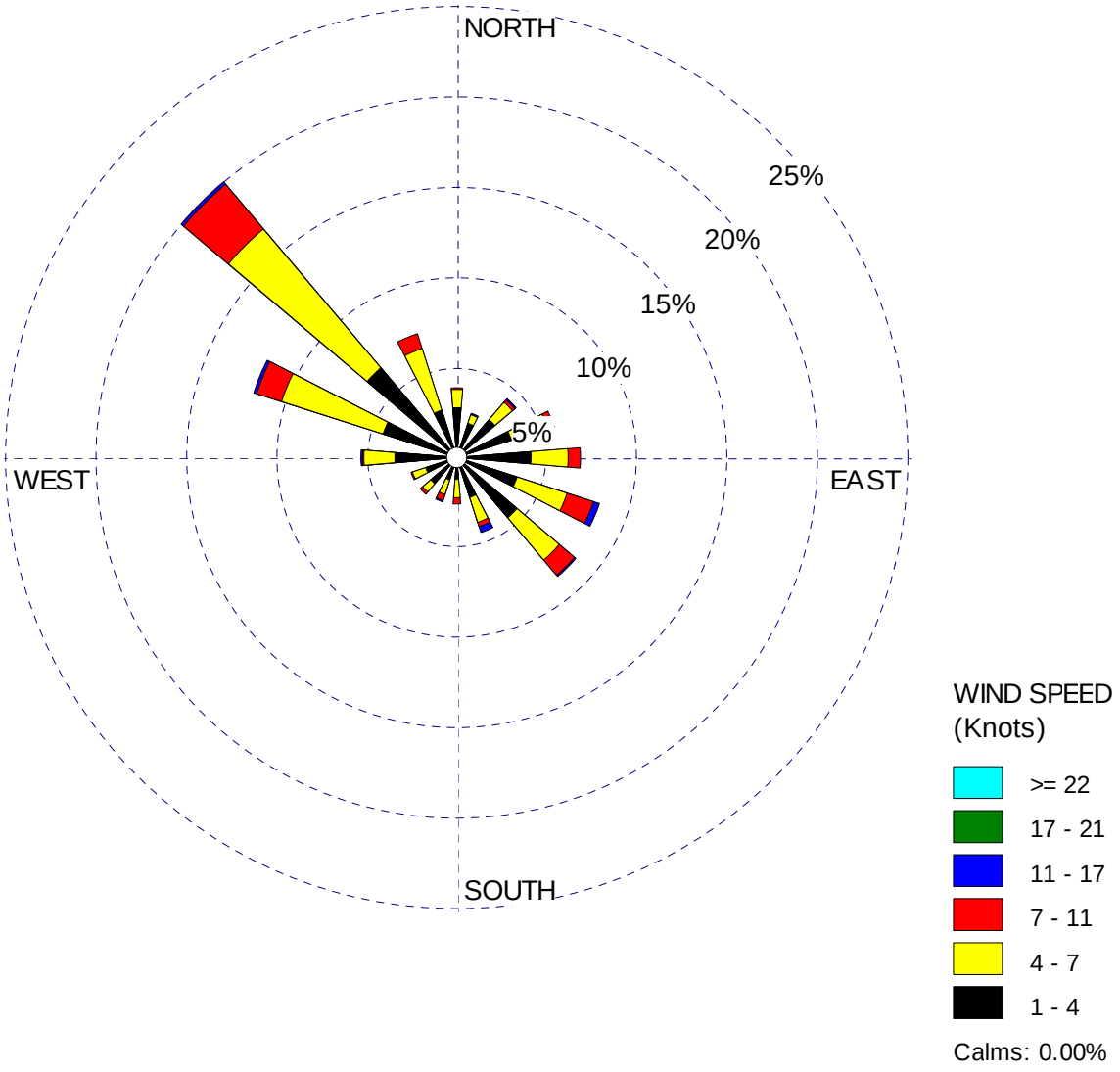


Figure 6.2-5k
Annual Wind Rose
Hanford, California
January 1, 2002 through December 31, 2002

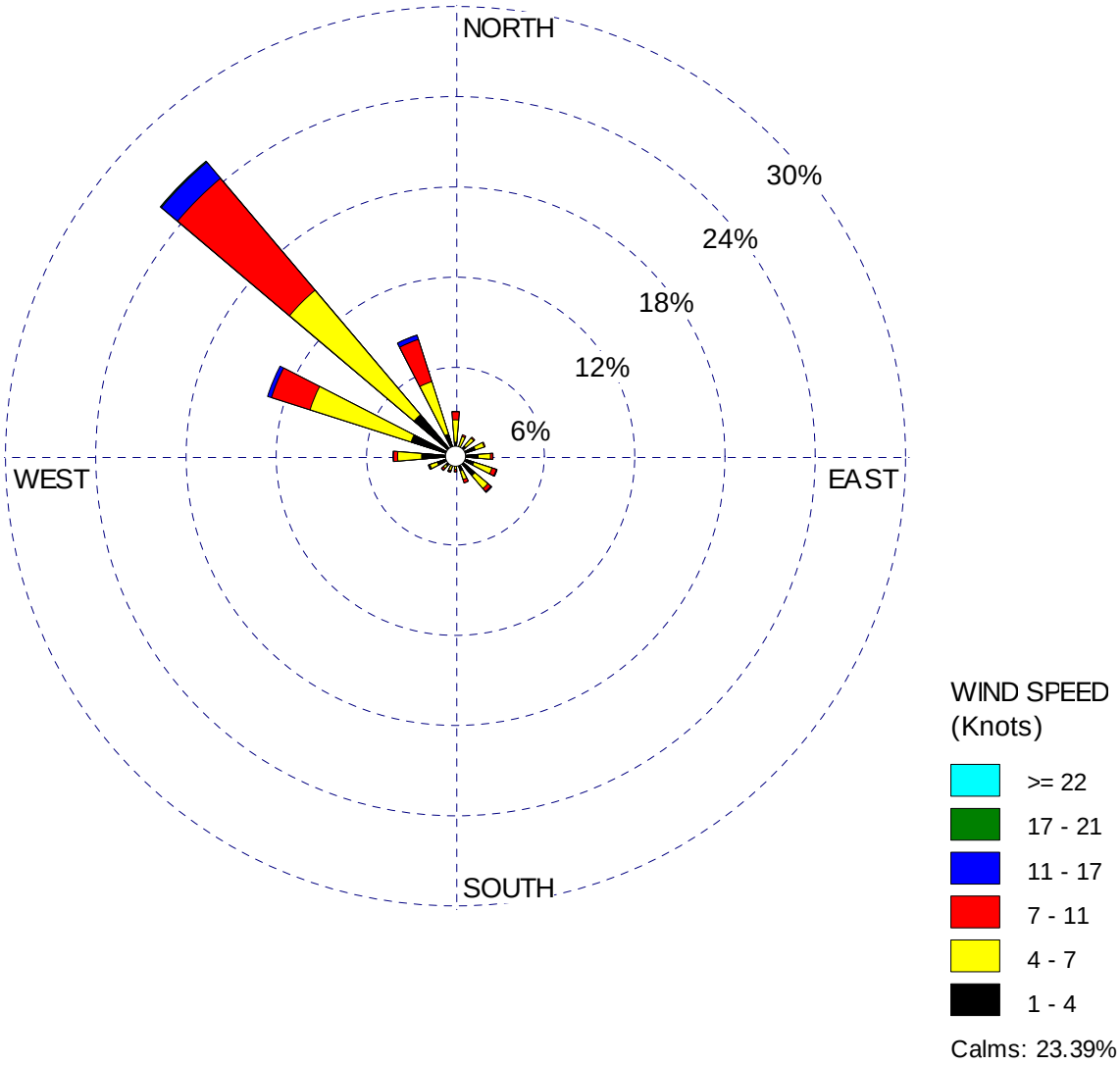


Figure 6.2-5l
First Quarter Wind Rose
Hanford, California
January 1, 2002 through March 31, 2002

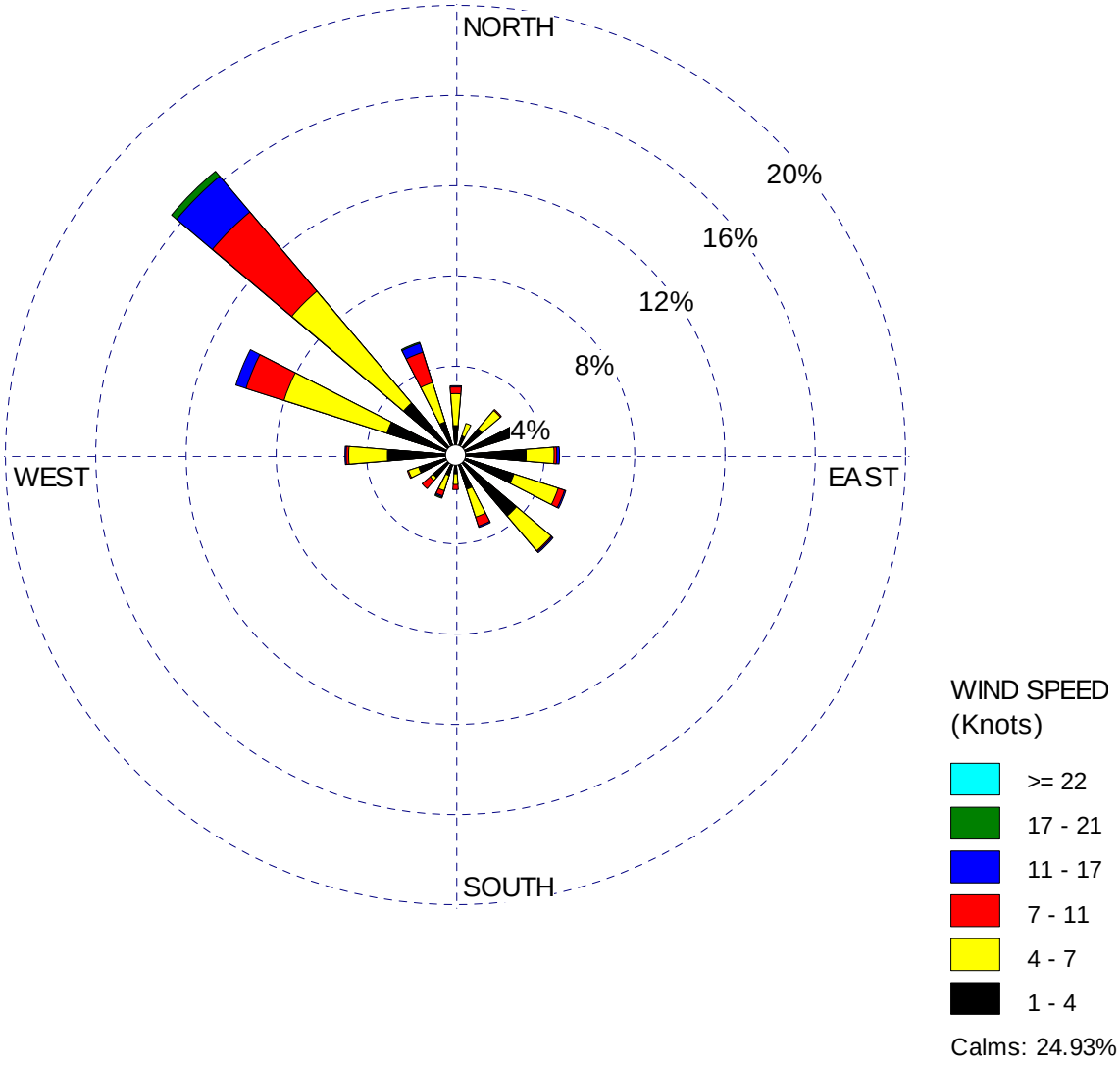
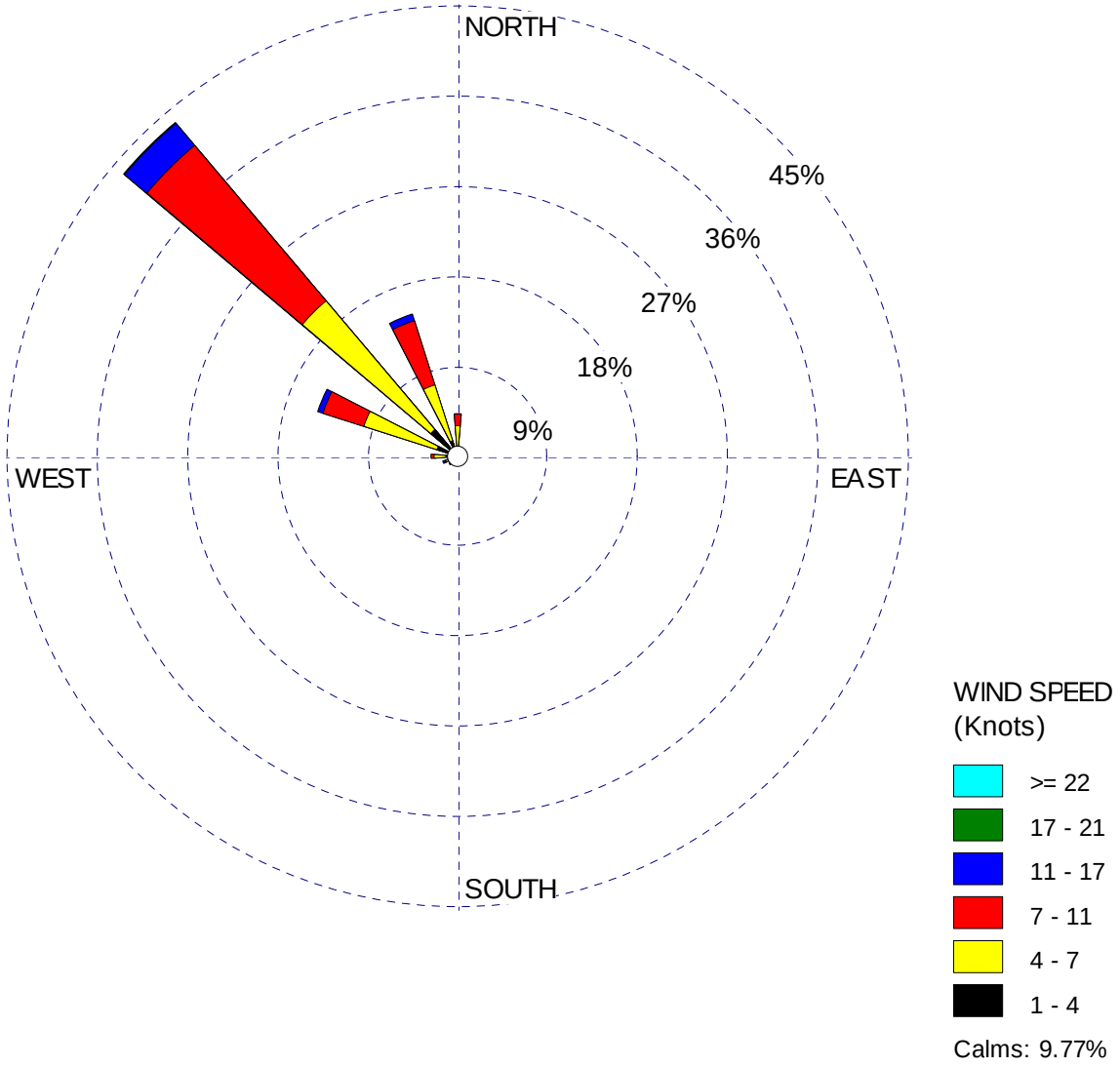


