Final Staff Assessment
Air Quality Addendum

CPV Sentinel Energy Project

Application For Certification (07-AFC-3)
Riverside County

CALIFORNIA ENERGY COMMISSION

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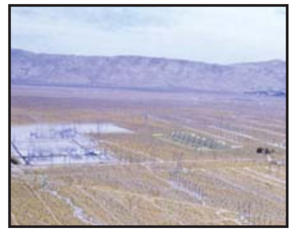

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CPV SENTINEL ENERGY UPGRADE PROJECT
(07-AFC-3)
FINAL STAFF ASSESSMENT AIR QUALITY ADDENDUM

EXECUTIVE SUMMARY

John Kessler

INTRODUCTION

This Final Staff Assessment Air Quality Addendum (FSA Addendum) contains the California Energy Commission staff's updated analysis of air quality for the applicant's (CPV Sentinel, LLC's) CPV Sentinel Energy Project (CPV Sentinel) Application for Certification (07-AFC-3). At the time the FSA was published on October 10, 2008, staff's assessment was incomplete in the area of air quality because the applicant had not yet secured the Emission Reduction Credits (ERCs) needed to offset the project's emissions. Since then, the applicant has secured the necessary ERCs and staff is able to update its analysis and draw conclusions as to the project's conformity with air quality laws, ordinances, regulations and standards (LORS) and whether environmental impacts are avoided or mitigated to less than significant levels. The FSA Addendum has been prepared in conformity with the Energy Commission's California Environmental Quality Act (CEQA) review process. The Energy Commission's CPV Sentinel Committee will hear the various parties' views on this FSA Addendum and the topic of Air Quality in an Evidentiary Hearing scheduled for July 19, 2010.

SUMMARY OF PROJECT RELATED IMPACTS

Staff has concluded that with the applicant's and staff's proposed mitigation measures and staff's proposed conditions of certification, the CPV Sentinel project would not cause any significant adverse direct, indirect or cumulative impacts and would comply with all applicable laws, ordinances, regulations, and standards (LORS). For a more detailed review of potential impacts in technical areas other than air quality, please see staff's technical analyses in the FSA as available on the Energy Commission's Internet web site at: http://www.energy.ca.gov/sitingcases/sentinel/index.html. The status of each technical area as concluded by staff in the FSA and updated in this FSA Addendum is summarized in the table below.

The discussion following the table provides a summary of staff's conclusions with respect to air quality as presented in this FSA Addendum.

Technical Area	Complies with LORS	Impacts Mitigated
Air Quality	**Yes** ~~Undetermined~~	**Yes** ~~Undetermined~~
Biological Resources	Yes	Yes
Cultural Resources	Yes	Yes
Efficiency	Yes	Yes
Facility Design	Yes	Yes
Geology & Paleontology	Yes	Yes
Hazardous Materials	Yes	Yes
Land Use	Yes	Yes
Noise	Yes	Yes
Public Health	Yes	Yes
Reliability	Yes	Yes
Socioeconomic Resources	Yes	Yes
Soil & Water Resources	Yes	Yes
Traffic & Transportation	Yes	Yes
Transmission Line Safety/Nuisance	Yes	Yes
Transmission System Engineering	Yes	Yes
Visual Resources	Yes	Yes
Waste Management	Yes	Yes
Worker Safety and Fire Protection	Yes	Yes

AIR QUALITY

Staff finds that with the adoption of the recommended conditions of certification, the proposed CPV Sentinel project would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related impacts. Staff also finds that:

- The project would comply with applicable South Coast Air Quality Management District (SCAQMD or District) Rules and Regulations, including New Source Review (NSR) requirements.
- The project would not cause new violations of any NO_2, SO_2, or CO ambient air quality standards, and therefore, the project's direct NOx, SOx and CO emission impacts are not significant. The analyses did not need to include the new federal short-term NO_2 ambient air quality standard because it was not in effect at the time the project application was filed with the District and the Energy Commission.
- Without mitigation, the project's NOx and VOC emissions would potentially contribute to existing violations of the state's 1-hour and the federal 8-hour ozone air quality standards. Staff has determined that emission offset credits from the South Coast Air Basin would mitigate the project's contribution to ozone impacts to a level that is not cumulatively considerable (Condition of Certification **AQ-SC8**).
- Without mitigation, the project's PM10 emissions and PM10 precursor emissions of SOx would contribute to the existing violations of the state 24-hour PM10 air quality

standard. However, staff has determined that emission reduction credits would mitigate the project's contribution to PM10 and PM10 precursor emissions impacts to a level that is not cumulatively considerable.

- Without mitigation, the project's PM2.5 emissions and PM2.5 precursor emissions of SOx would contribute to existing violations of the federal 24-hour PM2.5 or the state annual PM2.5 air quality standard. Therefore, potential impacts are considered significant. However, staff has determined that emission reduction credits would mitigate the project's contribution to PM2.5 impacts to a level that is not cumulatively considerable.
- The project meets the requirements of Assembly Bill 1318 to qualify for obtaining emission offsets from the SCAQMD's internal offset account.
- Staff has analyzed the potential incremental greenhouse gas (GHG) emission impacts from the proposed project and concludes that they are not cumulatively considerable and thus do not represent a significant impact under the California Environmental Quality Act (CEQA). Refer to the Greenhouse Gas Appendix for details.

ENVIRONMENTAL JUSTICE

Absent any non-conformity with LORS or significant unmitigated environmental impacts, staff concludes there will not be a disproportionately high and adverse human health or environmental effect on a minority and/or low-income population, and thus, no disproportional impact to an environmental justice population.

RECOMMENDATIONS AND SCHEDULE

For all technical areas, staff concludes that with the adoption of the recommended conditions of certification, the project will not cause a significant adverse environmental impact and would conform to all applicable LORS. Staff recommends that the CPV Sentinel project be certified.

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

Testimony of Steven R. Radis

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached conditions of certification the proposed CPV Sentinel Energy Project (CPV Sentinel) would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related impacts. Staff also finds that:

- The project would comply with applicable South Coast Air Quality Management District (SCAQMD or District) Rules and Regulations, including New Source Review (NSR) requirements (SCAQMD 2010a).
- The project would not cause new violations of any NO_2, SO_2, or CO ambient air quality standards, and therefore, the project's direct NOx, SOx and CO emission impacts are not significant. The analyses did not need to include the new federal short-term NO_2 ambient air quality standard because it was not in effect at the time the project application was filed with the District and the Energy Commission.
- Without proper mitigation, the project's NOx and VOC emissions would potentially contribute to existing violations of the state's 1-hour and the federal 8-hour ozone air quality standards. Staff has determined that emission offset credits from the South Coast Air Basin would mitigate the project's contribution to ozone impacts to a level that is not cumulatively considerable (**AQ-SC8**).
- Without mitigation, the project's PM10 emissions and PM10 precursor emissions of SOx would contribute to the existing violations of the state 24-hour PM10 air quality standard. However, staff has determined that emission reductions credits would mitigate the project's contribution to PM10 and PM10 precursor emissions impacts to a level that is not cumulatively considerable.
- Without mitigation, the project's PM2.5 emissions and PM2.5 precursor emissions of SOx would contribute to existing violations of the federal 24-hour PM2.5 or the state annual PM2.5 air quality standard. Therefore, potential impacts are considered significant. However, staff has determined that emission reduction credits would mitigate the project's contribution to PM2.5 impacts to a level that is not cumulatively considerable.
- The project meets the requirements of Assembly Bill 1318 to qualify for obtaining emission offsets from the SCAQMD's internal offset account.
- Staff has analyzed the potential incremental greenhouse gas (GHG) emission impacts from the proposed project and concludes that they are not cumulatively considerable and thus do not represent a significant impact under the California Environmental Quality Act (CEQA). Refer to the Greenhouse Gas Appendix for details.

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to CPV Sentinel, LLC's (applicant's) proposed construction and operation of the CPV Sentinel Energy Project (CPV Sentinel). Criteria air pollutants are defined as those air contaminants for which the state and/or federal government has established an ambient air quality standard to protect public health. The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide ($SO_{2)}$, carbon monoxide (CO), ozone (O_3), and particulate matter (PM10 and PM2.5). In addition, volatile organic compounds (VOC) emissions are analyzed because they are precursors to both ozone (O_3) and particulate matter. Because NO_2 and SO_2 readily react in the atmosphere to form other oxides of nitrogen and sulfur respectively, the terms nitrogen oxides (NOx) and sulfur oxides (SOx) are also used when discussing these two pollutants.

In carrying out this analysis, Energy Commission staff evaluated the following three major points:

Whether the CPV Sentinel project is likely to conform with applicable federal, state and South Coast Air Quality Management District (SCAQMD or District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));

Whether the CPV Sentinel project is likely to cause significant new violations of ambient air quality standards or contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1742 (b)); and

Whether the mitigation proposed for the CPV Sentinel project is adequate to lessen any potentially significant impacts to a less than significant level (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The following federal, state, and local laws and policies pertain to the control of criteria pollutant emissions and mitigation of air quality impacts. Staff's analysis examines the project's compliance with these requirements, shown in **AIR QUALITY Table 1**.

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Permitting and enforcement delegated to SCAQMD. Prevention of Significant Deterioration

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
	(PSD) requires major sources to obtain permits for attainment pollutants. A major source for a simple-cycle combustion turbine is defined as any one pollutant exceeding 250 tons per year. Since the emissions from the CPV Sentinel project are not expected to exceed 250 tons per year, PSD does not apply.
40 CFR 60 Subpart KKKK	New Source Performance Standard for gas turbines: 15 parts per million (ppm) NOx at 15% O_2 and fuel sulfur limit of 0.060 lb SOx per million Btu heat input. BACT will be more restrictive. Enforcement delegated to SCAQMD.
40 CFR Part 70	Title V: Federal permit assuring compliance with all applicable Clean Air Act requirements. Title V permit application required within one year of start of operation. Permitting and enforcement delegated to SCAQMD.
40 CFR Part 72	Acid Rain Program. Requires permit and obtaining sulfur oxides credits. Permitting and enforcement delegated to SCAQMD.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with approved Clean Air Plan.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
HSC Sections 21080, 39619.8, 40440.14 (AB1318)	Requires the executive officer of the South Coast Air Quality Management District, upon making a specified finding, to transfer emission reduction credits for certain pollutants from the South Coast District's internal emission credit accounts to eligible electrical generating facilities.
Local – South Coast Air Quality Management District (SCAQMD)	
Regulation II: Permits	This regulation sets forth the regulatory framework of the application for issuance of construction and operation permits for new, altered and existing equipment.

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Regulation IV: Prohibitions	This regulation sets forth the restrictions for visible emissions, odor nuisance, fugitive dust, various air emissions, fuel contaminants, start-up/shutdown exemptions and breakdown events.
Regulation VII: Emergencies	Establishes the procedures for reporting emergencies and emergency variances.
Regulation IX: Standards of Performance for New Stationary Sources	Regulation IX incorporates provisions of 40 CFR Part 60, Chapter I, and is applicable to all new, modified, or reconstructed sources of air pollution. Sections of this regulation apply to electric utility steam generators (Subpart Da) and stationary combustion turbines (Subpart KKKK). These subparts establish limits of PM10, SO_2, and NO_2 emissions from the facility as well as monitoring and test method requirements.
Regulation XI: Source Specific Standards	Specifies the performance standards for stationary engines larger than 50 brake horse power (bhp).
Regulation XIII: New Source Review	Establishes the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. However, this regulation does not apply to NOx or SOx emissions from certain sources, which are addressed by Regulation XX (RECLAIM).
Regulation XVII: Prevention of Significant Deterioration	This regulation sets forth the pre-construction requirement for stationary sources to ensure that the air quality in clean air areas does not significantly deteriorate while maintaining a margin for future industrial growth.
Regulation XX: Regional Clean Air Incentives Market (RECLAIM)	RECLAIM is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications,

AIR QUALITY Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
	reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reductions.
Regulation XXX: Title V Permits	The Title V federal program is the air pollution control permit system required by the federal Clean Air Act as amended in 1990. Regulation XXX defines the permit application and issuance as well as compliance requirements associated with the program. Any new or modified major source which qualifies as a Title V facility must obtain a Title V permit prior to construction, operation or modification of that source. Regulation XXX also integrates the Title V permit with the RECLAIM program such that a project cannot proceed without the other.
Regulation XXXI Acid Rain Permits	Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and carbon dioxide (CO_2) emissions from the facility.

SETTING

CLIMATE AND METEOROLOGY

The semi permanent high-pressure system centered off the west coast of the United States has a dominating influence on California's general climate. In the summer, this system results in low inversion layers with clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and funneling these toward Northern California.

The large-scale wind flow patterns in the South Coast air basin are a diurnal cycle driven by the differences in temperature between the land and the ocean in addition to the channeling effect of the mountainous terrain surrounding the basin. The Tehachapi and Temblor mountains physically separate the air shed in the South Coast and San Joaquin Valley air basins. The San Bernardino, San Gabriel, and Santa Rosa mountain ranges generally make up the eastern boundary of the South Coast air basin. The Santa Monica and Santa Ana coastal mountain ranges make up the northern and southern boundaries respectively.

The proposed project would be located in Riverside County, eight miles northwest of the City of Palms Springs. The area surrounding the project site is primarily industrial use with major development of wind energy and related transmission infrastructure. This area is at the east end of the San Gorgonio Pass in the Salton Sea Air Basin. The differences in season in the Salton Sea Basin are marked by air temperature and not rainfall, which is sparse year-round. The winter temperatures average approximately 70 degrees F, while the summer temperatures average 109 degrees F. The diurnal temperature differences (the temperature difference between night and day) ranges from 30 to 35 degrees F, which is substantial. The annual precipitation totals approximately five inches, primarily in the winter months.