Figure 6.2-5m
Second Quarter Wind Rose
Hanford, California
April 1, 2002 through June 30, 2002



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Third Quarter Wind Rose
Hanford, California
July 1, 2002 through September 30, 2002

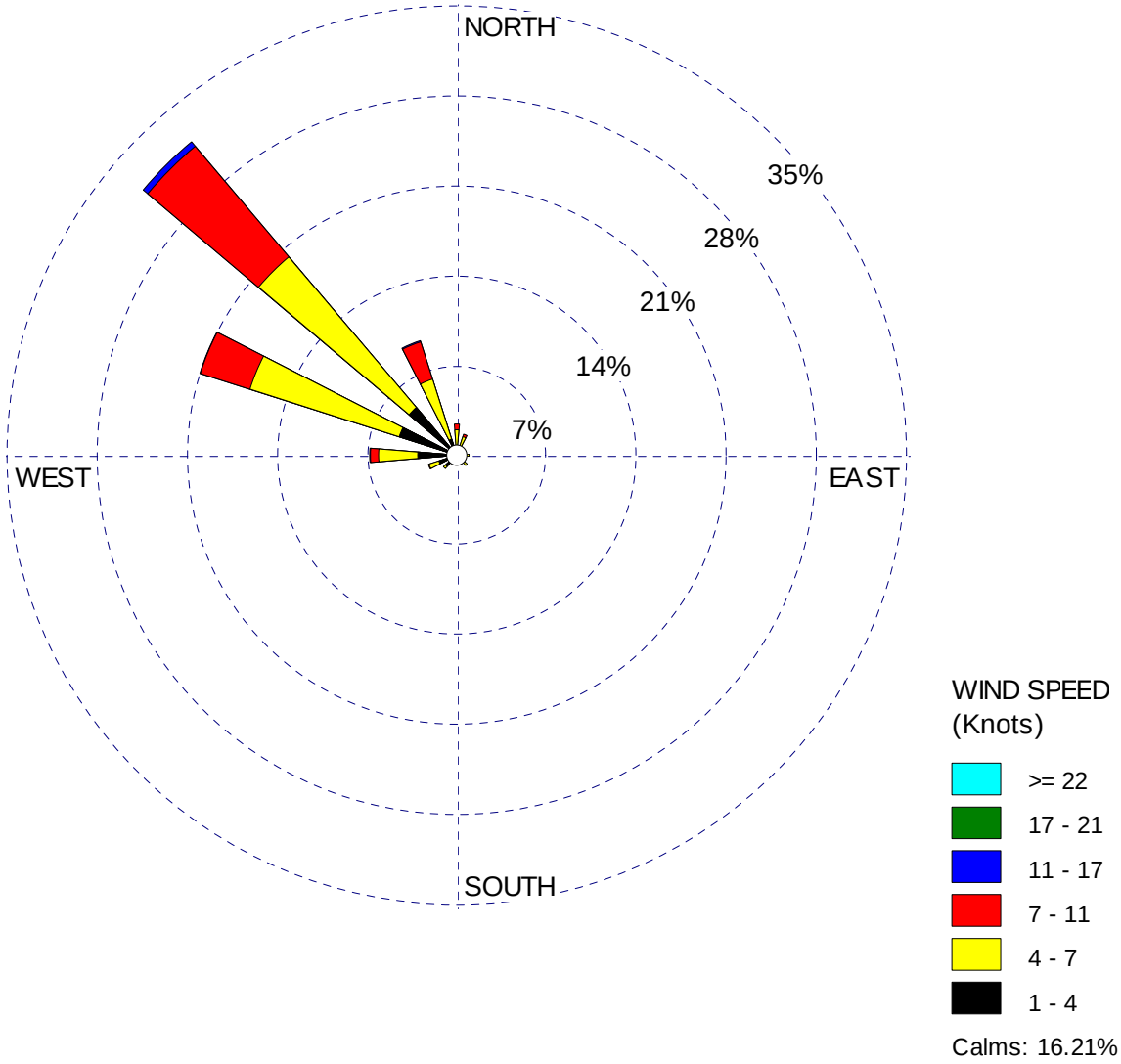

Figure 6.2-5o
Fourth Quarter Wind Rose
Hanford, California
October 1, 2002 through December 31, 2002

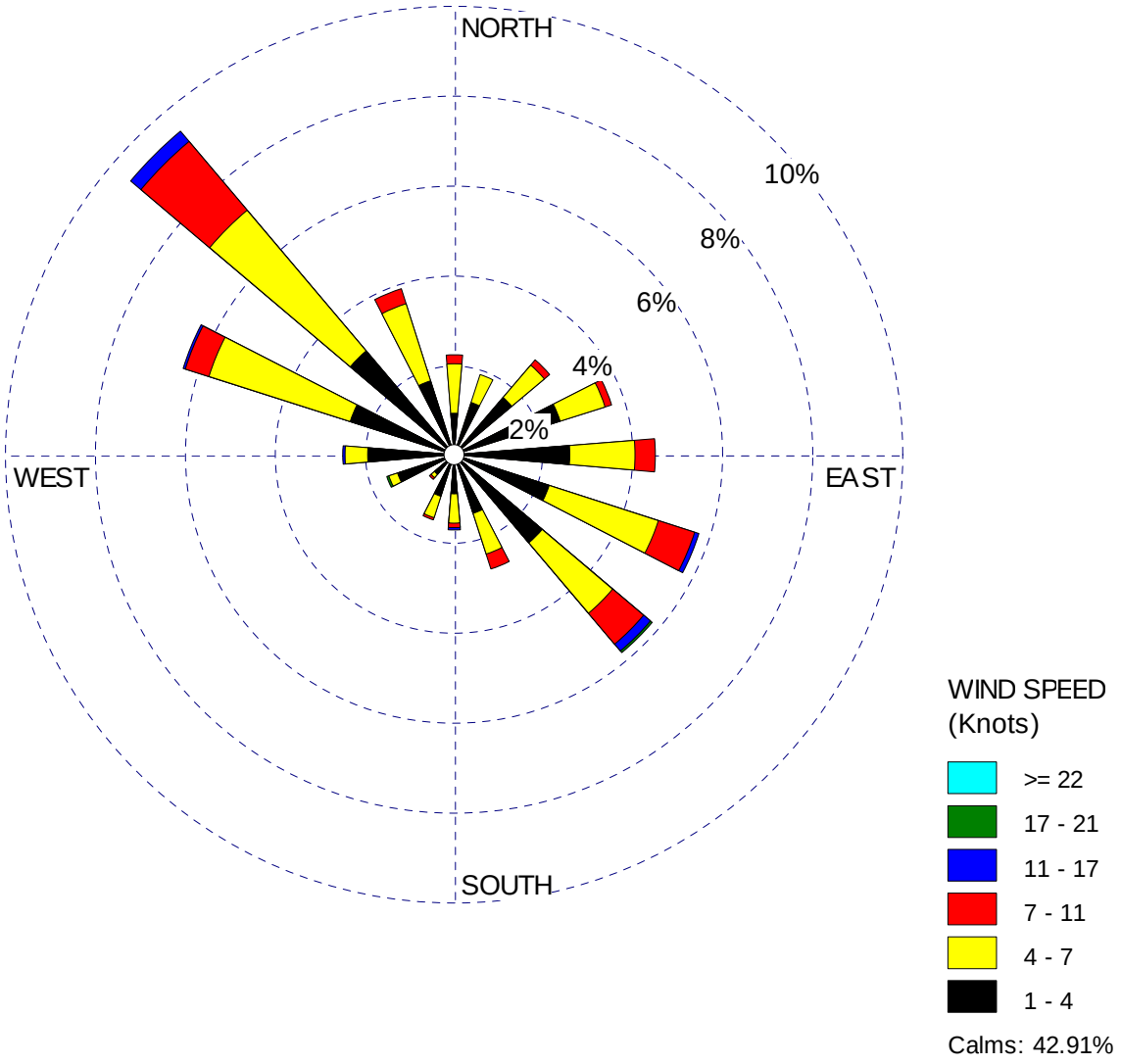

Figure 6.2-5p
Annual Wind Rose
Hanford, California
January 1, 2003 through December 31, 2003