The wind patterns near the project site are based on meteorological data from 1988 through 1991 and are dominated by strong winds (greater than 21 knots) from the west and west north-west, with a nighttime drainage pattern yielding occasional mild air flow from the southeast. Calm conditions were not detected.

The mixing heights, a parameter that defines the height through which pollutants released to the atmosphere are mixed, was recorded at the Desert Rock Station in Nevada (1988-1991) and will be used for the modeling analysis in place of the Edwards Air Base monitoring, which was recorded only 50 percent of the time. Mixing heights at Desert Rock were an average of 1,013 feet (approximately 308 meters).

AMBIENT AIR QUALITY STANDARDS

The United States Environmental Protection Agency (U.S. EPA) and the California Air Resource Board (CARB) have both established allowable maximum ambient concentrations of criteria air pollutants based on public health impacts, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically lower (more stringent) than the federal AAQS, established by the U.S. EPA. The state and federal air quality standards are listed in **AIR QUALITY Table 2**. As indicated, the averaging times for the various air quality standards (the duration over which all measurements taken are averaged) range from one hour to one year (annual). The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per unit volume of air, in milligrams (10^{-3} g, 0.001 g, or mg) or micrograms (10^{-6} g, 0.000001 g, or μg) of pollutant in a cubic meter (m^3) of air, averaged over the applicable time period.

In general, an area is designated as attainment for a specific pollutant if the concentrations of that air contaminant do not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data is available to support designation as either attainment or non-attainment, the area can be designated as unclassified. Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be designated as attainment for one air contaminant and non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of an air district is usually evaluated to determine the SCAQMD attainment status.

The ambient air quality standards shown in **AIR QUALITY Table 2** define the maximum amount of a pollutant that can be present in outdoor air without harm to the public's health. These standards are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants, and include a margin of safety.

EXISTING AMBIENT AIR QUALITY

The project is located in the unincorporated area of Riverside County, approximately 8 miles northwest of the City of Palm Springs and is under the jurisdiction of the SCAQMD. **AIR QUALITY Table 3** lists the attainment and non-attainment status of the district for each criteria pollutant for both the federal and state ambient air quality standards.

AIR QUALITY Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	California Standard	Federal Standard
Ozone (O_3)	1 Hour	0.09 ppm (180 μg/m^3)	--
	8 Hour	0.07 ppm (140 μg/m^3)	0.075 ppm (147 μg/m^3)
Respirable Particulate Matter (PM10)	24 Hour	50 μg/m^3	150 μg/m^3
	Annual*	20 μg/m^3	--
Fine Particulate Matter (PM2.5)	24 Hour	--	35 μg/m^3
	Annual*	12 μg/m^3	15 μg/m^3
Carbon Monoxide (CO)	1 Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)
	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
Nitrogen Dioxide (NO_2)	1 Hour	0.18 ppm (338 μg/m^3)	0.100 ppm**
	Annual*	0.030 ppm (56 μg/m^3)	0.030 ppm (56 μg/m^3)
Sulfur Dioxide (SO_2)	1 Hour	0.25 ppm (655 μg/m^3)	--
	3 Hour	--	0.5 ppm (1300 μg/m^3)
	24 Hour	0.04 ppm (105 μg/m^3)	0.14 ppm (365 μg/m^3)
	Annual*	--	0.03 ppm (80 μg/m^3)
Lead	30 Day Average	1.5 μg/m^3	--
	Calendar Quarter	--	1.5 μg/m^3
Sulfates	24 Hour	25 μg/m^3	--
Hydrogen Sulfide (H_2S)	1 Hour	0.03 ppm (42 μg/m^3)	--
Vinyl Chloride (chloroethene)	24 Hour	0.010 ppm (26 μg/m^3)	--
Visibility Reducing Particulates	8 hours	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.	--

* Annual Arithmetic Mean;
**Three-year average of 98th percentile daily maximum 1-hour values, scheduled to become effective April 12, 2010. This project is not subject to this new standard as discussed in the text.

Source: CARB 2007b.

Ambient air quality data has been collected extensively in the air basin. **AIR QUALITY Table 4** lists a summary of maximum ambient measurements for the years 1999 through 2005 at the monitoring stations closest to the project site.

Comparison of the values in **AIR QUALITY Table 4** to the most restrictive AAQS in **AIR QUALITY Table 2** clearly shows that ozone, PM10, and PM2.5 continue to violate applicable standards while CO, NO_2 and SO_2 do not violate the standards. However, the new federal short-term NO_2 standard is not evaluated because the application for this project was submitted well before this new standard was proposed for adoption, the

EPA has not developed a dispersion model post-processor to calculate the statistical compliance with the new standard, and a determination of the air basin attainment status is not scheduled until January 2012.

AIR QUALITY Table 3
Attainment / Non-Attainment Classification
South Coast Air Quality Management District (SCAQMD)

Pollutants	Federal Classification	State Classification
Ozone	**Non-Attainment**	**Non-Attainment**
PM10	**Non-Attainment**[1]	**Non-Attainment**
PM2.5	Unclassifiable/Attainment	Unclassified
CO	Attainment	Attainment
NO_2	Attainment [2]	Attainment
SO_2	Attainment	Attainment

1. The AQMD and CARB Governing Boards have already approved the the Salton Sea Air Basin (SSAB) PM10 Redesignation and Maintenance Plan (RMP) for submittal to EPA for inclusion into the SIP. However, the area is still classified as non-attainment for Federal PM10 standards.
2. Attainment status for the new federal 1-hour NO_2 standard is scheduled to be determined by January 2012.

Source: CARB 2006a

AIR QUALITY Table 4
Criteria Pollutant Summary
Maximum Short Term Ambient Concentrations (ppm or µg/m³)

Pollutant	Averaging Period	Units	2001	2002	2003	2004	2005	2006	2007	Limiting AAQS
Ozone	1 hour	ppm	0.14[a]	0.14[a]	0.14[a]	0.13[a]	0.14[a]	0.13[a]	0.13[a]	0.09
Ozone	8 hour	ppm	0.11[a]	0.13[a]	0.11[a]	0.11[a]	0.12[a]	0.11[a]	0.10[a]	0.07
PM10[d]	24 hours	µg/m³	149[b]	139[b]	124[b]	83[b]	106[b]	122[b]	211[b,1]	50
PM2.5[e]	24 hours	µg/m³	44.7[a]	42.3[a]	26.8[b]	28.5[b]	44.4[b]	24.8[a]	20.5[a]	35
CO	1 hour	ppm	2[a]	2[a]	3[a]	2[a]	2[a]	2[a]	1.5[a]	20
CO	8 hour	ppm	1.5[b]	1.2[a]	1.3[a]	1.0[a]	0.8[a]	1.0[a]	0.8[a]	9.0
NO_2	1 hour	ppm	0.08[a]	0.10[a]	0.06[a]	0.07[a]	0.10[a]	0.09[a]	0.06[a]	0.18
SO_2	1 hour	ppm	0.02[c]	0.03[c]	0.02[c]	0.02[c]	0.01[c]	0.01[c]	0.01[c]	0.25
SO_2	24 hour	ppm	0.01[c]	0.01[c]	0.01[c]	0.02[c]	0.004[c]	0.004[c]	0.004[c]	0.04

Note: a) Coachella Valley 1: Palms Spring Fire Station Ambient Air Quality Monitoring Station
b) Coachella Valley 2: Indio-Jackson Street Ambient Air Quality Monitoring Station
c) Riverside-Rubidoux Ambient Air Quality Monitoring Station
d) Maximum PM10 concentration based on California monitoring methodology.
e) Maximum PM2.5 concentration based on national monitoring methodology.
1) This data may be excluded in accordance with EPA's National Event Policy. The SCAQMD has requested this exclusion as part of their Redesignation and Maintenance Plan (RMP) for submittal to EPA for inclusion into the SIP.

Source: CARB 2007a

Attainment Criteria Pollutants

Although both NO_2 and SO_2 are classified as in attainment with all state and federal AAQS, they remain of significant concern since they are precursors to PM10, and NO_2

is a precursor to ozone. Because NO_2 and SO_2 are precursors to non-attainment pollutants, the SCAQMD will require full offset mitigation for both.

Nitrogen Dioxide (NO_2)

Most combustion activities and engines emit significant quantities of nitrogen oxides (NOx), a term used in reference to combined quantities of nitrogen oxide (NO) and NO_2. Most of the NOx emitted from combustion sources is NO. Although only NO_2 is a criteria pollutant, NO is readily oxidized in the atmosphere into NO_2. In urban areas, the ozone concentration level is typically high. That level will drop substantially at night as NO is oxidized into NO_2, and increase again in the daytime as sunlight disassociates NO_2 into NO and ozone. This reaction explains why urban ozone concentrations at ground level can be relatively low near large NO emission sources, while downwind rural areas (without sources of fresh NO emissions) are exposed to higher ozone concentrations as arriving NO_2 dissociates into NO and ozone in the presence of sunlight.

Sulfur Dioxide (SO_2)

Sulfur dioxide is typically emitted as a result of the combustion of fuels containing sulfur. In significant ambient quantities, SO_2 can lead to acid rain and sulfite particulate formation. Natural gas contains very little sulfur and consequently produces very few SO_2 emissions when combusted. By contrast, fuels high in sulfur, such as lignite (a type of coal), emit large amounts of SO_2 when combusted. Sources of SO_2 emissions within the basin come from every economic sector and include a wide variety of gaseous, liquid and solid fuels.

Carbon Monoxide (CO)

CO is generated from most combustion engines and other combustion activities. CO is considered a local pollutant, as it will rapidly oxidize to carbon dioxide. It is thus found in high concentrations only near the source of emissions. Automobiles and other mobile sources are the principal source of CO emissions. High levels of CO emissions can also be generated from fireplaces and wood-burning stoves. Industrial sources, including power plants, typically constitute less than 10 percent of the ambient CO levels in the South Coast region (CARB 2006c).

The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime late in the afternoon, persist during the night and may extend one or two hours after sunrise. Because the mobile sector (ships, cars, trucks, busses and other vehicles) is the main source of CO, ambient concentrations of CO are highly dependent on traffic patterns. Carbon monoxide concentrations in the state have declined significantly due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state. Today, all the counties in California are in compliance with the state and federal CO AAQS.

Non-Attainment Criteria Pollutants

The following sections provide background information for the non-attainment criteria pollutants: ozone, PM10, and PM2.5.

Ozone (O_3)

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between precursor air pollutants. The primary ozone precursors are NOx and volatile organic compounds (VOC), both of which interact in the presence of sunlight to form ozone.

The SCAQMD is designated as severe-17[1] non-attainment for ozone (the second worst possible classification), meaning that the South Coast air basin ambient ozone design concentration is 0.280 ppm or above and it did not reach attainment before 2007. Efforts to achieve ozone attainment typically focus on controlling the ozone precursors NOx and VOC. SCAQMD-published state implementation plans (SIP) rely on the CARB to control mobile sources, the U.S. EPA to control emission sources under federal jurisdiction, and SCAQMD to control local industrial sources. Through these control measures, California and the SCAQMD are required to reach attainment of the federal ozone ambient air quality standard by 2021 (2013 in the Coachella Valley).

Exceedances of the national and state ozone ambient air quality standards occur in the region both up wind and downwind of the project site. **AIR QUALITY Figure 1** shows the number of days each year with exceedances of the state 1-hour ozone standard at three representative monitoring sites. The three monitoring sites were chosen to represent three distinct parts of the air shed: coastal region, proposed project region, and inland region.

The proposed project area is represented in **AIR QUALITY Figure 1** by the Palm Springs monitoring station. The Redlands monitoring station is in an area very near the inland regions of the SCAQMD. The data clearly shows the characteristic trend to higher ambient ozone concentrations farther away from the coast, due to prevailing onshore airflow. **AIR QUALITY Figure 2** provides a graphical representation of this effect for a single year, showing how the onshore airflow pushes pollution inland and thus focuses regional violations away from the coast.