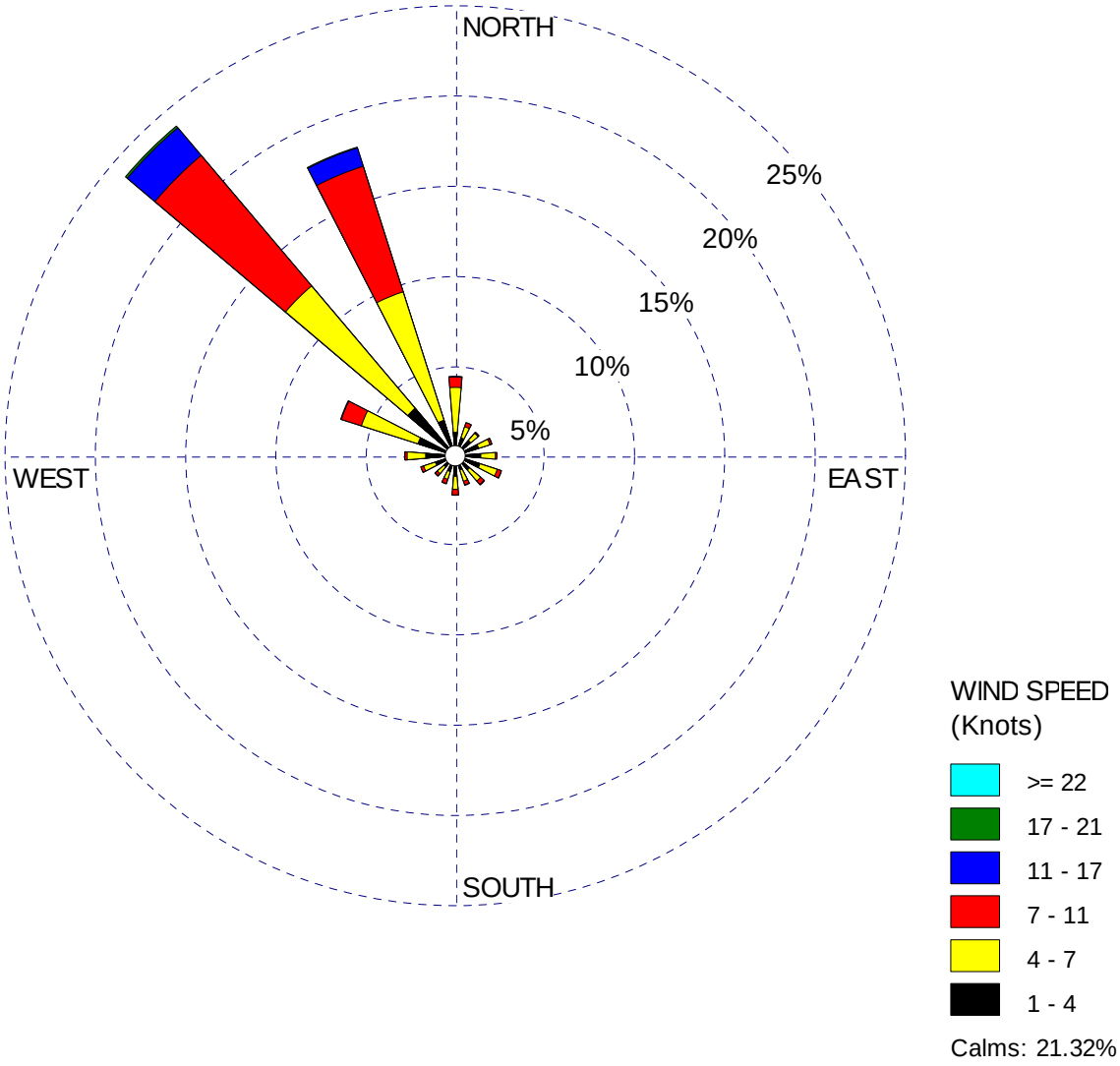

Figure 6.2-5q
First Quarter Wind Rose
Hanford, California
January 1, 2003 through March 31, 2003

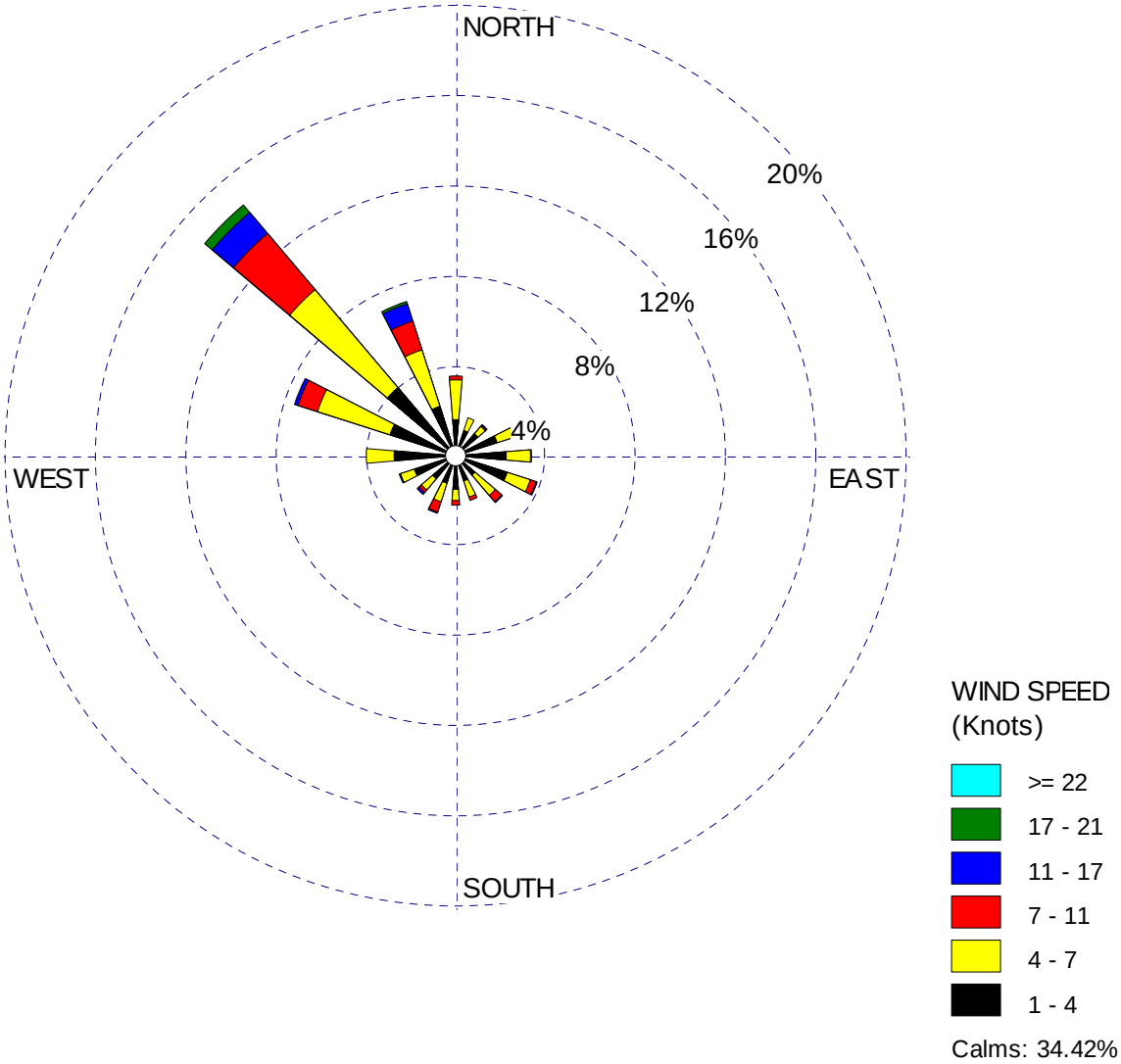

Figure 6.2-5r
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Hanford, California
April 1, 2003 through June 30, 2003

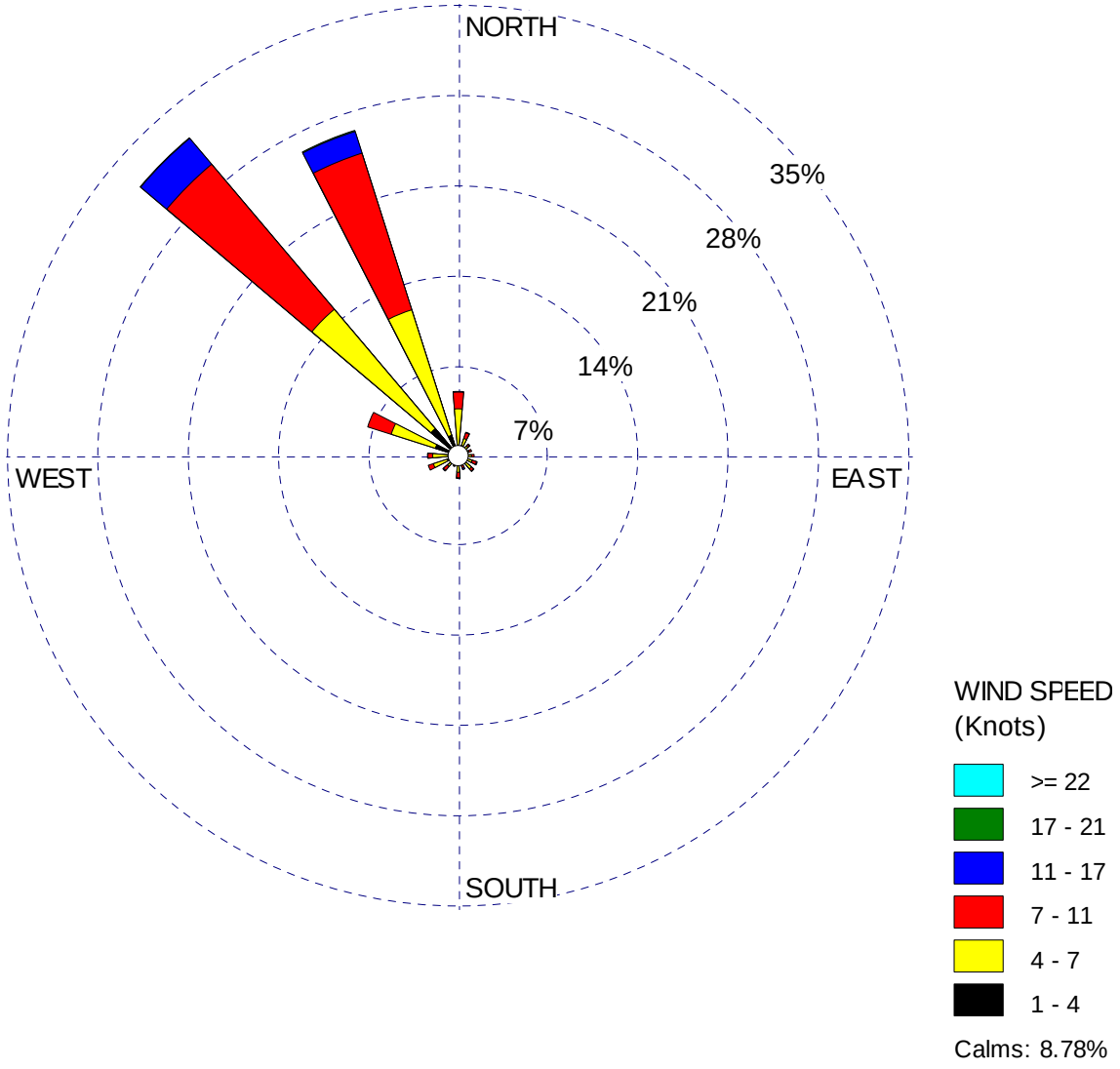

Figure 6.2-5s
Third Quarter Wind Rose
Hanford, California
July 1, 2003 through September 30, 2003