Though there are a significant number of exceedances of the ozone ambient air quality standards throughout the South Coast air basin, it is important to consider the improvements that have occurred in recent years. The SCAQMD leads the nation in air quality management methods and regulatory programs. These programs have significantly improved the air quality in spite of the growing population and industrial and commercial enterprises. **AIR QUALITY Figure 1** clearly shows the improvements in

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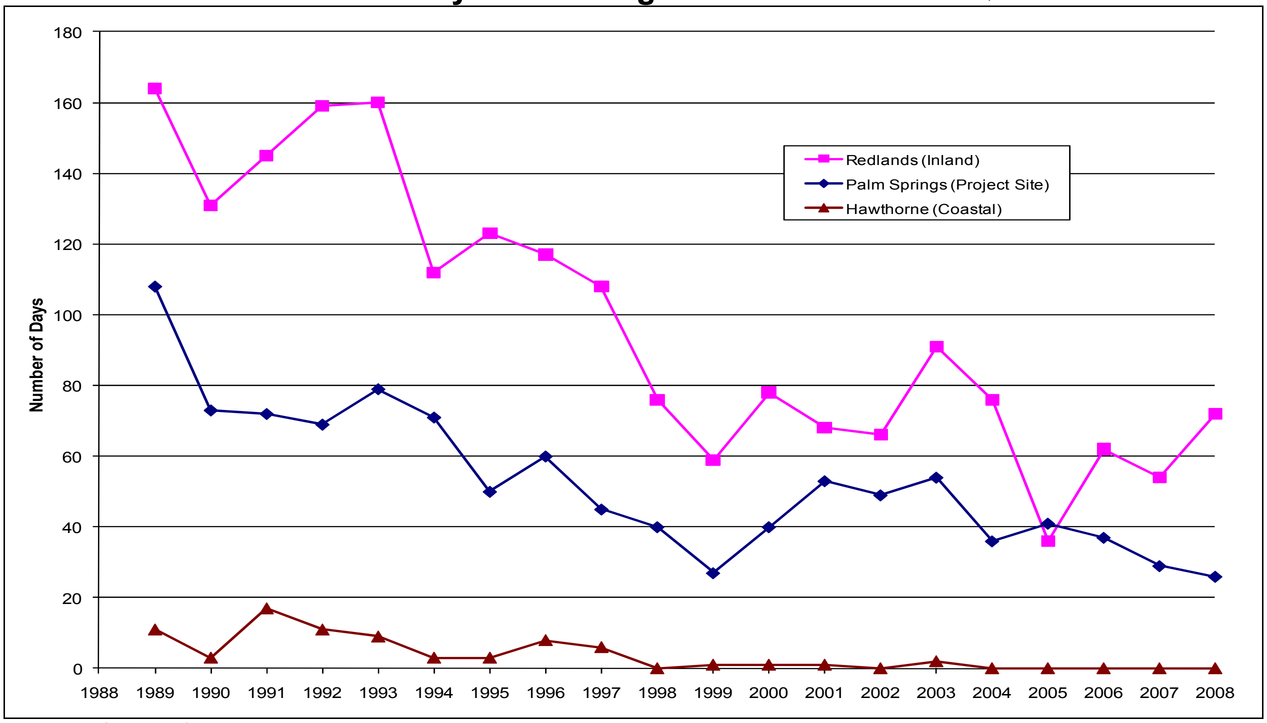
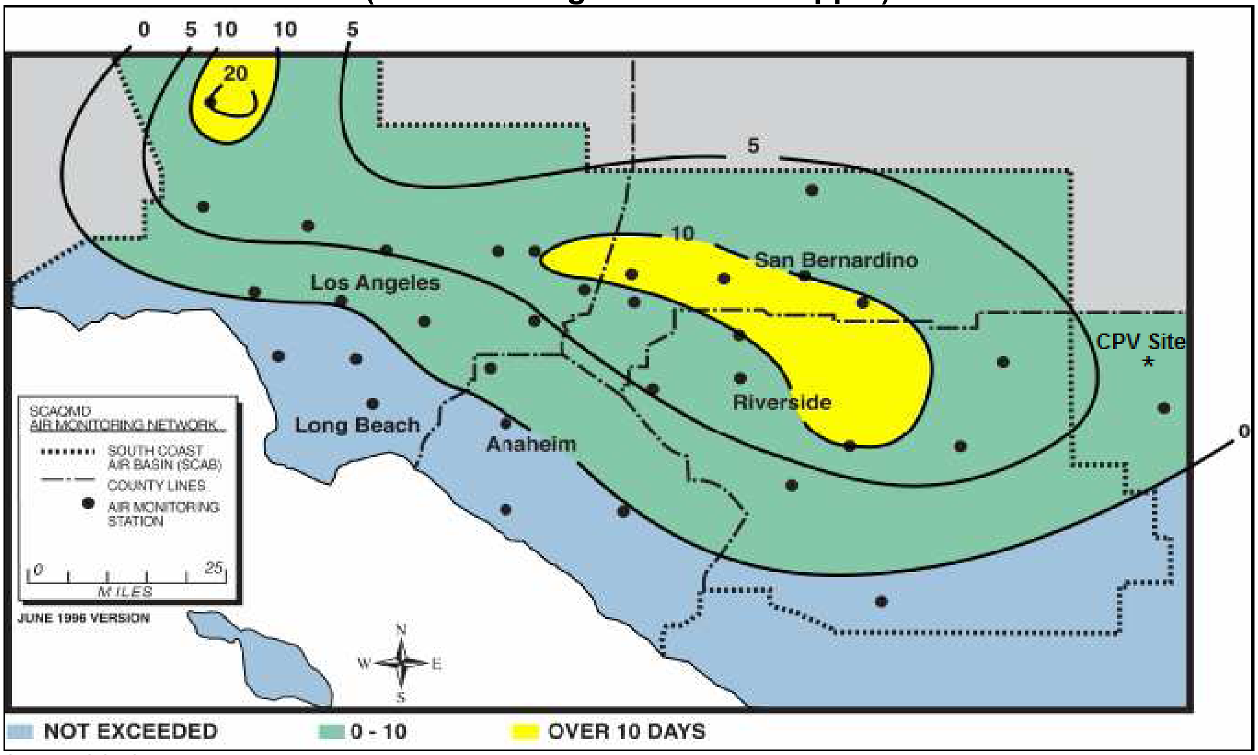
[1] Areas defined as severe-17 have an 8-hr ozone design value of 0.127 up to but not including 0.187 ppm; with a maximum of 17 years to attain the federal 8-hour ozone standard.

AIR QUALITY Figure 1
OZONE 1989-2008
Number of Days Exceeding the State 1-Hour AAQS



Source: CARB 2008a, 2010

AIR QUALITY Figure 2
OZONE – 2006 Number of Days Exceeding 1-Hour Federal Standard
(1-hour average ozone > 0.12 ppm)



Source: SCAQMD 2006

ozone air quality levels over the past 16 years in the South Coast air basin, especially in the intermediate region near the proposed project site. As shown in **AIR QUALITY Figure 1**, in 2003 there was a slight increase over prior years in the number of exceedances recorded. Since 2003 however, the downward trend has returned, approaching the 2002 lower number of exceedances. However, the trends for Redlands and Palm Springs suggest these areas will not meet the original federal attainment date of 2010, but instead will meet federal attainment in 2013 for the Coachella Valley and 2021 for the remainder of the South Coast air basin.

Respirable Particulate Matter (PM10)

PM10 is generated both directly from a combustion process and generated downwind of a source when various emitted precursor pollutants chemically interact in the atmosphere to form solid precipitates. These solids are called secondary particulates, because they are not directly emitted, but are still generated as a consequence of facility emissions. Gaseous emissions of pollutants such as NOx, SO_2 and VOC from turbines, and ammonia (NH_3) from NOx control equipment can form particulate nitrates, sulfates, and organic solids.

San Bernardino County (but not the entire South Coast air basin) has been designated a non-attainment area for the federal 24-hour and annual PM10 ambient air quality standards. The SCAQMD has recently taken action to have the Salton Sea Air Basin (SSAB), which includes the project site, redesignated as attainment for PM10. The

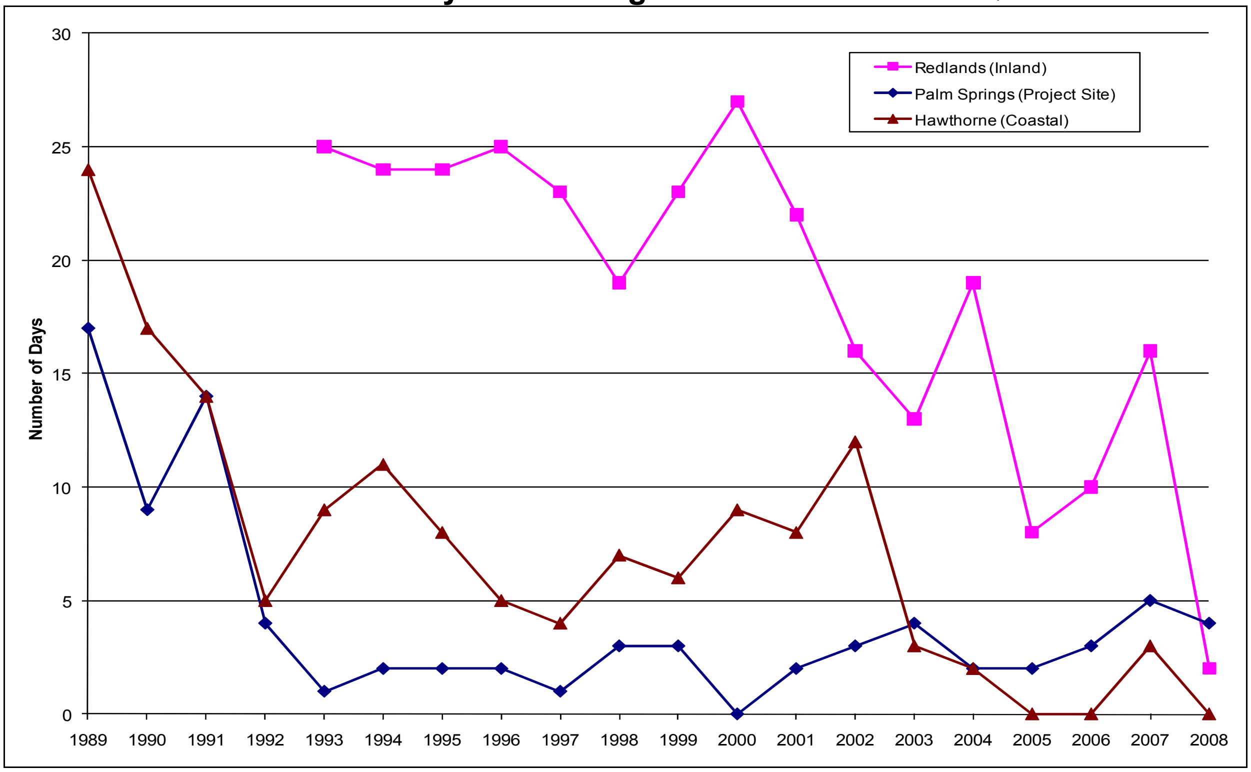
SCAQMD and CARB Governing Boards have already approved the SSAB PM10 Redesignation and Maintenance Plan (RMP) for submittal to EPA for inclusion in the SIP. However, the area is still classified as non-attainment for Federal PM10 standards until EPA approves the SIP, which would likely occur within one to two years. The South Coast air basin (including a portion of San Bernardino County within the basin) has been designated as a non-attainment zone for the state 24-hour and annual PM10 ambient air quality standards. **AIR QUALITY Figure 3** below shows the number of days each year on which exceedances of the state 24-hour PM10 standard occurred for three representative monitoring regions: coastal, project site, and inland. The data shows some improvement over the period, but overall the PM10 situation remains a concern.

Fine Particulate Matter (PM2.5)

PM2.5, a subset of PM10, consists of particles with an aerodynamic diameter less than or equal to 2.5 microns. Particles within the PM2.5 fraction penetrate more deeply into the lungs, and can be much more damaging by weight than larger particulates. PM2.5 is primarily a product of combustion and includes nitrates, sulfates, organic carbon (ultra fine dust) and elemental carbon (ultra fine soot). **AIR QUALITY Figure 4** below shows the number of days each year on which exceedances of the new federal 24-hour PM2.5 standard of 35 $\mu g/m^3$ (there is no separate short-term state standard) occurred for three representative monitoring regions: coastal, project site, and inland.

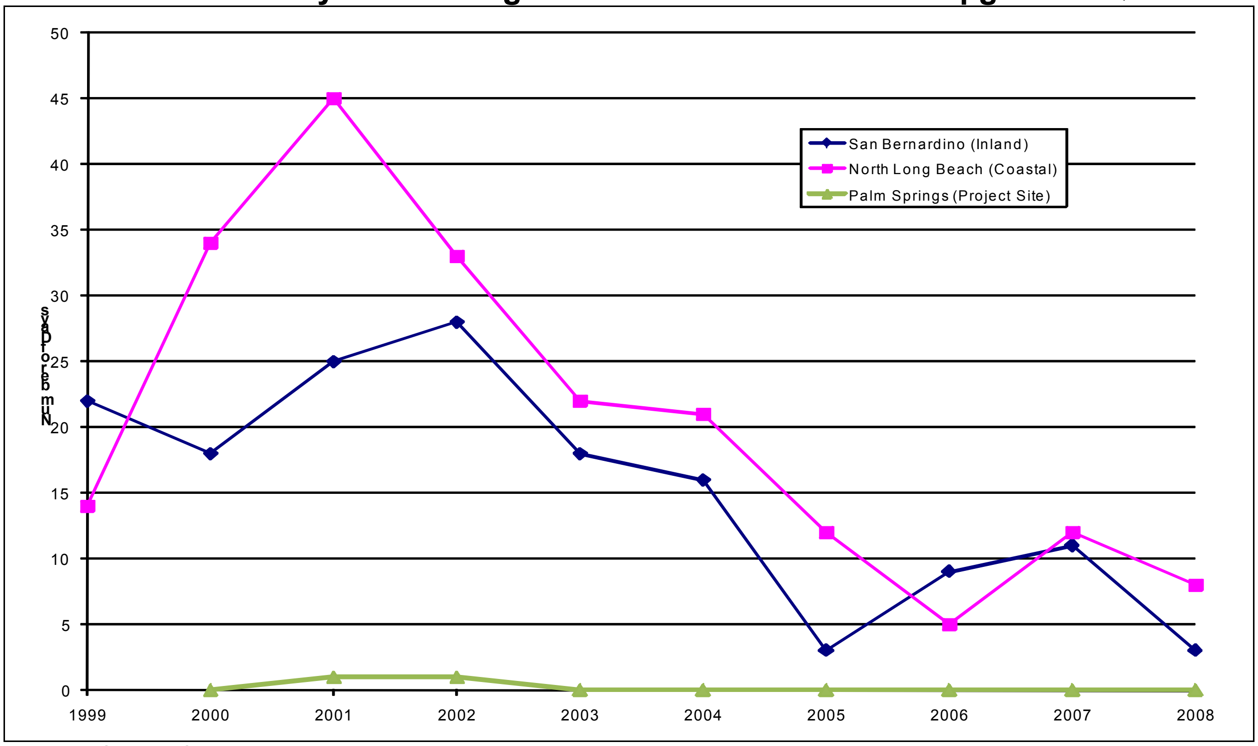
The highest concentrations of PM2.5 in the South Coast air basin occur within the counties of San Bernardino and Riverside (similarly to PM10), but also extend west toward downtown Los Angeles. This effect is shown graphically in **AIR QUALITY Figure 5** below.