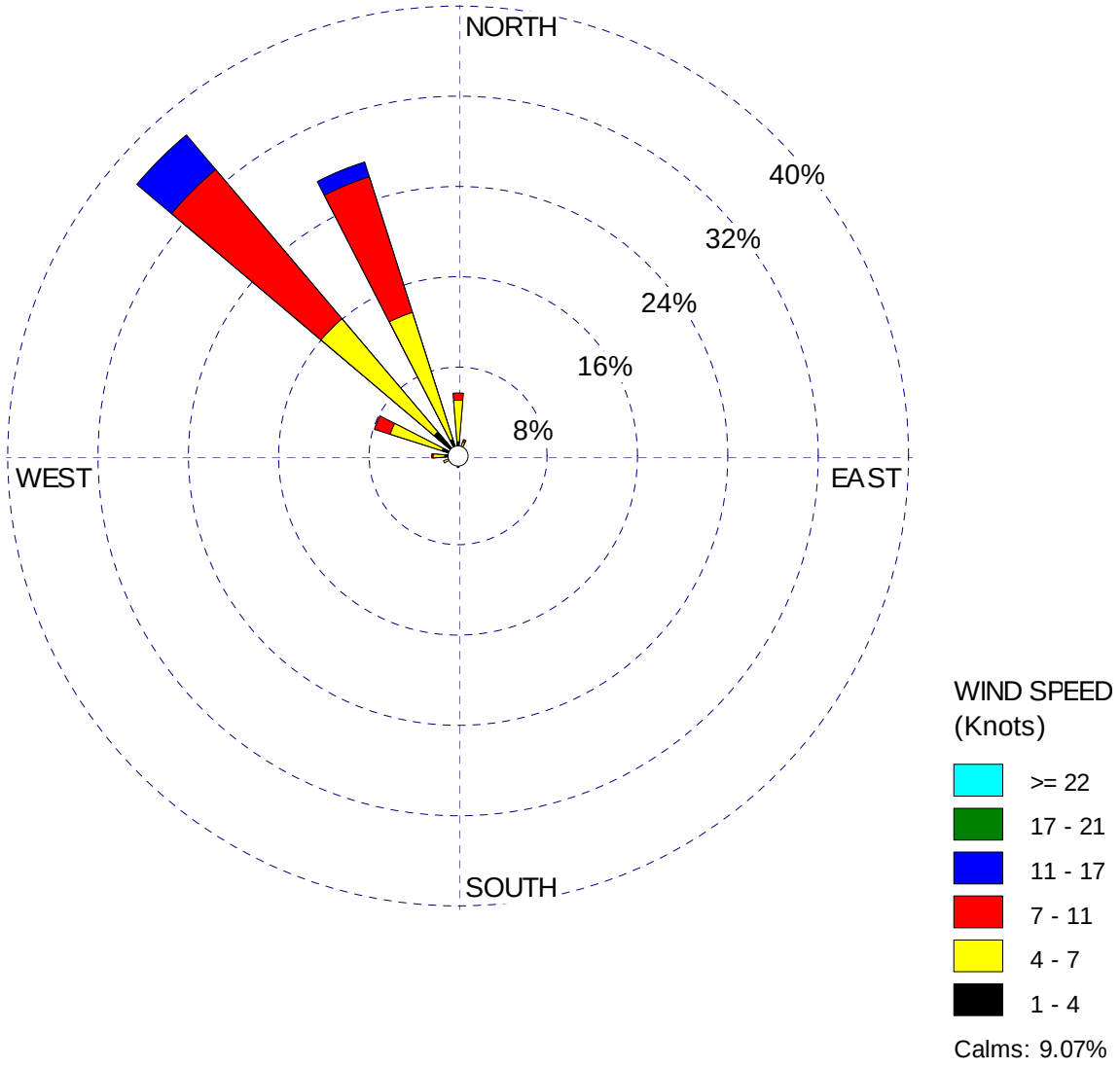

Figure 6.2-5t
Fourth Quarter Wind Rose
Hanford, California
October 1, 2003 through December 31, 2003

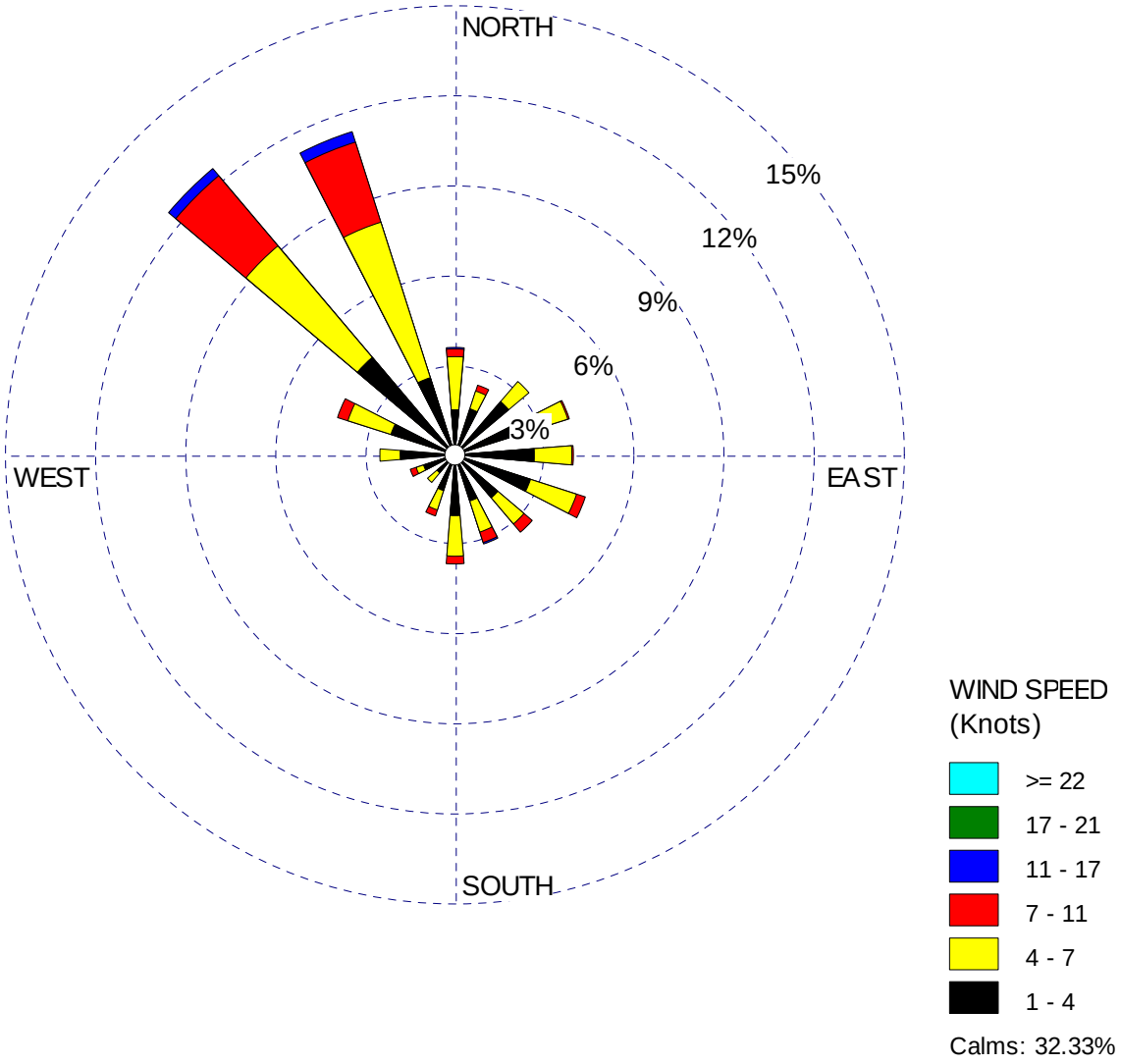

Figure 6.2-5u
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Hanford, California
January 1, 2004 through December 31, 2004

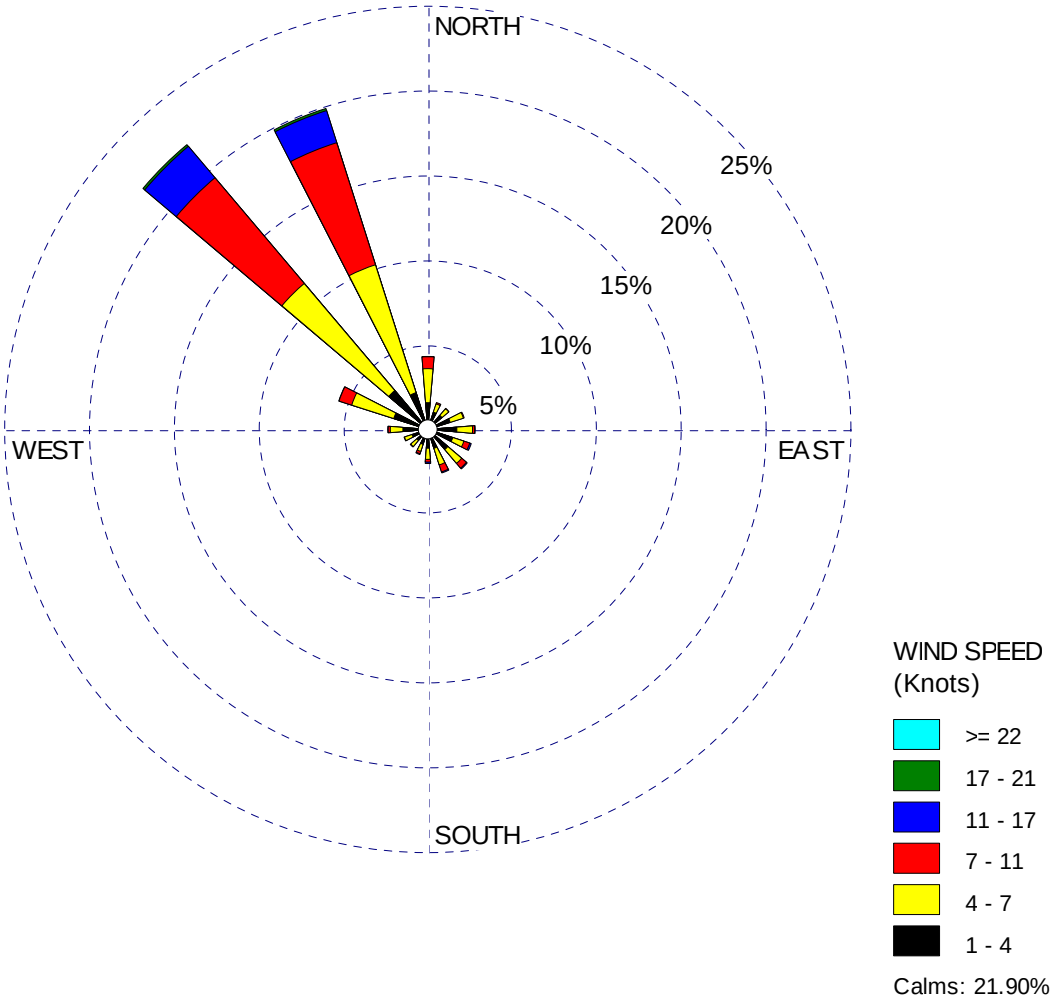

Figure 6.2-5v
First Quarter Wind Rose
Hanford, California
January 1, 2004 through March 31, 2004

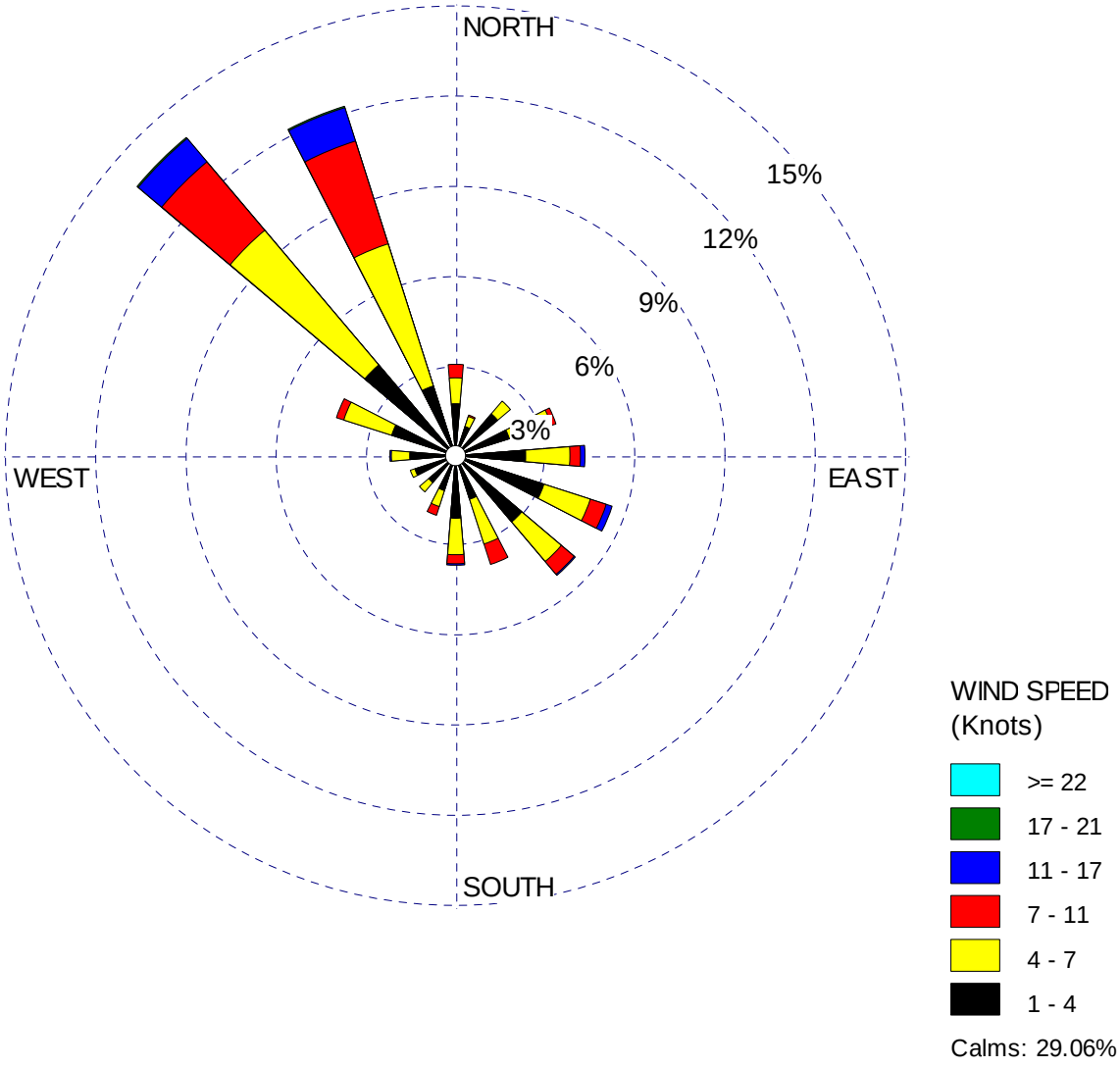

Figure 6.2-5w
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Hanford, California
April 1, 2004 through June 30, 2004