AIR QUALITY Figure 3
PM10 1989-2008
Number of Days Exceeding the State 24-Hour AAQS



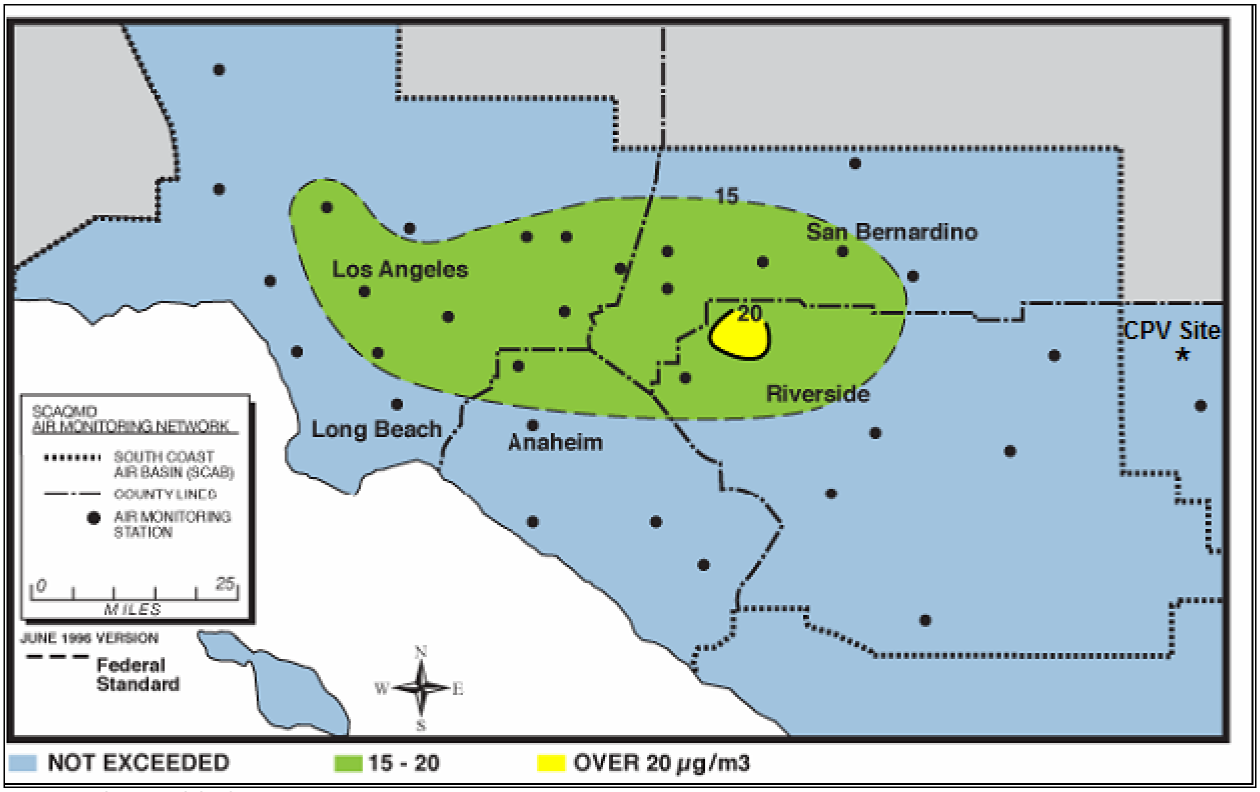
Source: CARB 2008a, 2010.

AIR QUALITY Figure 4
PM2.5 1999-2008
Number of Days Exceeding the New Federal 24-Hour 35 µg/m³ AAQS



Source: CARB 2008a, 2010.

AIR QUALITY Figure 5
PM2.5 – 2006
Annual Arithmetic Mean, µg/m³



Source: SCAQMD 2006

PM2.5 standards were first adopted by U.S. EPA in 1997, and were upheld by the United States Supreme Court in 2001 over a challenge from the American Trucking Association (ATA et al). Though South Coast air basin is designated as non-attainment for all state and federal PM2.5 AAQS, the SCAQMD has not yet finished preparing a PM2.5 SIP. The SCAQMD has submitted a PM2.5 SIP, and once the plan is approved by USEPA, the SCAQMD will prepare revised NSR rules that will likely require offsetting of PM2.5 emissions. The SCAQMD is thus unlikely to address PM2.5 in their rules within the schedule of this proposed project. Staff, however, has a responsibility under the California Environmental Quality Act (CEQA to address PM2.5 emissions, and will do so, taking into consideration the fact that the proposed project region is not in attainment with adopted PM2.5 standards.

Existing Ambient Air Quality Summary

Based on the above analysis of background ambient air quality, staff recommends the use of the background ambient air pollutant concentrations in **AIR QUALITY Table 5** for the purpose of modeling and evaluating potential ambient air quality impacts from the proposed project.

AIR QUALITY Table 5
Staff Recommended Background Concentrations (μg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour	174.8[a]	338	52%
	Annual	24.5	56	44%
CO	1 hour	2,645[a]	23,000	11%
	8 hour	944.4[a]	10,000	9%
PM10	24 hour	211[b,1]	50	**422%**
	Annual	54.9	20	**274%**
PM2.5	24 hour	44.4[b]	35	**127%**
	Annual	10.8[2]	12	90%
SO_2	1 hour	62.9[c]	655	9%
	24 hour	39.4[c]	105	37%
	Annual	10.7[c]	80	13%

Note: a) Coachella Valley 1: Palms Spring Fire Station Ambient Air Quality Monitoring Station
b) Coachella Valley 2: Indio-Jackson Street Ambient Air Quality Monitoring Station
c) Riverside-Rubidoux Ambient Air Quality Monitoring Station
1) This data may be excluded by EPA and ARB in accordance with EPA's National Event Policy (ARB has approved exclusion, while EPA is currently reviewing the revised SIP and proposed redesignation of the basin to attainment). In that case, staff recommends using a value of 122 μg/m^3, the next highest value.
2) Federal annual mean, there is insufficient data for the state annual mean.

Source: CARB 2007a

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The proposed CPV Sentinel Energy Project (CPV Sentinel) would be a nominally rated 850 megawatt (MW) electrical generating facility that would encompass 37 acres of land situated within unincorporated Riverside County, California, adjacent to the Palm Springs northern city limits. The proposed CPV Sentinel project's major air pollutant emissions sources are:

Eight General Electric (GE) LMS100 combustion turbine generators (CTG).

Oxidation catalyst and selective catalytic reduction (SCR) equipment.

Eight single cell mechanical draft cooling towers.

A 240 brake horsepower (bhp) diesel emergency fire pump engine (Tier III).

Linear Construction Elements:

- 2.6 mile long natural gas pipeline extending from the existing Indigo Energy Facility,
- 2,300 foot long, 230-kV transmission line connecting to the existing Devers substation,
- 3,200 foot long road extending off Dillon Road to the project site and associated intersection widening at Dillon Road and the site access road, and

- o 3,200 foot long potable water supply pipeline extending off Dillon Road to the project site.

The potential emissions from the facility are classified in three categories: construction, initial commissioning, and operation.

Construction Emissions

Facility construction is expected to take about 18 months. The power plant project construction consists of three major areas of activity: 1) the civil/structural construction 2) the mechanical construction, and 3) the electrical construction. The projected maximum daily and annual emissions, based on the highest monthly emissions over the entire construction period, are shown in **AIR QUALITY Table 6**.

AIR QUALITY Table 6
Estimated Maximum Construction Emissions (over 18 months)

	NOx	SO_2	CO	VOC	PM10	PM2.5
Maximum Daily Emissions (lb/day)	110.4	0.1	63.6	18.6	13.6	7.6
Maximum Annual Emissions (tons/year)	14.7	0.02	8.6	2.6	2.4	1.2

Source: CPV 2007a

The largest percentage of these construction emissions will likely be emitted during the first phase of project site activity, mostly due to earth moving, grading activities, large equipment operations, underground utility installation, and as building erection occurs. These types of activities require the use of large earth moving equipment, which generate considerable direct combustion emissions, along with fugitive dust emissions. The mechanical construction phase includes the installation of the heavy equipment such as the gas turbines, compressors, pumps, and associated piping. Although not a large fugitive dust generation activity, the use of large cranes to install such equipment generates significantly more direct combustion emissions than other construction equipment. Lastly, the electrical construction phase involves installation of transformers, switching gear, instrumentation, and all wiring; and is a relatively small source of emissions in comparison to the earlier construction activities.

Initial Commissioning Emissions

New power generation facilities must go through an initial firing and commissioning phase before being deemed commercially available to generate power. During this period, emissions may exceed permitted levels due to numerous startups and shutdowns, periods of low load operation, lack of pollution control equipment during test periods and other testing required before emission control systems are fine-tuned for optimum performance.

The applicant anticipates six distinct commissioning phases (CPV 2007a), with a total of approximately 200 hours of operation per turbine without full emissions controls, and a further 300 hours per turbine of commissioning tuning under full emissions control. **AIR QUALITY Table 7** presents the predicted maximum short term emissions of NOx, CO, and VOC. PM10 and SO_2 emissions are not included here since they are proportional to fuel use, and fuel use (and thus PM10 and SO_2 emissions) during commissioning is equal to or lower than during full load operations.

AIR QUALITY Table 7
Estimated Maximum Initial Commissioning Emissions

	NOx	CO	VOC
Maximum Hourly Emissions (lb/hour)	168	305	15

Source: CPV 2007a

Operation Emission Controls

NOx Controls

Each combustion turbine generator (CTG) exhaust will be treated by an ammonia injected selective catalytic reduction (SCR) system before release to the atmosphere. SCR refers to a process that chemically reduces NOx to elemental nitrogen and water vapor by injecting ammonia into the flue gas stream in the presence of a catalyst and excess oxygen. The process is termed selective because the ammonia preferentially reacts with NOx rather than oxygen. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or noble metals are also used. Regardless of the type of catalyst used, efficient conversion of NOx to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream and a catalyst surface large enough to ensure sufficient time for the reaction to take place.

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NOx formed during combustion. One method has been the injection of steam or water into the combustor cans to reduce combustion temperatures and the formation of thermal NOx, which is the primary source of NOx emissions from a CTG. This method, which has been employed for many years and is well understood, has been proposed for the GE LMS100 turbines for this project.

VOC and CO Controls

VOC and CO emissions will be controlled in the CTG combustor and by the use of an oxidation catalyst. In an oxidation catalyst system, organic compounds and CO chemically react with excess oxygen to form nontoxic carbon dioxide and water. Unlike the SCR system for reducing NOx, an oxidation catalyst does not require any additional chemicals.

PM10 and SO_2 Controls

The exclusive use of pipeline quality natural gas, an inherently clean fuel that contains very little noncombustible solid residue, will limit the formation of SO_2 and PM10. For safety purposes, natural gas contains a small amount of a sulfur-based scenting compound known as mercaptan which produces sulfur dioxide emissions when combusted. However, in comparison to other fuels used in modern thermal power plants, such as fuel oil or coal, the amount of sulfur dioxide produced from the combustion of natural gas is very low. Like SO_2, the emission level of PM10 from natural gas combustion is also very low compared to the combustion of fuel oil or coal. It is assumed in this assessment that the natural gas has a maximum short term sulfur content of 0.75 gr/100scf (grains per 100 cubic feet at standard temperature and pressure), based on Southern California Gas Company rules for pipeline quality natural gas, and an annual average sulfur content of 0.25 gr/100scf, based on a monthly gas sampling requirement at the CPV Sentinel project.

The majority of the emissions from cooling towers are pure water vapor; however, a small amount of liquid water can escape and is known as "drift". Cooling tower drift consists of a mist of very small water droplets, which can generate particulate matter that originates from the dissolved solids in the circulating water once the water droplets evaporate. To limit these particulate emissions, cooling towers use drift eliminators to capture these water droplets, and cooling tower operators are required to monitor the total dissolved solids (TDS) in the cooling tower recirculation water to ensure that it does not exceed a SCAQMD-specified value. The applicant intends to use drift eliminators on the cooling towers designed to limit drift to 0.0005 percent of the circulating water volume per unit time. This limit is included as part of Condition of Certification **AQ-SC11**.

Proposed Operation Emissions

Per the applicant's request, all emissions calculations and limitations are based on an assumed availability of 2,628 hours per year, plus 300 startups and 300 shutdowns for all eight CTG Units (CPV 2007a, CPV 2009). The CTGs will burn only pipeline natural gas; there are no provisions for an alternative or back-up fuel.

The proposed maximum criteria air pollutant emissions are based entirely on vendor data for the GE LMS100 turbine and the data presented in the SCAQMD Preliminary Determination of Compliance (SCAQMD 2007a). **AIR QUALITY Table 8** lists the maximum 1-hour emissions from each piece of equipment on the proposed project site.

AIR QUALITY Table 8
Equipment Maximum Short-Term Emissions Rates
(pounds per hour [lb/hr], except as noted)

Process Description	NOx	SO_2	CO	VOC	PM10
CTG Startup (per turbine) (25 minute startup, **lb/1-hr event**)	24.86	0.17	16.89	4.26	2.08
CTG Full Load (per turbine)	7.95	0.63	7.74	2.21	5.00
CTG Shutdown (per turbine) (10 minute shutdown, **lb/1-hr event**)	6.0	0.02	35.0	3.0	0.86
Fire Pump Engine	2.54	0.001	0.31	0.05	0.07
Cooling Towers (all 8 cells)	0	0	0	0	0.79

Source: CPV 2007a, FDOC Reference

Based on these emissions rates, the maximum possible 1-hour emissions from the entire facility are shown in **AIR QUALITY Table 9**. The estimated emissions for the CTGs depend on the operational assumptions. For example, the NOx and VOC emissions from the CTGs are a maximum when all eight CTGs startup and operate at full load. Contrast that with the maximum for CO emissions from the CTGs, which occurs when all eight CTGs are operating at full load and then shutdown. Finally, the PM10 and SOx emissions from the CTGs are at a maximum when the CTGs are at full load.

AIR QUALITY Table 9
Facility Maximum 1-hour Emissions
(pounds per hour [lb/hr])

Process Description	NOx	SO_2	CO	VOC	PM10
8 CTGs	236.0[a]	5.0[c]	331.6[b]	44.4[a]	40.0[c]
Fire Pump Engine[d]	1.55	0.002	0.36	0.04	0.05
Cooling Towers (all 8 cells)	---	---	---	---	0.52
Total Maximum 1-hour Emissions	237.5	5.0	332.0	44.4	40.6

[a] Assumes all 8 CTGs startup and operate for the balance of 1 hour.
[b] Assumes all 8 CTGs operate at full load and shutdown for the balance of 1 hour.
[c] Assumes all 8 CTGs operate at full load for the duration of 1 hour.
[d] The Fire Water Pump will utilize a Tier III engine and is assumed to test for the entire hour.

Source: CPV 2007a, CPV 2009, SCAQMD 2010.

In general, higher emissions of NOx, VOC and CO will occur during the startup and shutdown of a large CTG than during operation because the turbine combustors are designed for maximum efficiency during full load, steady state operation. During startup, combustion temperatures and pressures change rapidly, resulting in less efficient combustion and higher emissions. Also, flue gas emission controls (the catalysts discussed above), operate most efficiently when a turbine operates at or near full load temperatures.

The maximum daily emission rates for NOx, CO, and VOC were conservatively estimated for each power train based on 22 hours and 49 minutes of operation, two 25 minute startups, and two 10.3 minute shutdowns per turbine. The maximum daily emission rates for PM10 and SO_2 were based instead on 24 hours of full load operation, since PM10 and SO_2 emissions are proportional to fuel use. The total project maximum daily emissions are then conservatively estimated as the sum of the emissions from all eight power trains, the cooling tower, and a single hour of emergency fire pump operation for required testing purposes. These estimates are presented in **AIR QUALITY Table 10** below.

The expected maximum annual emissions for the total facility are summarized in **AIR QUALITY Table 11**. The calculations assume 2,628 hours per year, plus 300 startups and 300 shutdowns for all 8 CTG Units. The facility annual emissions further assume 2,628 hours per year for all 8 of the single cell cooling towers. The emergency fire pump testing is expected to occur for one hour each week and the diesel generator testing is expected to occur one hour each month. In addition, the calculations for annual SO_2

emissions assume annual average fuel sulfur content of 0.25 gr/100 scf that is required by Southern California Gas Company.

AIR QUALITY Table 10
Project Maximum Daily Emissions
(pounds per day [lb/day])

Process Description	NOx	SO_2	CO	VOC	PM10
8 CTGs	1,946.0[a]	121.0[b]	2,244.1[a]	519.9[a]	960.0[b]
Fire Pump Engine [c]	1.55	0.00	0.36	0.04	0.05
Cooling Towers [d]	--	--	--	--	12.50
Total Maximum Daily Emissions	1947.5	121.0	2,244.4	519.9	972.5

[a] Assumes each of 8 CTGs has 2 startups, 2 shutdowns and full load operation for the duration of 24 hours.
[b] Assumes all 8 CTGs operate at full load for 24 hours.
[c] Assumes the Fire Water Pump is tested for one hours each.
[d] Assumes all 8 cells of the cooling towers operate at full load for 24 hours.

Source: CPV 2007a

AIR QUALITY Table 11
Project Maximum Annual Emissions
(pounds per year [lb/yr] and tons per year [tpy])

Process Description	NOx	SO_2	CO	VOC	PM10
8 CTG (tpy)[a]	120.4	6.8	141.2	31.8	56.1
Firewater Pump (lb/yr)[b]	80.3	0.1	18.7	2.1	2.5
Cooling Towers (lb/yr)[d]	--	--	--	--	1,460
Total Maximum Annual Emissions (tpy)	120.5	6.8	141.2	31.8	56.8

[a] Assumes CTG all Units: 2,628 hours of full load operation, 300 startups and 300 shutdowns.
[b] Assumes the Fire Water Pump has 52 1-hour tests.
[d] Assumes the 8 single cell cooling towers operate at full load for 2,628 hours per year

Source: CPV 2007a

Ammonia Emissions

To control NOx emissions from the combustion turbines, ammonia is injected into the flue gas stream as part of the SCR system. In the presence of the catalyst, the ammonia and NOx react to form harmless elemental nitrogen and water vapor. However, not all of the ammonia reacts with the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered from the stacks. These ammonia emissions are known as ammonia slip. It should be noted that a maximum permitted ammonia slip rate only occurs after significant degradation of the SCR catalyst, usually five years or more after commencing operations. At that point, the SCR catalysts are removed and replaced with new catalysts. During the majority of the operational life of the SCR system, actual ammonia slip will be at 10 to 50 percent of the permitted limit. The applicant proposes an ammonia emission limit of five ppm at 15 percent oxygen averaged over one hour. This is consistent with emissions levels used in other projects and is agreed to by staff.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Energy Commission staff assesses four kinds of primary and secondary[2] impacts: construction, operation, closure and decommissioning, and cumulative. Construction impacts result from the onsite and offsite emissions occurring during site preparation and construction of the proposed project. Operational impacts result from the emissions of the proposed project during operation, which includes all of the onsite auxiliary equipment emissions (emergency engine and gasoline tank), the onsite maintenance vehicle emissions, and the offsite employee and material delivery trip emissions. Closure and decommissioning impacts occur from the onsite and offsite emissions that would result from dismantling the facility and restoring the site. Cumulative impacts result from the proposed project's incremental effect, together with other closely related past, present and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and15355.)

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

CEC staff evaluates potential impacts per Appendix G of the CEQA Guidelines (CCR 2006) as appropriate for the project. A CEQA significant adverse impact is determined if potentially significant CEQA impacts cannot be mitigated appropriately through the adoption of Conditions of Certification. Specifically, Energy Commission staff uses health-based ambient air quality standards (AAQS) established by the ARB and the U.S.EPA as a basis for determining whether a project's emissions would cause a significant adverse impact under CEQA. The standards are set at levels that include a margin of safety and are designed to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants. Staff evaluates the potential for significant adverse air quality impacts by assessing whether the project's emissions of criteria pollutants and their precursors (NOx, VOC, PM10 and SO2) could create a new AAQS exceedance (emission concentrations above the standard), or substantially contributes to an existing AAQS exceedance.

Staff evaluates both direct and cumulative impacts. Staff would find that a project or activity would create a direct adverse impact when it causes an exceedance of an AAQS. Staff would find that a project's effects are cumulatively considerable when the project emissions in conjunction with ambient background, or in conjunction with reasonably foreseeable future projects, substantially contribute to ongoing exceedances of an AAQS. Factors considered in determining whether contributions to ongoing exceedences are substantial include:

1. the duration of the activity causing adverse air quality impacts;

2. the magnitude of the project emissions, and their contribution to the air basin's emission inventory and future emission budgets established to maintain or attain compliance with AAQS;

3. the location of the project site, i.e., whether it is located in an area with generally good air quality where non-attainment of any ambient air quality standard is primarily or solely due to pollutant transport from other air basins;

4. the meteorological conditions and timing of the project impacts, i.e., do the project's maximum modeled pollutant impacts occur when ambient concentrations are high (such as during high wind periods, or seasonally);

5. the modeling methods, and how refined or conservative the impact analysis modeling methods and assumptions were and how that may affect the determined adverse impacts;

6. the project site location and nearest receptor locations; and whether the identified adverse impacts would also occur at the maximum impacted receptor location; and,

7. potential for future cumulative impacts; and whether appropriate mitigation is being recommended to address the potential for impacts associated with likely future projects.

DIRECT/INDIRECT IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants will be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a new emissions source. These models consist of a complex series of mathematical equations, which are repeatedly evaluated by a computer for many different sets of ambient conditions and input parameters. The model results are often described as a maximum theoretical concentration of pollutant in the air to which people could be exposed, or units of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

In general, the input parameters for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data, and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Wintec Wind Energy facility, and background criteria pollutant measurements from a number of SCAQMD-maintained ambient monitoring stations in the vicinity of the project site (CPV 2007a). A receptor grid, or points where modeled concentrations will be calculated, was also placed around the facility, starting at the property boundary/fence line, and extending several miles in all direction.

The applicant used the U.S. EPA-approved American Meteorological Society/Environment Protection Agency Regulatory Model Improvement Committee Model (AERMOD), as both a screening and refined model to estimate the direct impacts of the project's NOx, PM10, CO, and SO_2 emissions resulting from project construction and operation. A description of the modeling analysis and its results are provided in the Application for Certification (AFC) (CPV 2007a) and the amendment to the SCAQMD permit application (CPV 2009). AERMOD is a generally accepted model for this type of project, and the meteorological input data is sufficient.

Staff added the applicant's modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute substantially to an existing violation.

The U.S. Environmental Protection Agency (U.S. EPA) is implementing a new, 1-hour NO_2 standard that is scheduled to become effective April 12, 2010. This new standard is expressed as a 3-year average of the 98th percentile of the *daily maximum* 1-hour concentration (i.e., the 8th highest of daily highest 1-hour concentrations). The new standard requires "first tier" ambient NO_2 monitoring near major roadways as defined in the implementing language and "second tier" monitoring for regional NO_2 concentrations. Although U.S. EPA has specified NO_2 monitoring requirements and a schedule for determining attainment status relative to this new standard (January 2012), it has not yet developed modeling software to generate the statistics in a form that can be used in a compliance demonstration. Therefore, the analyses described below do not include this project's impact on the new federal 1-hour NO_2 standard and the conclusions reached likewise do not include this impact.

Construction Impacts and Mitigation

Construction Impact Analysis

The construction air quality impact analyses prepared by the applicant considered both fugitive dust generated from the construction activity and combustion emissions produced by construction equipment. As a conservative assumption, this includes the following major sources (CPV 2007a):

- Dust entrained during site preparation and finish grading;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations;
- Dust caused by wind erosion of areas disturbed during construction;

- Exhaust from diesel construction equipment used for site preparation, grading, excavation, and construction;
- Exhaust from water trucks used for onsite paved and unpaved road fugitive dust control;
- Exhaust from diesel powered welding machines, electric generator, air compressors, and water pumps;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel, and construction supplies to the site; and
- Exhaust from automobiles used by workers to commute to the construction site.

The applicant assessed the maximum 24-hour impacts using the emission rates for the month of maximum activity, and assessed the annual impacts using the average emissions for the entire construction period. They added the results of this modeling effort (shown in **AIR QUALITY Table 12** below) to the assumed maximum background values, and compared the combined values to the most restrictive AAQS.

As the modeling results in **AIR QUALITY Table 12** show, the project's construction emissions will not cause a new violation of the NO_2, CO and SO_2 ambient air quality standards, and thus staff does not find these impacts to be significant. Staff believes that the particulate emissions from the construction of the project create a potentially significant impact because they will contribute to existing violations of the annual and 24-hour average PM10 and the 24-hour federal PM2.5 AAQS. Those emissions can and should be mitigated to a level of insignificance. The NO_2 results in **AIR QUALITY Table 12** are not in the form required to evaluate compliance with the new federal 1-hour NO_2 standard. The new federal short-term NO_2 standard is not evaluated because the application for this project was submitted well before this new standard was proposed for adoption, the EPA has not developed a dispersion model post-processor to calculate the statistical compliance with the new standard, and a determination of the air basin attainment status is not scheduled until January 2012.

AIR QUALITY Table 12
Maximum Potential Construction Impacts Before Mitigation (μg/m^3)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
NO_2	1 hour	145.5	174.8	320.3	338	95%
	Annual	7.69	24.5	32.19	56	57%
CO	1 hour	95.3	2,645	2,740.3	23,000	12%
	8 hour	23.1	944.4	967.5	10,000	10%
PM10	24 hour	3.41	211	214.41	50	**429%**
	Annual	1.03	54.9	55.93	20	**280%**
PM2.5	24 hour	1.17	44.4	45.57	35	**130%**
	Annual	0.56	10.8	11.36	12	95%
SO_2	1 hour	0.21	62.9	63.11	655	10%
	24 hour	0.02	39.4	39.42	105	38%
	Annual	0.01	10.7	10.71	80	13%
Includes emissions due to site grading, laydown, building, and pipeline excavation activities.						