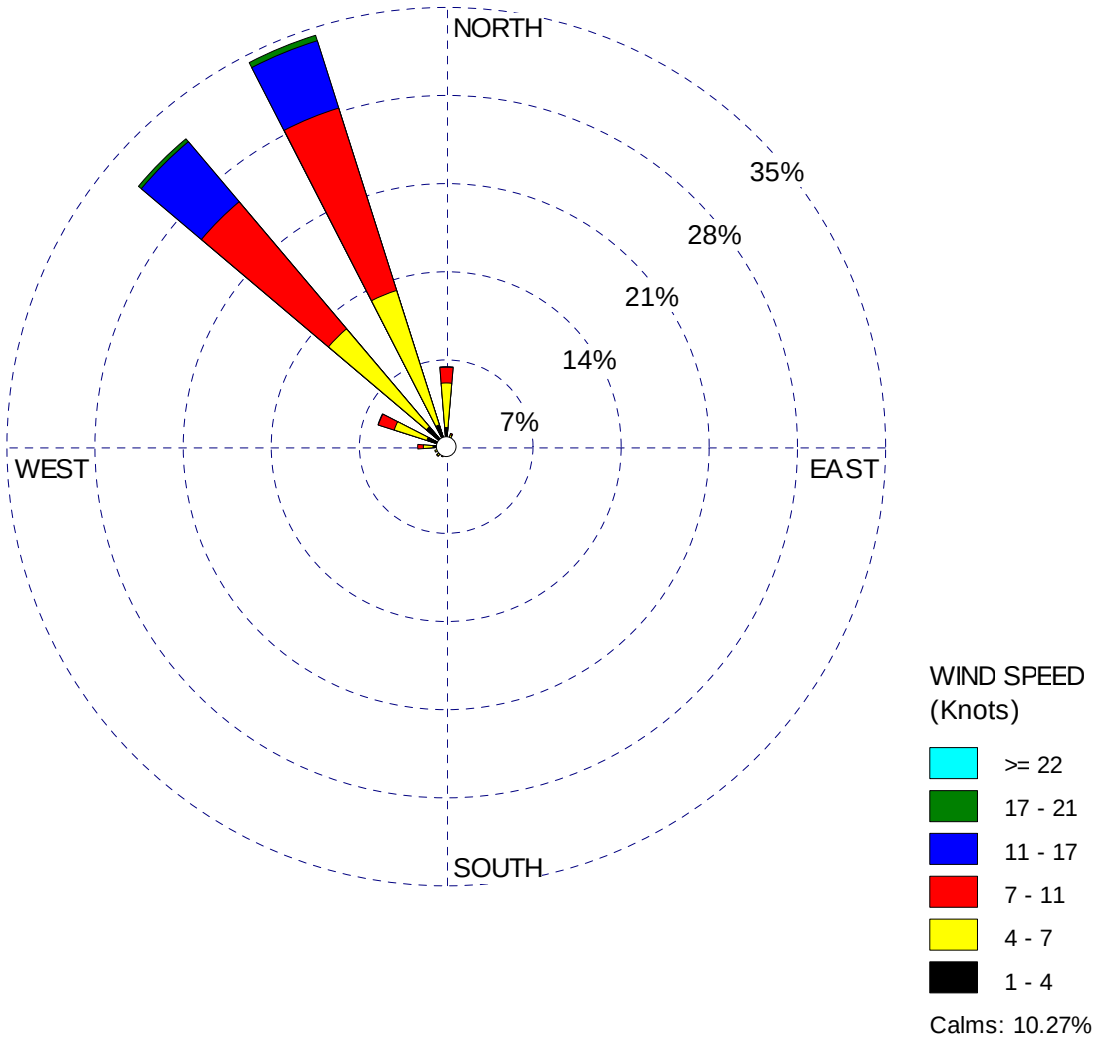

Figure 6.2-5x
Third Quarter Wind Rose
Hanford, California
July 1, 2003 through September 30, 2003

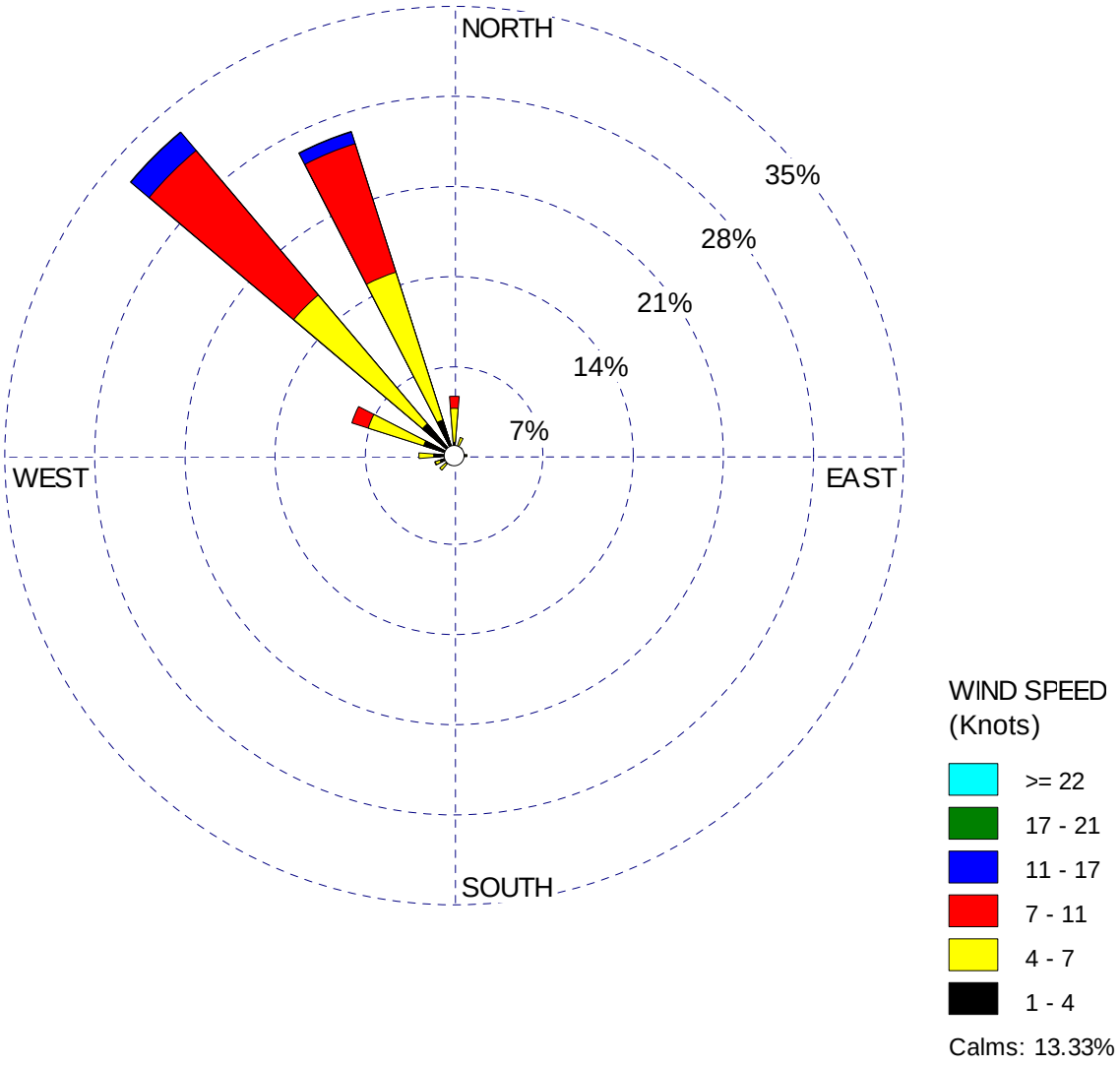

Figure 6.2-5y
Fourth Quarter Wind Rose
Hanford, California
October 1, 2004 through December 31, 2004