Source: CPV 2007a

Construction Mitigation

Applicant's Proposed Mitigation

The applicant proposes a number of mitigation and emissions control measures for use during the construction of the project. The applicant specifically proposes the following measures to control exhaust emissions from heavy diesel construction equipment (CPV 2007a):

Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;

Regular preventive maintenance to prevent emission increases due to engine problems;

Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and

Use of low-emitting gas and diesel engines meeting state and federal emissions standards (Tier I and II) for construction equipment, including, but not limited to, catalytic converter systems and particulate filter systems.

The applicant further proposes the following measures to control fugitive dust emissions during construction of the project:

Use of either water application or chemical dust suppressant application to control dust emissions from on-site unpaved road travel and use of unpaved parking areas;

Use of vacuum sweeping and/or water flushing of paved road surfaces to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;

Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least two feet of freeboard;

Limit traffic speeds on unpaved site areas to 5 mph;

Install sandbags or other erosion control measures to prevent silt runoff to roadways;

Replant vegetation in disturbed areas as quickly as possible;

Use wheel washers or wash tires of all trucks exiting the construction site; and

Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

Staff Proposed Mitigation

Staff agrees with the applicant's proposed mitigation measures. However, because of the predicted significant contribution to both the short- and long-term PM10 and PM2.5 problems, staff believes some additional construction mitigation measures are necessary. These additional measures are detailed below.

Staff has determined that the use of oxidizing soot filters is a viable emissions control technology for all heavy diesel powered construction equipment that does not use an ARB certified low emission diesel engine and ultra-low sulfur content diesel fuel. In addition, staff proposes that prior to the commencement of construction, the applicant provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies the mitigation measures that the applicant will employ to limit air quality impacts during construction. Staff includes proposed staff Conditions of Certification **AQ-SC1** through **AQ-SC5** below to implement the applicant's proposed mitigation measures and staff's additional requirements. These conditions are consistent with conditions of certification adopted in previous licensing cases similar to the CPV Sentinel project. If the proposed project complies with these conditions, it is staff's opinion that the potential for significant air quality impact from the construction of the project is less than significant. Staff recommends that the implementation of all construction mitigation measures be managed by a single person of responsibility, as required in AQ-SC1, to ensure adequate implementation of all mitigation measures.

Operation Impacts and Mitigation

While the construction and commissioning impacts are both relatively short lived, the operation impacts from the project will continue throughout the life of the facility. The operation impacts are thus subject to a more refined level of analysis. The following sections discuss the air quality impacts of project operation during normal full load conditions, including startup and shutdown events, the commissioning phase operations, and fumigation meteorological conditions.

Operation and Startup Impact Analysis

The applicant provided a refined modeling analysis (CPV 2007a, CPV 2009), using the AERMOD model to quantify the potential impacts of the project during both full load operation and startup conditions. The worst case (maximum) results of this modeling analysis are shown in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
Refined Modeling Maximum Impacts During Startup and Operation ($\mu g/m^3$)

Pollutant	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
NO_2	1 hour	139.6[a]	174.8	314.4	339	93%
	Annual	0.46[c]	24.5	24.96	57	44%
CO	1 hour	163.5[a]	2,645	2,808.50	23,000	12%
	8 hour	15.7[a]	944.4	960.1	10,000	10%
PM10	24 hour	10.6[b]	211	221.6	50	**443%**
	Annual	0.43[c]	54.9	55.33	20	**277%**
PM2.5	24 hour	10.6[b]	44.4	55	35	**157%**
	Annual	0.43[c]	10.8	11.23	12	94%
SO_2	1 hour	33.2[b]	62.9	96.1	655	15%
	24 hour	11.0[b]	39.4	50.4	105	48%
	Annual	0.03[c]	10.7	10.73	80	13%

[a] modeled 1-hour average impacts during startup event
[b] modeled 1-hour average impacts during full load operation
[c] Modeled annual operational assumptions for all emitting devices (see AIR QUALITY Table 11).

Source: CPV 2007a

Startup impacts (NOx and CO) are much larger than full load impacts not only because the emissions are greater, but also because the flue gas stream is at a lower velocity and temperature. This reduced emissions velocity means the plume will level off at a lower height and thus have less time to dilute before reaching the ground. Note that the values presented are very conservative, based on worst case startup emission estimates from the turbine manufacturer. Typical startup events are likely to generate significantly fewer emissions and impacts. This analysis is additionally conservative with regard to the assumed background measurements. The assumption is that the highest background measurements from the last four years coincide (in both location and timing) with the maximum project emission impacts. Because such a high background level is unlikely to occur at the same time and location as the maximum impacts from the project, these modeled conditions are considered worst case, conservative, and not likely to occur.

The modeled impact values in **AIR QUALITY Table 13** show that during worst case startup and full load operations, the facility will potentially contribute to the existing

PM10 violations. These violations could exceed 400 percent of the ambient air quality standard. The air dispersion modeling predicted the location of the highest PM10/PM2.5 ambient air quality impacts 600 meters (or just over 1/3 a mile) to the south of the project site. Staff uses the federal and state ambient air quality standards, which are health-based standards, as the indication of possible adverse ambient air quality impacts. Since the project PM10/PM2.5 emission impacts will contribute to an existing exceedance of the PM10 and PM2.5 state and federal ambient air quality standards, staff presumes that these impacts may also contribute to existing human health impacts (generally in the form of respiratory impacts). Thus, staff considers the project PM10/PM2.5 emission impacts to be significant if left unmitigated.

Since the project's impacts alone do not cause a violation of any NO_2, CO, or SO_2 ambient air quality standards under such conservative assumptions, staff concluded that the project impacts for those pollutants are insignificant. Although the direct NO_2 impacts from the CPV Sentinel project do not cause a violation of the NO_2 ambient air quality standard, all NO_2 emissions from the facility will need to be offset with RECLAIM Trading Credits (RTCs) to maintain district wide progress toward attainment with the ozone ambient air quality standards because NO_2 is a precursor emission to ozone formation (see Conditions of Certification **AQ-2** and **AQ-16**). Similarly, the direct SO_2 impacts from the CPV Sentinel project, which do not cause a violation of the SO_2 ambient air quality standards, will need to be offset with Emission Reduction Credits (ERCs) or Priority Reserve Credits (PRCs) to maintain district-wide progress toward attainment with the PM10 ambient air quality standards because SO_2 is a precursor pollutant to secondary PM10/PM2.5 formation. Please see the "Operations Mitigation" section below for a detailed discussion of the proposed mitigation.

Fumigation Modeling Impact Analysis

Surface air is usually stable during the early morning hours before sunrise. During such meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed and diluted. When the sun first rises, the air at ground level is heated, resulting in turbulent vertical mixing (both rising and sinking) of air within a few hundred feet of the ground. Emissions from a stack that enter this turbulent layer of air will also be vertically mixed, bringing some of those emissions down to ground level before significant dispersion occurs and possibly causing abnormally high short term impacts. As the sun continues to heat the ground, this vertical mixing layer becomes thicker over time, and the emissions plume becomes better dispersed. The early morning air pollution event, called fumigation, usually lasts approximately 30 to 60 minutes.

The applicant used the U.S. EPA approved SCREEN3 model (version 96043) for the calculation of the project's fumigation impacts, without a shoreline assumption, since the proposed facility is a significant distance from the nearest shoreline. **AIR QUALITY Table 14** shows the highest modeled fumigation impacts in comparison with the one-hour NO_2, SO_2 and CO standards. Since fumigation impacts will not typically occur for more than a one-hour period, only the impacts on the one-hour standards are shown. The results of the modeling analysis show that fumigation impacts will not violate any of the one-hour standards. Therefore, staff finds the potential ambient air quality fumigation impacts to be less than significant.

AIR QUALITY Table 14
CTG Fumigation Modeling Maximum 1 hour Impacts (μg/m^3)

Pollutant	Modeled Impact from 1 Unit	Modeled Impact from 8 Units	Background	Total Impact	Limiting Standard	Percent of Standard
NO_2	0.7955	6.4	174.8	181.2	338	54%
CO	1.16	9.3	2,645	2654.3	23,000	12%
SO_2	0.061	0.5	62.9	63.4	655	10%

Commissioning Phase Modeling Impact Analysis

The initial commissioning of a power plant refers to the time frame between completion of construction and the consistent production of electricity for sale on the market. Normal operating emission limits usually do not apply during initial commissioning procedures. The CPV Sentinel project will go through several tests during initial commissioning. During the first set of tests, post-combustion controls will not be operational (i.e., the SCR and oxidation catalyst).

Initial commissioning starts with a Full-Speed, No-Load test. This test runs the turbine at approximately 20 percent of its maximum heat input rate. Components tested include the ignition system, synchronization with the electric generator, and the turbine-overspeed safety system. Part Load testing runs the turbines at approximately 60 percent of the maximum heat input rating. During this test, the turbine will be tuned. Full Load testing runs the turbines to their maximum heat input rate. This testing entails further tuning of the turbine. Full Load with partial SCR testing runs the turbines at 100 percent of their maximum heat input rate and operates the SCR ammonia injection grid for the first time at less than maximum injection rate. Finally, Full Load with full SCR testing runs the turbines at their maximum heat input rate and operates the SCR ammonia inject grid at its full capacity. It is during this test that the SCR system will be completely tuned and operated at design levels (i.e., NOx control at 2.0 ppm).

There is little experience to draw from regarding the initial commissioning of the GE LMS100 turbines. The applicant is estimating that it will need approximately 394 hours of actual turbine operation per turbine train for commissioning purposes. The applicant plans to commission all five turbine trains at approximately the same time. The applicant estimates that the maximum NOx emission rate (175 lbs/hr for one turbine) is most likely to occur during the water injection commissioning phase when the water injection will be 50 percent effective and the turbine train will be at 50 percent load. The maximum CO emission rate (255 lbs/hr) will most likely occur when the water injection is 100 percent effective and the turbine train is at 100 percent load (SCR and oxidation catalyst are not yet commissioned).

The applicant used the U.S. EPA approved AERMOD model for the calculation of commissioning impacts. **AIR QUALITY Table 15** shows the highest modeled impacts in comparison with the one-hour NO_2 and CO standards and the 8-hour CO standard. The modeled NOx and CO emission rates presented show that there is no reasonable expectation that the emissions from initial commissioning will cause or contribute to an exceedance of the limiting ambient air quality standards.

AIR QUALITY Table 15
CTG Commissioning Modeling
Maximum 1 hour Impacts (µg/m^3)

Pollutant	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
NO_2	109.8	174.8	284.6	338	84%
CO 1-HOUR	205.5	2645	2851	23,000	12%
CO 8-HOUR	166.0	944.4	1110.4	10,000	11%

Source: CPV 2007a

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5. There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the model to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, the emissions of NOx and VOC from the CPV Sentinel project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards.

Secondary PM10 formation, which is assumed to actually consist of 100 percent PM2.5 for this project assessment, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first, and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid does and converts completely to a particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out, however the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as "ammonia rich" and "ammonia poor." In the case of the "ammonia rich" condition, there is more than enough ammonia in the atmosphere to react with all the sulfuric acid and to establish a nitric acid-ammonium nitrate balance. Further ammonia emissions in this case will not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an “ammonia poor” environment, there is insufficient ammonia to establish a nitric acid-ammonium nitrate balance, and thus additional ammonia will tend to increase PM2.5 concentrations.

An extensive study of the area near Rubidoux in Riverside County, and other studies of ambient air quality in the South Coast Basin, indicates that the entire Basin is likely to be ammonia rich. The ammonia sources are primarily driven by ammonia emissions from livestock, soil (natural emissions and agricultural additives), motor vehicles and domestic emissions. These sources exist at various intensities across the basin, giving rise to the transport of ammonia (as ammonium, NH_4, which is more stable than ammonia, NH_3) throughout the basin. Since the ambient air concentrations are likely ammonia rich, further ammonia emissions from the CPV Sentinel project might not lead to further formation nitric and sulfuric acid, and ultimately conversion to ammonium nitrate or sulfate particulate. While there may be some conversion from the ammonia emitted from the project, the conversion rate might also well be zero. Furthermore, there is currently no regulatory model that can predict the conversion rate. Therefore, staff is not able to reasonably estimate what impacts, if any, there will be from the project’s ammonia emission.

Additionally, the actual ammonia emissions from the CPV Sentinel project will typically be approximately 10 to 50 percent of the ammonia limit being imposed (5 ppm at 15 percent O_2 averaged over one hour). The point at which the project begins to emit at greater than 50 percent of the limit is typically the indicator to the operator that the SCR catalyst material needs to be replaced. Once this major overhaul is completed the SCR performance is typically returned to near new levels (approximately 1 ppm or better). It is in the best interest of the project owner to perform these overhauls as required so that the cost of ammonia stays low for the project. Thus for the vast majority of the project life, the ammonia emissions are expected to be below 2 ppm. An emission of any type of pollutant at this level has a very low potential to cause a significant impact.

Staff finds that it is not reasonably possible to estimate the impacts from the CPV Sentinel project emissions of ammonia, but that these emissions are small and well controlled so that it is reasonable to assume that they are not likely to cause or contribute to an exceedance of the PM10 or PM2.5 ambient air quality standards or that at least it is reasonably speculative. Thus, staff concludes that the CPV Sentinel project ammonia emissions do not have the potential to cause a significant impact on the ambient air quality.