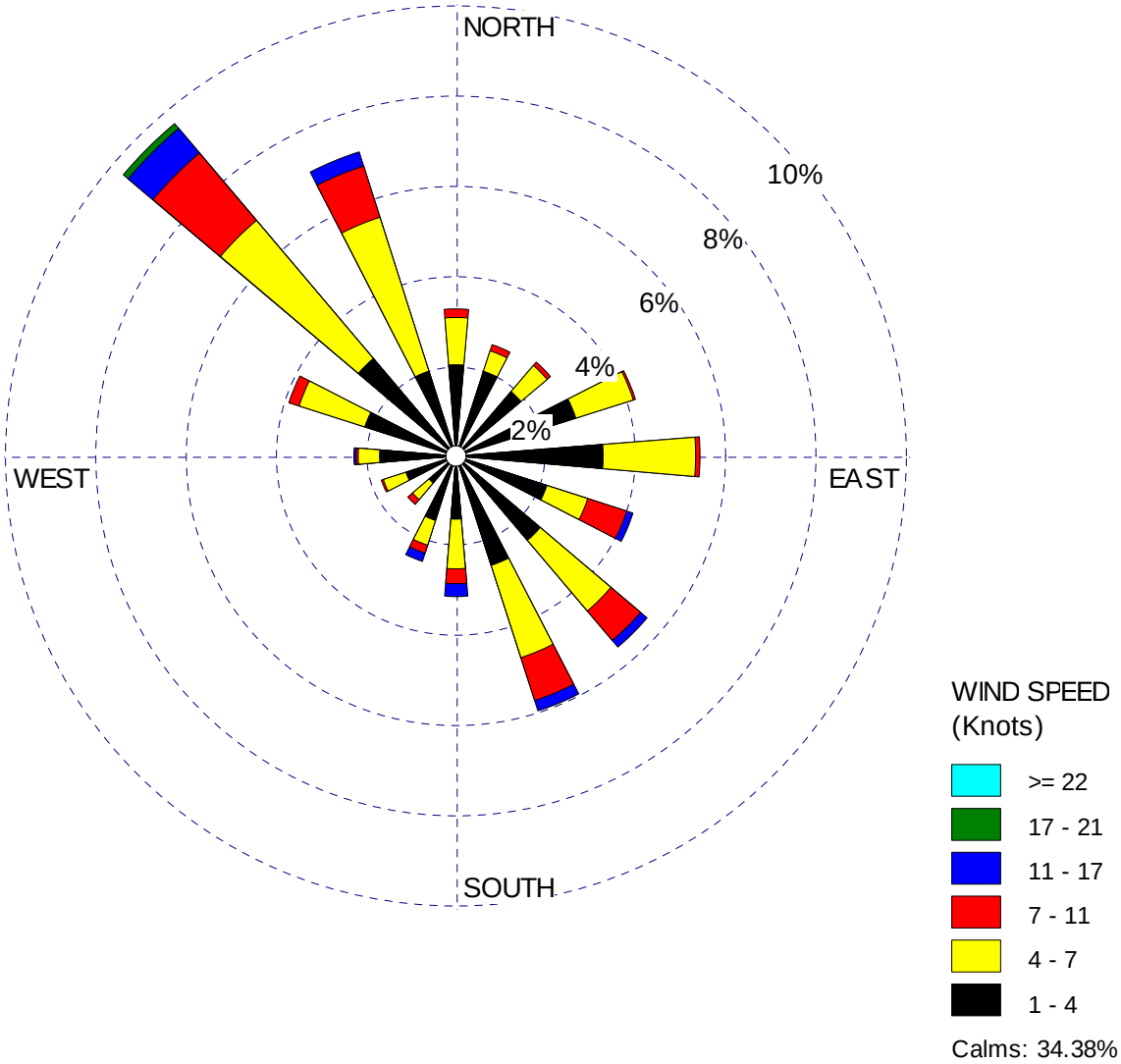

Figure 6.2-6
Maximum Hourly Ozone Levels
Hanford, 1997-2006

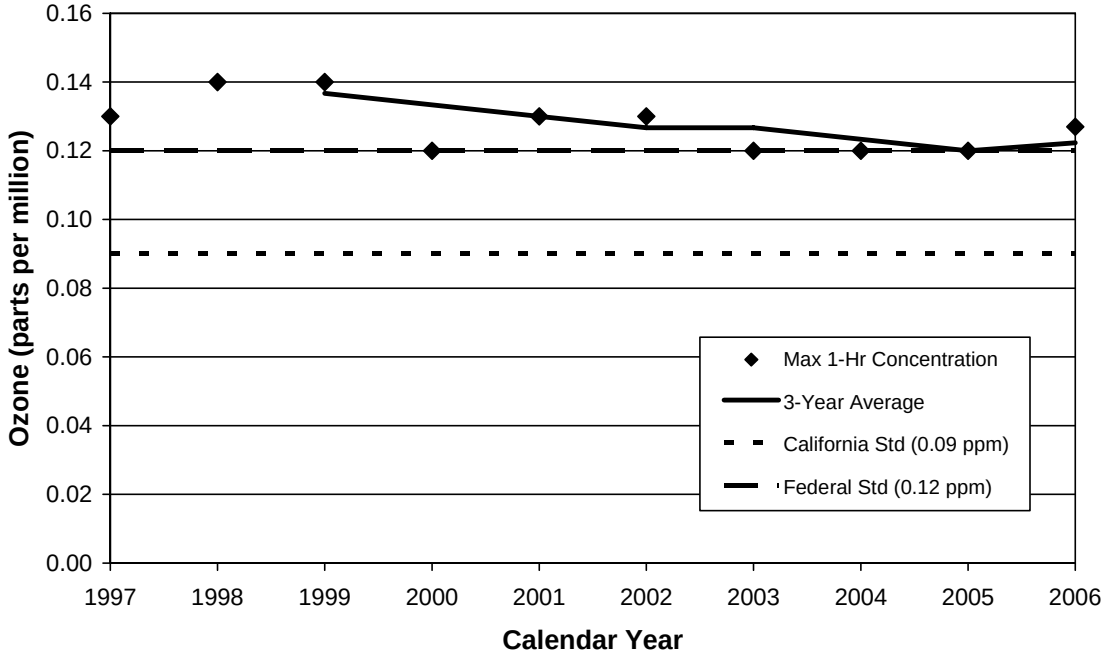

Figure 6.2-7
Violations of the California 1-Hour Ozone Standard (0.09 ppm)
Hanford, 1997-2006

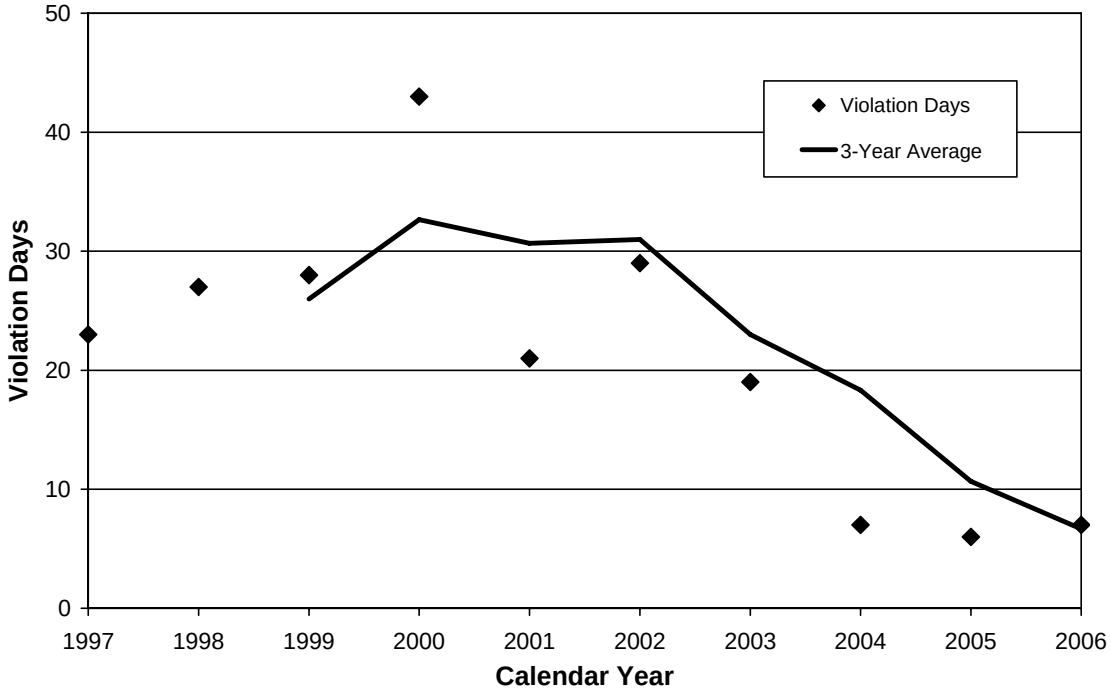

Figure 6.2-7A
3-Year Average 4th Highest 8-Hour Average Ozone Levels
Hanford, 1997-2006