The emissions of NOx and SOx from the CPV Sentinel project do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region. These impacts would be significant because they would contribute to ongoing violations of the state and federal PM2.5 ambient air quality standards. The mitigation of the project NOx and SOx emissions is discussed in the Operations Mitigation section below.

Visibility Impacts

A visibility analysis of a project's gaseous emissions is required under the Federal Prevention of Significant Deterioration (PSD) permitting program if the project triggers the PSD thresholds and under District Rule 1303 if the specific wilderness areas are within a prescribed distance from the facility. The analysis provided by the applicant showed that the nearest Class 1 areas are San Jacinto Wilderness Area, Joshua Tree National Park and San Gorgonio Wilderness Area. The predicted visual contrast values for these three Class 1 areas are below the significance criterion for actual plume backgrounds and the project is thus considered to not have a significant impact on visibility for these areas.

Operations Mitigation

Applicant's Proposed Mitigation

The CPV Sentinel project's air pollutant emissions impacts will be reduced by using emission control equipment on the project and by providing emission offsets. To reduce NOx emissions, the applicant proposes to use water injection into the combustors in the CTGs and an SCR system with an ammonia injection grid.

Cooling Towers

To reduce the PM10 emissions from the cooling towers, the applicant has committed to using wet, mechanical draft cooling towers with a drift eliminator rated at 0.0005 percent and the cooling tower's water total dissolved solids will be limited to 5,000 mg/liter. The SCAQMD does not address cooling towers in its permits to construct or operate. Thus staff proposes that the cooling tower compliance be monitored through Conditions of Certification **AQ-SC10** and **AQ-SC11,** and that mitigation measures be implemented for avoiding chronic exceedences .

Combustion Turbine

To reduce CO emissions, the applicant proposes to use a combination of good combustion and maintenance practices, along with an oxidizing catalyst. The use of a clean-burning fuel (natural gas) and the efficient combustion process of the CTGs will limit VOC and PM10 emissions. The use of natural gas as the only fuel will limit SO_2 emissions.

Water Injection

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NOx formed during combustion. One method has been steam or water injected into the combustor cans to reduce combustion temperatures and the formation of thermal NOx, which is the primary source of NOx emissions from a CTG. This method has been employed for many years and is well understood and has been proposed for the GE LMS100 turbines for this project.

Flue Gas Controls

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed for the GE LMS100s. The applicant is proposing two catalyst systems, an SCR system to reduce NOx, and an oxidizing system to reduce CO and VOC.

Selective Catalytic Reduction (SCR)

SCR refers to a process that chemically reduces NOx by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen.

The process is termed selective because the ammonia reducing agent preferentially reacts with NOx rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950^{o} F to 1,100^{o}F.

Catalysts generally operate between 600 degrees to 750 degrees F (CARB 1992), and are normally placed inside the exhaust where the flue gas temperature has partially cooled. At temperatures lower than 600 degrees F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called “ammonia slip.” At temperatures above about 800 degrees F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770 degrees F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NOx to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

Oxidizing Catalyst

To reduce the turbine CO and VOC emissions, the applicant proposes to install an oxidizing catalyst, which is similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a noble metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO_2). The catalyst is proposed to limit the CO concentrations exiting the exhaust stack to six ppm, corrected to 15 percent excess oxygen and averaged over three-hours.

Emission Offsets

The applicant has secured sufficient offsets to satisfy SCAQMD Rule 1303 (which requires Emission Reduction Credits (ERCs)) and SCAQMD Regulation XX (which requires participation in the RECLAIM program), as well as to mitigate the project impacts under CEQA. **AIR QUALITY Table 16** summarizes the applicant’s proposals to offset or otherwise mitigate the CPV Sentinel project emission impacts.

AIR QUALITY Table 16
Operational Emission Offsets and Mitigation Proposed by the Applicant

Pollutant	Amount of Offsets Required	Offset or other mitigation
VOC	441 lbs/day[a]	ERCs – supplied by CPV Sentinel, LLC.
NOx	Commissioning Year RTCs – 286,786.05 lbs/year Other Years RTCs – 240,958.05 lbs/year	RTCs – supplied by CPV Sentinel, LLC.
SOx	Commissioning Year – 13,928 lbs/year Other Years – 13,560 lbs/year	AQMD's internal offset accounts, per AB1318.
PM10	Commissioning Year –118,120 lbs/year Other Years – 112,180 lbs/year	AQMD's internal offset accounts, per AB1318.
CO	None	.[b]
PM2.5	None	.[d]

a Includes 1.2-to-1.0 offset ratio, as per Rule 1303(b)(2)(A.)

b SSAB is not classified as Nonattainment for federal and state ambient air quality standards for CO. (SSAB is classified as Attainment for state and is Unclassified/Attainment for federal.) Therefore, no CO offsets are required. The worst case maximum yearly CO emission of 188 tons/year is below the 250 ton/year threshold for Prevention of Significant Deterioration (PSD) as specified by Rule 1701(b)(2). Therefore, does not require a PSD permit.

c Assuming all (100%) of PM10 emissions are PM2.5.

d SSAB is not classified as Nonattainment for federal and state ambient air quality standards for PM2.5. (SSAB is Unclassified for state and Unclassified/Attainment for federal.) Therefore, no PM2.5 offsets are required. The worst case maximum yearly PM2.5 emission of 59.06 tons/year is below the 250 ton/year threshold for PSD and, therefore, it does not require a PSD permit.

The Regional Clean Air Incentives Market (RECLAIM) is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications, reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reduction credits. The RECLAIM program established an initial allocation (beginning in 1994) and an ending allocation (to be attained by the year 2003) for each facility within the program (Rule 2002). Additional adjustments to the ending allocation were adopted in 2005. Under the program, each facility then reduces its allocation annually on a straight line from the initial to the ending allocation. The RECLAIM program supersedes other specified district rules, where there are conflicts. As a result, the RECLAIM program has its own rules for permitting, reporting, monitoring (including continuous emission monitoring (CEM)), record keeping, variances, breakdowns and the New Source Review program, which incorporates BACT requirements (Rules 2004, 2005, 2006 and 2012). RECLAIM also has its own banking rule, Rule 2007, for RECLAIM Trading Credits (RTCs). CPV Sentinel is exempt and excluded from the SOx RECLAIM program (Rule 2011) because it uses natural gas exclusively (per Rule 2001). However, it is subject to the rules of RECLAIM for NOx emissions.

AB 1318, which went into effect on January 1, 2010, requires the SCAQMD, upon making a specified finding, to transfer SOx and PM10 emission offsets from its internal offset accounts to eligible electric generating facilities. The specified findings required to be made in order to determine whether or not an electrical generating facility is eligible to receive emission offsets from the SCAQMD's internal offset account are as follows:

- "In order to be eligible for emission reduction credits pursuant to this section, an electrical generating facility shall meet all of the following requirements:" [Health & Safety Code Section 40440.14(d)]
    - 0 **"**Be subject to the permitting jurisdiction of the State Energy Resources Conservation And Development Commission." [Health & Safety Code Section 40440.14(D)(1)]
    - 0 "Have a purchase agreement, executed on or before December 31, 2008, to provide electricity to a public utility, as defined in section 216 of the Public Utilities Code, subject to regulation by the Public Utilities Commission, for use within the Los Angeles basin local reliability area." [Health & Safety Code Section 40440.14(d)(2)]
    - 0 "Be under the jurisdiction of the South Coast District, but not within the South Coast Air Basin.**"** [Health & Safety Code Section 40440.14(d)(3)]

The CPV Sentinel project meets all three of these requirements regarding Commission and SCAQMD jurisdiction, purchase agreements dated prior to December 31, 2008 and location outside of the South Coast air basin.

The SCAQMD's requirements for implementation of the emission offset credit transfer from its internal offset credit account and offset tracking system, as specified in AB1318, are as follows:

- "The executive officer of the south coast district, upon finding that the eligible electrical generating facility proposed for certification by the State Energy Resources Conservation and Development Commission meets the requirements of the applicable new source review rule and all other applicable district regulations that must be met under Section 1744.5 of Title 20 of the California Code of Regulations, shall credit to the south coast district's internal emission credit accounts and transfer from the south coast district's internal emission credit accounts to eligible electrical generating facilities emission credits in the full amounts needed to issue permits for eligible electrical generating facilities to meet requirements for sulfur oxides (SOx) and particulate matter (PM2.5 and PM10) emissions." [Health and Safety Code Section 40440.14(a)]
- In implementing this permitting action, "the south coast district shall rely on the offset tracking system used prior to the adoption of Rule 1315 of the south coast district until a new tracking system is approved by the United States Environmental Protection Agency and is in effect, at which point that new system shall be used by the south coast district." [Health & Safety Code Section 40440.14(b)(1)]
- "In addition to using the prior offset tracking system, the district shall also make use of any emission credits that have resulted from emission reductions and shutdowns from minor sources since 1990. The district shall make any necessary submissions to the United States Environmental Protection Agency with regard to the crediting

and use of emission reductions and shutdowns from minor sources." [Health & Safety Code Section 40440.14(b)(2)]

The SCAQMD has completed these requirements as documented in the addendum to their Final Determination of Compliance (SCAQMD, 2010).

In addition, the SCAQMD is required to report the emission offsets to the Energy Commission as follows:

- "Within 60 days of the effective date of this section, for each eligible electrical generating facility, the south coast district shall report to the State Energy Resources Conservation and Development Commission the emission credits to be credited and transferred pursuant to subdivision (a). The State Energy Resources Conservation and Development Commission shall determine whether the emission credits to be credited and transferred satisfy all applicable legal requirements. In the exercise of its regulatory responsibilities under its power facility and site certification authority, the State Energy Resources Conservation and Development Commission shall not certify an eligible electrical generation facility if it determines that the credit and transfer by the south coast district do not satisfy all applicable legal requirements." [Health & Safety Code Section 40440.14(c)]

The SCAQMD has reported the proposed emission offsets to the Energy Commission. These offsets have been determined by staff to satisfy all applicable legal requirements.

Finally, the transfer of offsets to an electrical generating facility is subject to the following:

- "The executive officer shall not transfer emission reduction credits to an electrical generating facility pursuant to this section until the receipt of payment of the mitigation fees set forth in the south coast district's Rule 1309.1, as adopted on August 3, 2007. The mitigation fees shall only be used for emission reduction purposes. The south coast district shall ensure that at least 30 percent of the fees are used for emission reductions in areas within close proximity to the electrical generating facility and at least 30 percent are used for emission reductions in areas designated as "Environmental Justice Areas" in Rule 1309.1." [Health & Safety Code Section 40440.14(e)]

For the purposes of the AB 1318 Tracking System, which consists of the EPA-approved tracking system in place prior to the passage of Rule 1315, the SCAQMD has identified a series of emission offsets for PM10 and SOx which have been created as a result of reductions from permitted equipment that permanently ceased operation in SCAQMD. These offsets all meet the integrity criteria for qualifying as offsets, meaning they are all Real, Permanent, Quantifiable, Enforceable and Surplus, as required by federal law. These offsets are all a result of emission reductions from permitted equipment that permanently ceased operation in the SCAQMD since 1990 and the SCAQMD has not issued any ERCs to the companies who operated the equipment as a result of the reductions. These PM10 and SOx offsets have been removed from the SCAQMD's internal offset accounts and have not been used by any other source permitted by SCAQMD.

The amounts of emission offsets are based on actual PM10 and SOx emissions reported to the SCAQMD under the SCAQMD's Annual Emissions Reporting Program. In addition, for each source of credit, the equipment has been shutdown and the permits have been inactivated by the SCAQMD. The emission reductions have occurred during the calendar years 2002 and 2008 for PM10 credits and during calendar years 2002 through 2006 for SOx credits.

AIR QUALITY Tables 17 and 18 below include a listing of the PM10 and SOx offsets, respectively, deposited in the AB 1318 Tracking System for use by electrical generating facilities eligible to use the offsets pursuant to AB 1318 requirements. These tables show PM10 and SOx offsets in the AB 1318 Tracking System available for use by eligible electric generating facilities. These offsets are available for transfer to any electrical generating facility which is eligible to obtain offsets from AQMD and upon receipt of payment of mitigation fees set forth in AQMD's Rule 1309.1, as adopted on August 3, 2007, pursuant to AB 1318.

The CPV Sentinel meets all of the above requirements of AB 1318 to qualify for obtaining emission offsets from the AQMD's internal offset account.