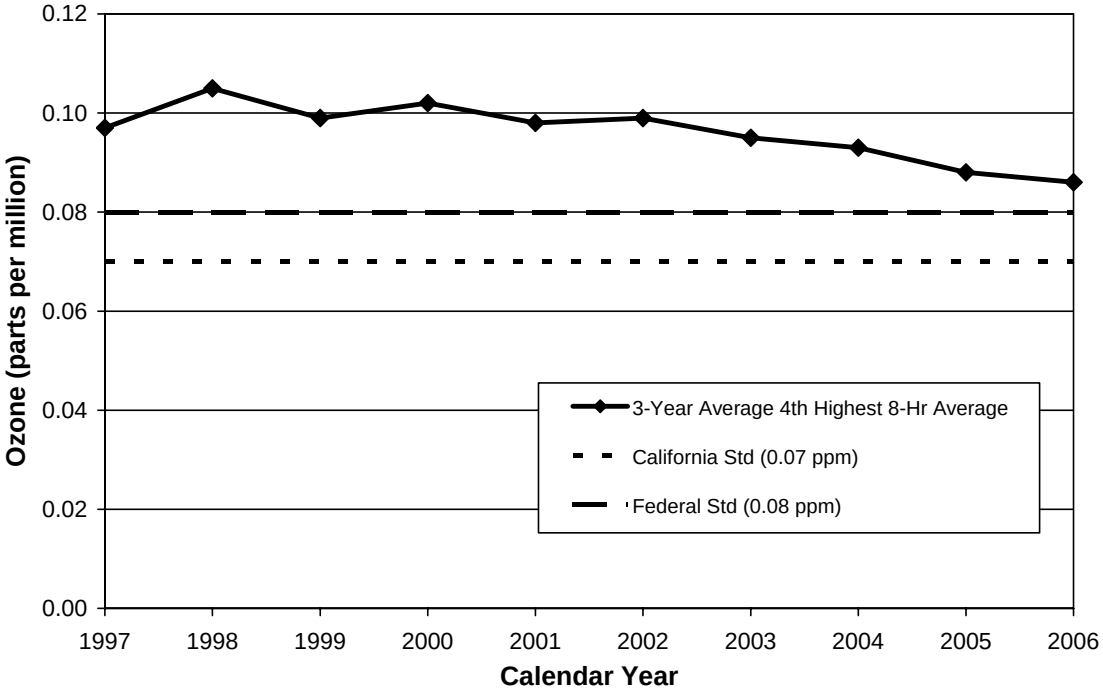

Figure 6.2-8
Maximum Hourly NO_2 Levels in the Project Area
1997-2006

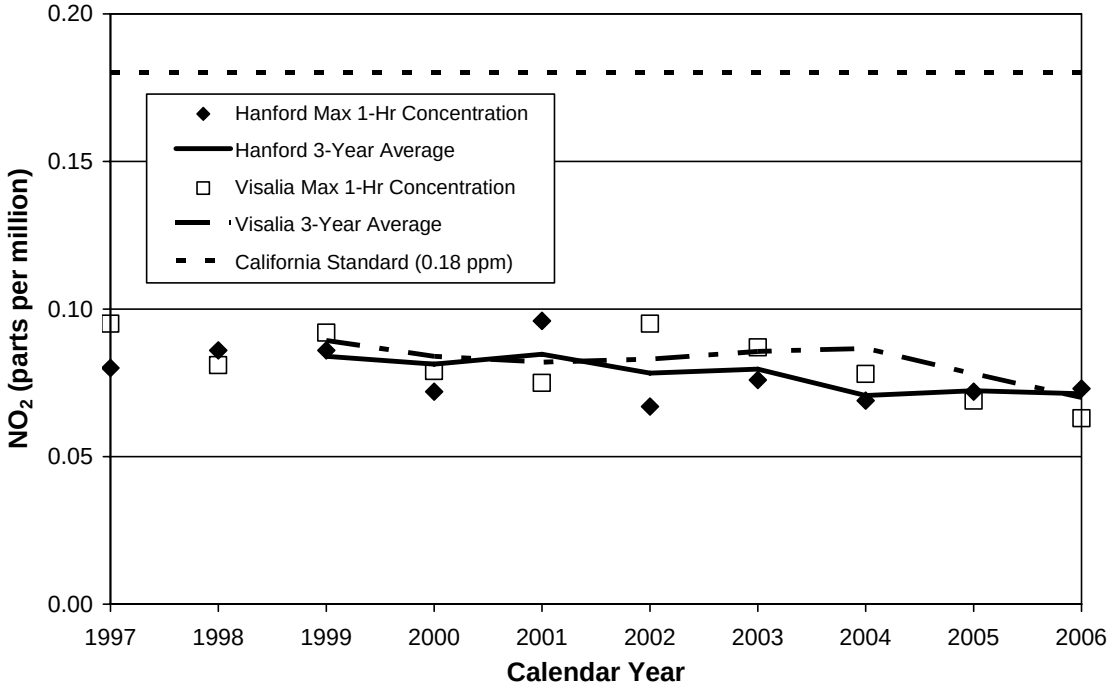

Figure 6.2-8A
Annual Average NO_2 Levels in the Project Area
1997-2006

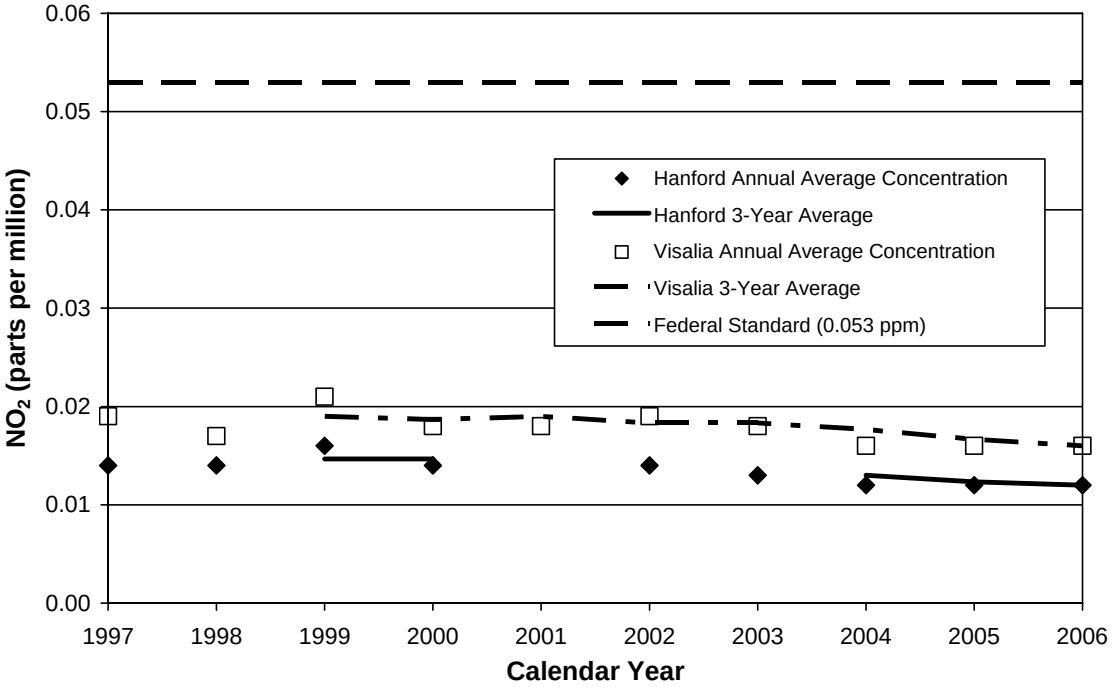

Figure 6.2-10
Maximum 1-Hour Average CO Levels
Visalia, 1997-2006

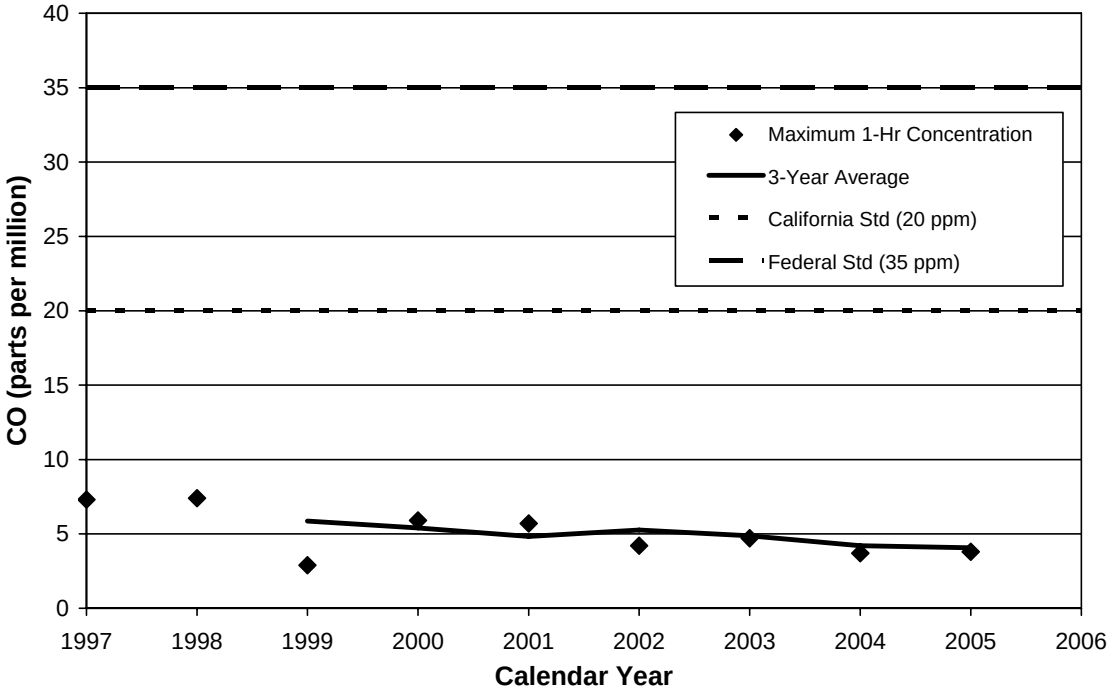

Figure 6.2-9
Maximum 8-Hour Average CO Levels
Visalia, 19970-2006

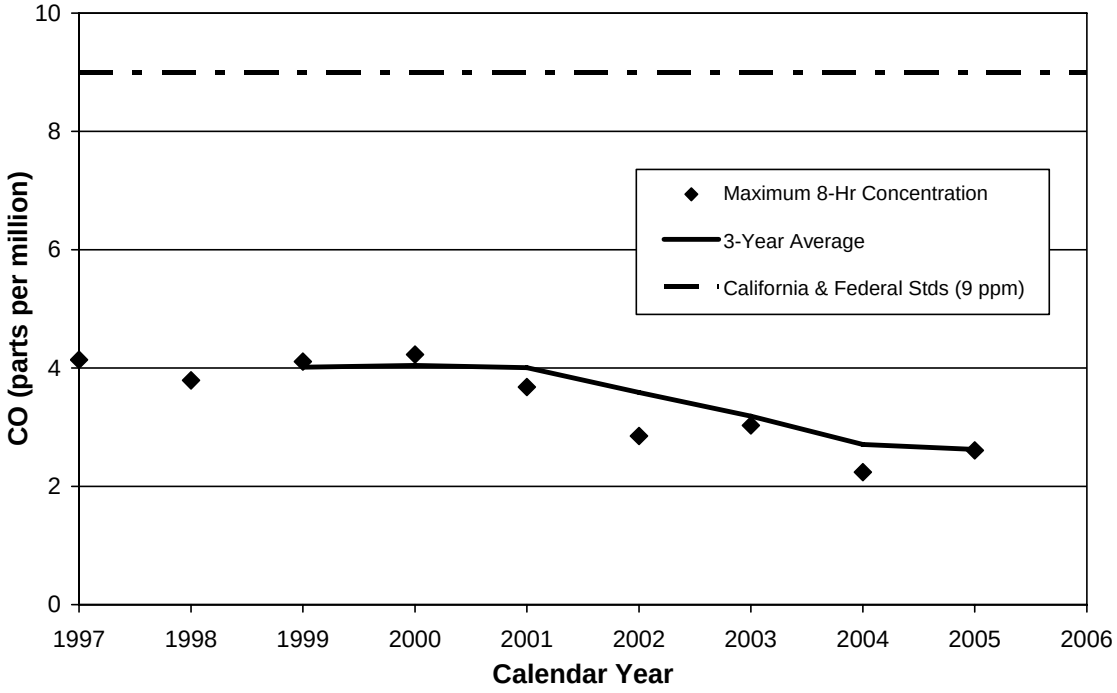

Figure 6.2-11
Maximum 1-Hour Average SO_2 Levels
Bakersfield & Sacramento, 1997-2006

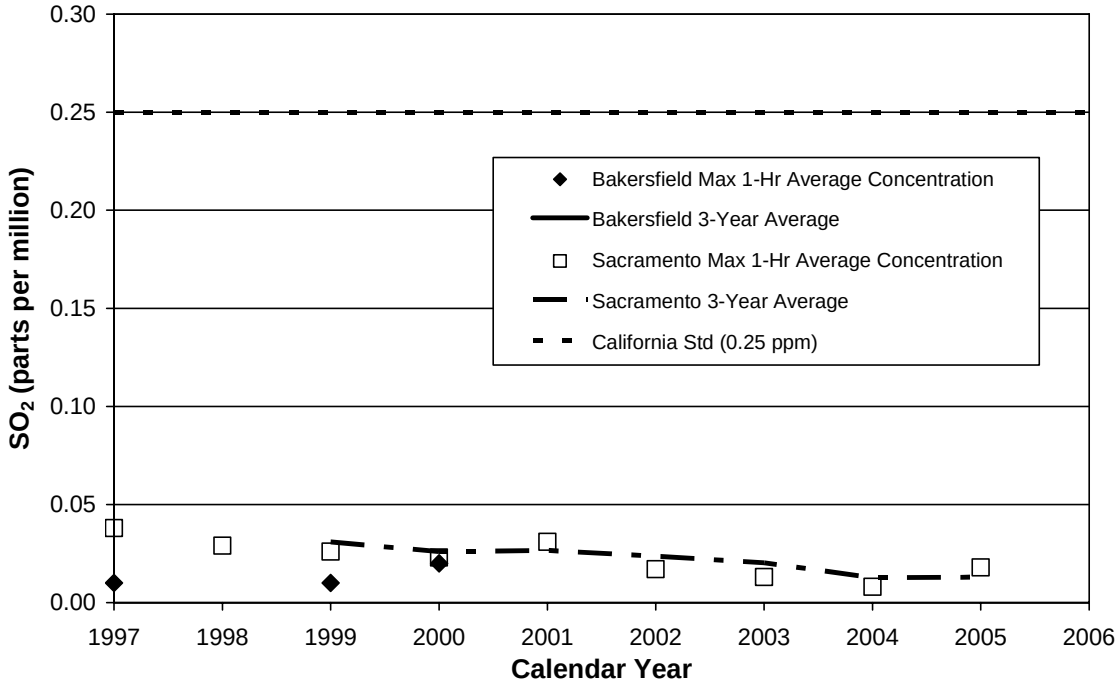

Figure 6.2-12
Maximum 24-Hour Average Sulfate Levels
Bakersfield, 1990-1997

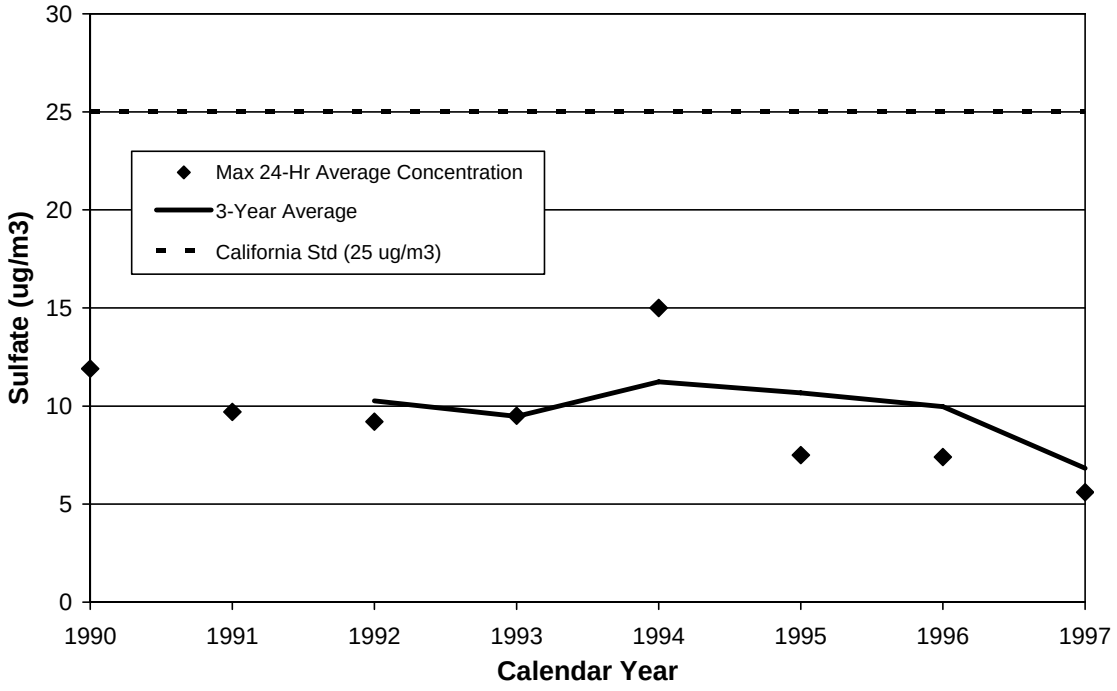

Figure 6.2-13
Maximum 24-Hour Average PM10 Levels
in Kings County, 1997-2006

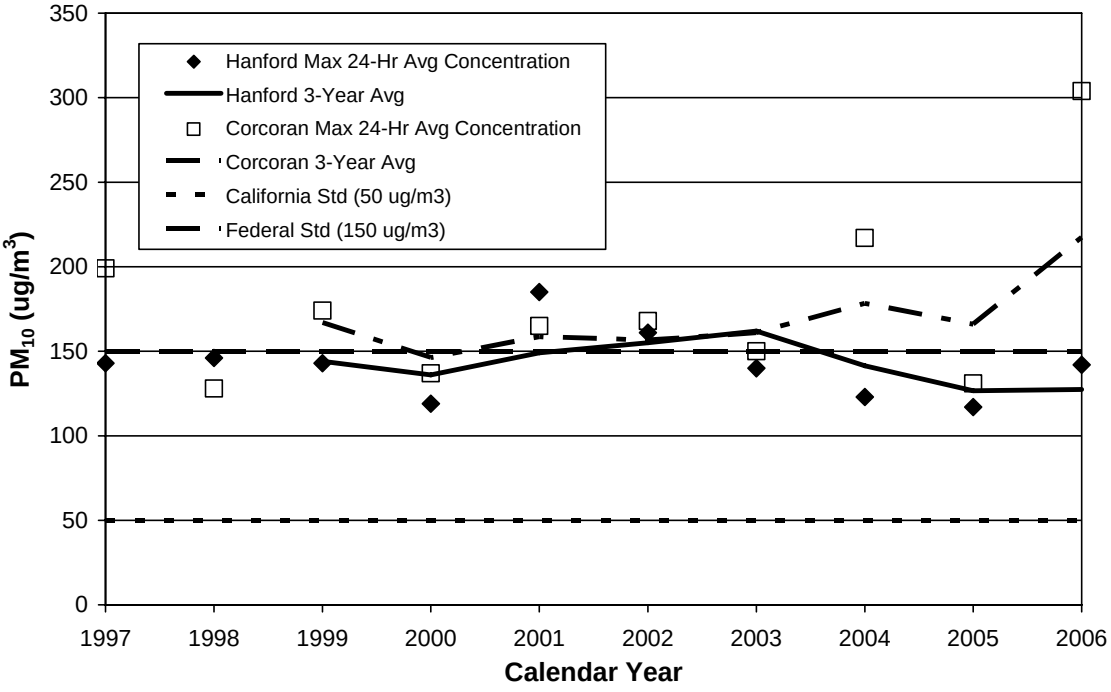

Figure 6.2-14
Expected Violations of the California 24-Hour PM10 Standard (50 ug/m3) in Kings County (1997-2006)

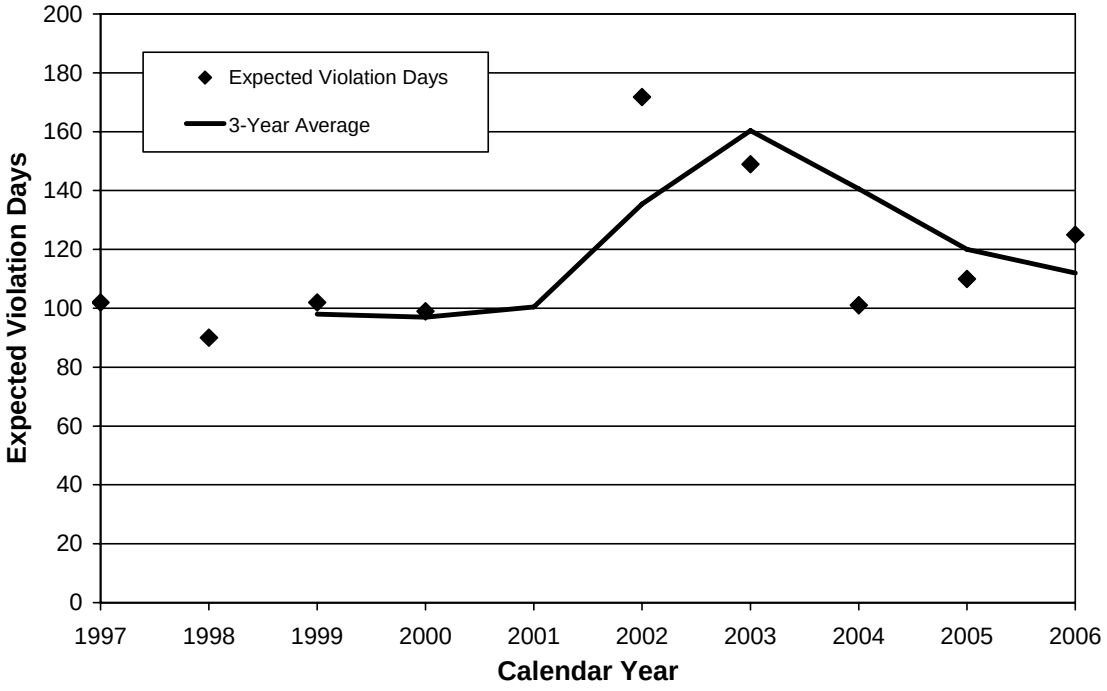

Figure 6.2-15
Maximum & 98th Percentile 24-Hour Average PM2.5 Levels
Corcoran, 1997-2006

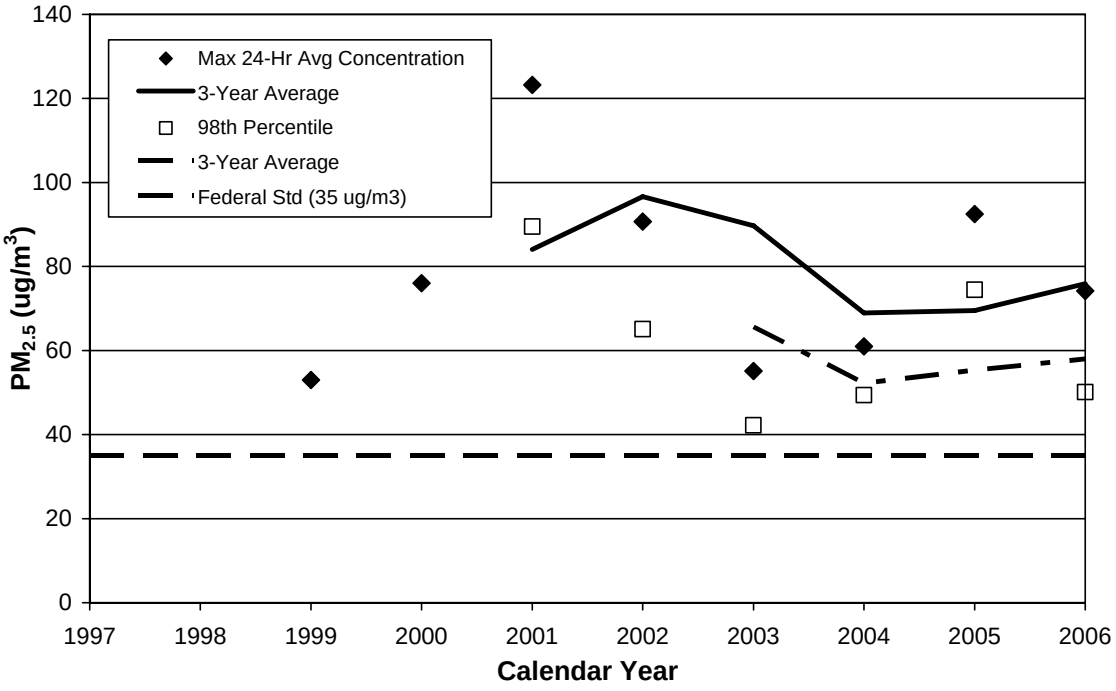

Figure 6.2-16
Quarterly Average Lead Levels
Central Valley, 1997-2006

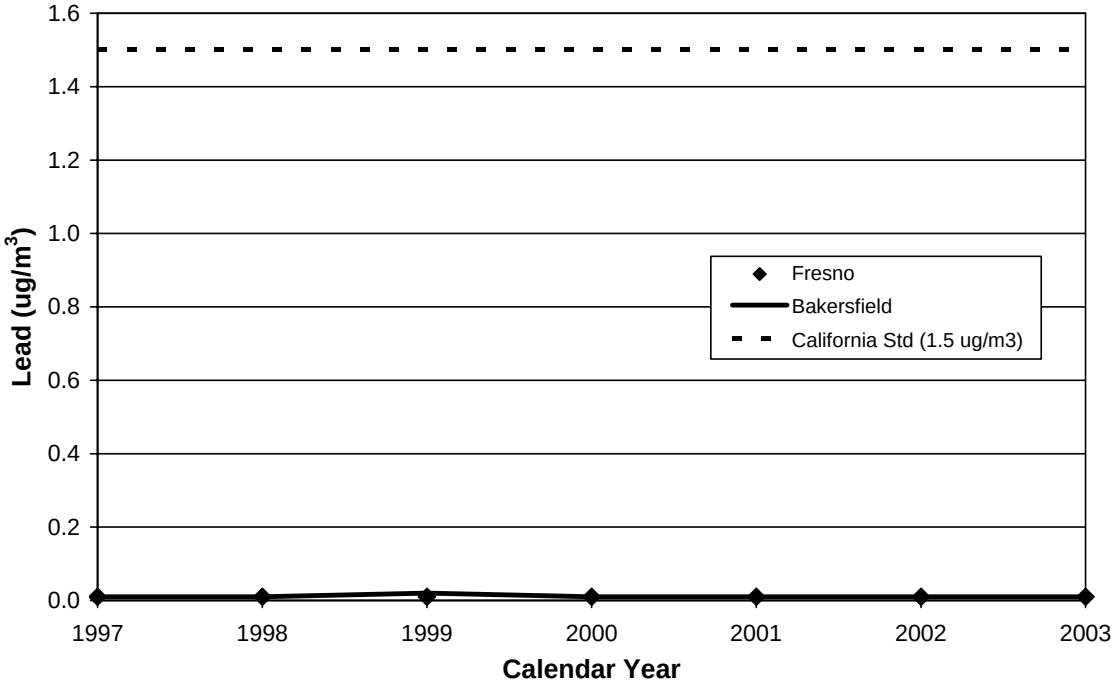
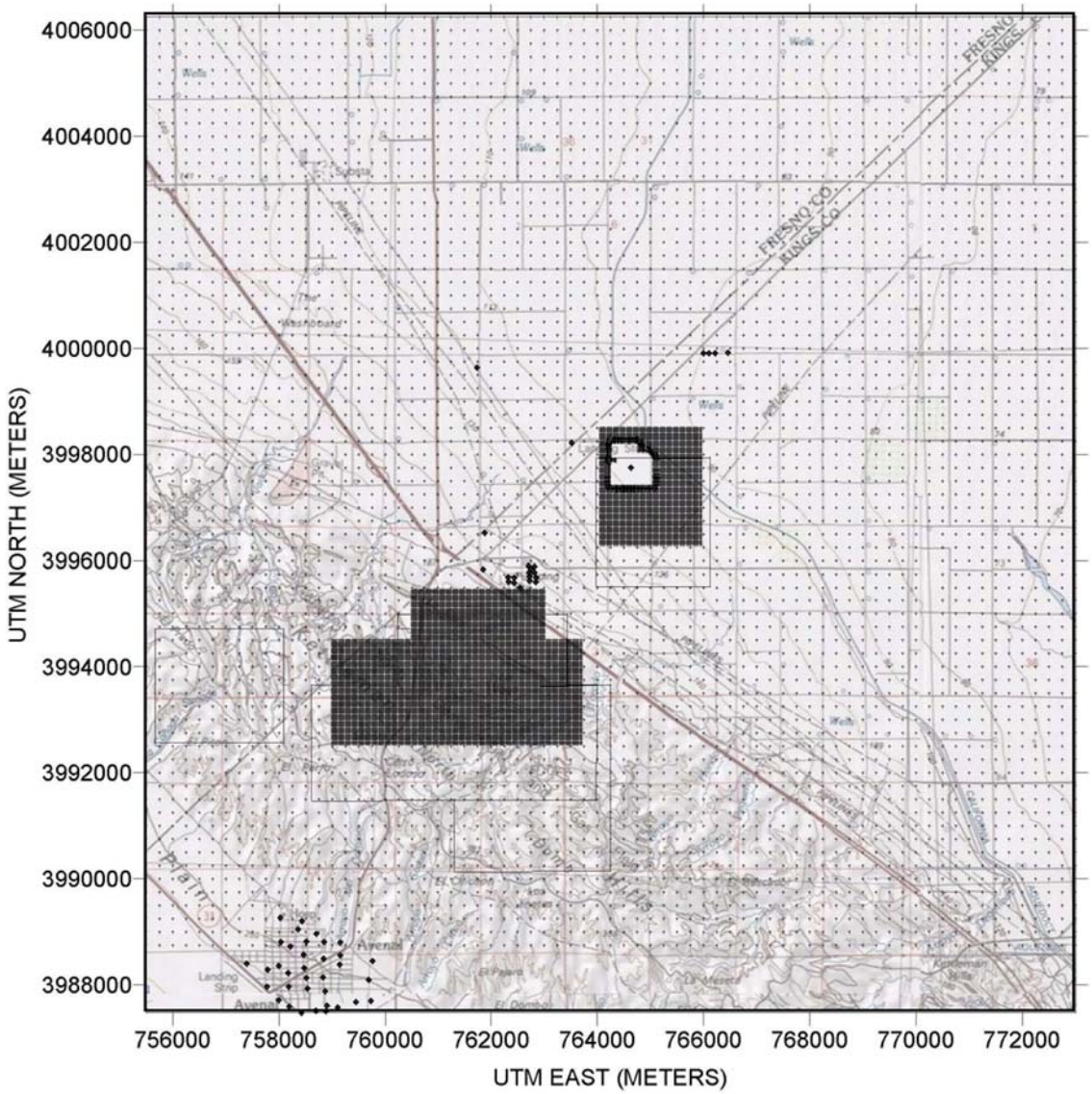
Figure 6.2-17
Discrete Receptors and Grids