AIR QUALITY Table 17
PM10 Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
AAA Glass Corp	Los Angeles	Glass Melting Furnace	1,877.8
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	604.8
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	604.8
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	604.8
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	604.8
AES Huntington Beach, Llc	Huntington Beach	Turbine Engine - Natural Gas/Oil	1,417.2
AES Huntington Beach, Llc	Huntington Beach	Turbine Engine - Natural Gas/Oil	1,417.2
AES Huntington Beach, Llc	Huntington Beach	Turbine Engine - Natural Gas/Oil	1,417.2
Anaheim Marriott Hotel	Anaheim	Boiler - Natural Gas	20.4
Anaheim Marriott Hotel	Anaheim	Boiler - Natural Gas	20.4
Anaheim Marriott Hotel	Anaheim	Boiler - Natural Gas	19.3
Anaheim Marriott Hotel	Anaheim	Boiler - Natural Gas	19.3
Associated Ready Mixed Concrete Inc	Corona	Concrete Batch Equipment	27.4
Astechengineeredproductsinc.	Santa Ana	Abrasive Blasting - Open	16.0
Aurora Modular Industries	Moreno Valley	Open Spray Equipment	451.4

AIR QUALITY Table 17
PM10 Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
Aurora Modular Industries	Moreno Valley	Open Spray Equipment	451.4
Aurora Modular Industries	Moreno Valley	Open Spray Equipment	451.4
Aurora Modular Industries	Moreno Valley	Open Spray Equipment	451.4
Aurora Modular Industries	Moreno Valley	Open Spray Equipment	451.4
Blackhawk Furniture, Inc	Riverside	Spray Booth	604.0
Bocchi Laboratories Inc	Walnut	Boiler - Natural Gas	87.6
California Portland Cement Co	San Juan Capistrano	Cement Storage Silo	12.0
CBS Inc	Los Angeles	Boiler - Natural Gas/Oil	89.6
CBS Inc	Los Angeles	Boiler - Natural Gas/Oil	89.6
Century Rim Corp	Brea	Bakery Oven	32.1
Century Rim Corp	Brea	Spray Booth	5,272.0
Chandler Aggregates	Corona	Aggregate Production	1,411.2
Clean Steel Inc	Long Beach	Material Size Reduction	4,112.5
CMC Printed Bag Inc	Whittier	Afterburner	29.0
Color Master Printex, Inc	Vernon	Tenter Frame Oven	75.6
Color Master Printex, Inc	Vernon	Boiler - Natural Gas	75.6
Color Master Printex, Inc	Vernon	Boiler - Natural Gas	75.6
Colorgraphics	Los Angeles	Printing Press - Heat Set	5.0
Colorgraphics	Los Angeles	Printing Press - Heat Set	5.0
Colorgraphics	Los Angeles	Printing Press - Heat Set	5.0
Colorgraphics	Los Angeles	Afterburner	5.0
Commonwealth Aluminum Concast Inc	Torrance	Coating Equipment With Afterburner	671.7
Crest Graphics Inc	Commerce	Printing Press With Afterburner	48.7
Crest Graphics Inc	Commerce	Drying Oven With Afterburner	77.0
Diamond Pacific Products Co	Perris	Boiler - Natural Gas	92.8
Douglas Furniture Of California Llc	Redondo Beach	Boiler - Wood Fired With Baghouse	32.5
Dynamite Inc	Diamond Bar	Portable Diesel Ice	1,704.0
Dynamite Inc	Diamond Bar	Portable Diesel Ice	1,118.0
El Camino College	Torrance	Boiler - Natural Gas	192.0
Elsinore Ready-Mix Co Inc	Lake Elsinore	Aggregate Size Reduction	13.7
Equitable Real Est/Compass Mgmt Leasing	Irvine	Boiler - Natural Gas	4.9
Falcon Foam, A Div Of Atlas Roofing Corp	Los Angeles	Boiler - Natural Gas	293.1
Falcon Foam, A Div Of Atlas Roofing	Los Angeles	Afterburner	230.2

AIR QUALITY Table 17
PM10 Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
Corp			
Ford Auto Body Inc	San Fernando	Spray Booth	6.0
FS Precision Tech Llc	Compton	Abrasive Blasting Cabinet	77.2
FS Precision Tech Llc	Compton	Abrasive Blasting Cabinet	30.3
FS Precision Tech Llc	Compton	Abrasive Blasting Cabinet	30.3
FS Precision Tech Llc	Compton	Abrasive Blasting Cabinet	30.3
Great American Picture Frame Co	Los Angeles	Open Spray Equipment	104.5
Great American Picture Frame Co	Los Angeles	Spray Booth	104.5
Great American Picture Frame Co	Los Angeles	Open Spray Equipment	104.5
Holga Inc	Van Nuys	Paint Burnoff Furnace	18.6
Honeywell International Inc	Torrance	Jet Engine Test Equipment	59.0
Intermetro Industries Corp	Rancho Cucamonga	Heat Treating Furnace	65.0
Intermetro Industries Corp	Rancho Cucamonga	Nickel Plating Tank	17.0
Intermetro Industries Corp	Rancho Cucamonga	Boiler - Natural Gas	87.5
Interstate Brands Corp/Dicarlo	San Pedro	Bakery Oven	131.2
Interstate Brands Corp/Dicarlo	San Pedro	Bakery Oven	133.5
Interstate Brands Corp/Dicarlo	San Pedro	Bakery Oven	93.0
Interstate Brands Corp/Dicarlo	San Pedro	Boiler - Natural Gas	109.0
KMCWheel Co Inc	Riverside	Aluminum Furnace	2,940.8
Kraco Enterprises Inc	Compton	Boiler - Oil	429.5
Kraft Foods North America/Nabisco Div	Buena Park	Bakery Oven	110.1
Kraft Foods North America/Nabisco Div	Buena Park	Bakery Oven	110.1
Kraft Foods North America/Nabisco Div	Buena Park	Bakery Oven	110.1
Lithographix Inc	Los Angeles	Afterburner	15.0
Little Company Of Mary Hospital	Torrance	Boiler - Natural Gas/Oil	404.7
Long Beach Aquarium Of The Pacific	Long Beach	Heater/Furnace - Natural Gas	301.3
Matthews International Corp	Romoland	Foundry Sand Storage With Baghouse	9,460.5
Mountainview Generating Station	Redlands	Utility Boiler - Natural Gas/Oil	3,365.5
Mountainview Generating Station	Redlands	Utility Boiler - Natural Gas/Oil	3,365.5
Neville Chem Co	Anaheim	Chemical Storage Tank	268.4
Neville Chem Co	Anaheim	Boiler - Natural Gas	239.7
Oldcastle Westile, Inc.	Corona	Cement Slurry System	2,111.0

AIR QUALITY Table 17
PM10 Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
One Wilshire, Carlyle One Wilshire, Llc	Los Angeles	Boiler - Natural Gas	19.1
Ontario Sandblasting Co	Ontario	Abrasive Blasting Cabinet	12.8
Ontario Sandblasting Co	Ontario	Abrasive Blasting Cabinet With Baghouse	12.8
Ontario Sandblasting Co	Ontario	Abrasive Blasting Cabinet With Baghouse	12.8
Ortiz Enterprises Inc	Various Locations	Aggregate Crushing System	1,233.0
Pacific Sun Casual Furn Div Of Pac Outdo	Hemet	Powder Coating Spray Booth	30.0
Paradise Textile Co	Chino	Heater/Furnace - Natural Gas	1,109.5
Plasti Personalities Inc	Harbor City	Boiler - Natural Gas	9.4
Polyclad Laminates Inc	Santa Ana	Boiler - Natural Gas	291.6
Polyclad Laminates Inc	Santa Ana	Boiler - Natural Gas	291.6
Pratt & Whitney Rocketdyne, Inc.	Canoga Park	Boiler - Natural Gas	30.5
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	1,959.1
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	1,959.1
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	1,959.1
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	1,959.1
Reliant Energy Etiwanda, Inc.	Etiwanda	Utility Boiler - Natural Gas/Oil	33,079.3
Reliant Energy Etiwanda, Inc.	Etiwanda	Utility Boiler - Natural Gas/Oil	33,079.3
Scheu Manufacturing Company	Rancho Cucamonga	Curing Oven	13.0
Shawcor Pipe Protection Llc.	Fontana	Abrasive Blasting - Open	7,677.0
Smurfit-Stone Container Enterprises	Santa Fe Springs	Boiler - Natural Gas/Lpg	237.0
Statewide Sandblasting	Various Locations	Abrasive Blasting - Open	2,313.0
Sunlaw Cogeneration Partners I	Vernon	Turbine Engine - Natural Gas	1,295.4
Sunlaw Cogeneration Partners I	Vernon	Turbine Engine - Natural Gas	2,467.4
TABC, Inc	Long Beach	Curing Oven	121.5
Telair International	Rancho Dominguez	Spray Booth	69.5
The Boeing Company	Seal Beach	Emergency Ice - Diesel Fire Pump	868.0
Trend Offset Printing Services, Inc	Los Alamitos	Afterburner	42.0
Universal Die Casting Co	Vernon	Brass Crucible	370.5
Us Postal Service, Santa Clarita Center	Santa Clarita	Heater/Furnace - Natural Gas	66.0
Valmont Coatings, Calwest Galv	Long Beach	Portable Diesel Ice	2.7

AIR QUALITY Table 17
PM10 Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
Vought Aircraft Industries	Hawthorne	Boiler - Natural Gas	51.0
Webb-Massey Co Inc	Orange	Spray Booth	572.7
Webb-Massey Co Inc	Orange	Spray Booth	572.7
Whitewater Rock & Supply Co	White Water	Rock Crushing System	1,460.0
Wings West Inc	Santa Ana	Spray Booth	498.0
Wings West Inc	Santa Ana	Spray Booth	498.0
Wings West Inc	Santa Ana	Spray Booth	498.0
Woodard, Llc.	Ontario	Powder Coating Oven	10.2
Woodard, Llc.	Ontario	Drying Oven	5.1
Total			**148,582.7**

AIR QUALITY Table 18
SOx Reductions from Sources Which Ceased Operation

Company Name	Location	Equipment Description	Emission Credits (lb/year)
AAA Glass Corp	Los Angeles	Glass Melting Furnace	6,295.4
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	108.0
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	108.0
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	108.0
AES Alamitos, Llc	Long Beach	Turbine Engine - Natural Gas/Oil	108.0
CBS Inc	Los Angeles	Boiler - Natural Gas/Oil	7.1
CBS Inc	Los Angeles	Boiler - Natural Gas/Oil	7.1
Century Rim Corp	Brea	Bakery Oven	3.5
Color America Textile Processing Inc	Los Angeles	Carpet Processing Sys With Esp	3.3
El Camino College	Torrance	Boiler - Natural Gas	15.2
Gateway Sandblasting	Various Locations	Open Abrasive Blasting	455.2
Holga Inc	Van Nuys	Paint Burnoff Furnace	2.0
Honeywell International Inc	Torrance	Jet Engine Test Equipment	4.5
Mountainview Generating Station	Redlands	Utility Boiler - Natural Gas/Oil	265.5
Mountainview Generating Station	Redlands	Utility Boiler - Natural Gas/Oil	265.5
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	169.6
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	169.6
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	169.6

AIR QUALITY Table 18 SOx Reductions from Sources Which Ceased Operation			
Company Name	**Location**	**Equipment Description**	**Emission Credits (lb/year)**
Reliant Energy Etiwanda, Inc.	Etiwanda	Turbine Engine - Natural Gas/Oil	169.6
Reliant Energy Etiwanda, Inc.	Etiwanda	Utility Boiler - Natural Gas/Oil	2,611.3
Reliant Energy Etiwanda, Inc.	Etiwanda	Utility Boiler - Natural Gas/Oil	2,611.3
Sunlaw Cogeneration Partners I	Vernon	Turbine Engine - Natural Gas	2,506.4
Sunlaw Cogeneration Partners I	Vernon	Turbine Engine - Natural Gas	2,193.5
The Boeing Company	Seal Beach	Emergency Ice -Diesel Fire Pump	183.5
		Total	**18,540.6**

Adequacy of Proposed Mitigation

Potential Mitigation for VOC, SOx, PM10 and PM2.5

VOC Emissions and Offsets

The CPV Sentinel project will comply with all of the SCAQMD's VOC offset requirements (at a 1.2-to-1.0 offset ratio) by providing VOC ERCs prior to issuance of the Permit to Construct (PTC), as specified in Rule 1303(b)(2). As shown in **AIR QUALITY Table 19** below, CPV Sentinel has already purchased adequate amounts of VOC ERCs to offset 412 lbs/day of VOC emissions and will provide an additional 29 lbs/day of VOC ERCs prior to issuance of the final Title V permit to cover the maximum offset liability of 441 lbs/day of VOC emissions.

AIR QUALITY Table 19
VOC Emission Offsets and Mitigation Proposed by the Applicant

ERC Certificate No.	ERC Certificate Registered Owner	ERC Certificate Amount (lbs/day)
AQ007877	Tenasko	348
AQ007879	Tenasko	64
	Total Amounts of VOC ERCs Provided	412
	Additional VOC ERCs to be Provided	29
	Total Emissions & VOC ERCs	441

NOx Emissions and Offsets

The CPV Sentinel project complies with all of the NOx offset requirements (at a 1.0-to-1.0 offset ratio) by holding sufficient NOx RTCs to offset the annual emission increase for the first year of operation prior to commencement of initial operation, as specified in Rule 2005(b)(2). The SCAQMD provides a programmatic demonstration, as approved by EPA, in March of each year in its Annual RECLAIM Audit report to the Governing Board that the 1.2 to 1 offset ratio required by federal law is met on an aggregate basis for RECLAIM new and modified sources. CPV Sentinel shall also, at the commencement of each subsequent compliance year, hold NOx RTCs equal to the amount required by permit conditions, as specified in Rule 2005(f)(1).

PM10 and SOx Emissions and Offsets

Emission Offsets - The SSAB is in attainment with both federal and state SO_2 and Sulfate ambient air quality standards, as applicable. However, SO_2 is also considered a precursor to PM10. Presently the SSAB is still designated as “Nonattainment” with both federal and state PM10 ambient air quality standards.

CPV Sentinel is obtaining offsets for both PM10 and SOx from the SCAQMD’s internal bank pursuant to AB 1318. Under federal law, any required PM10 and SOx offsets have to be provided at an offset ratio of 1.0-to-1.0. In addition, California state law, if applicable to any project, requires actual (not maximum potential) emissions to be offset at the same 1.0-to-1.0 offset ratio. Therefore, the maximum amount of offsets that are being provided for the CPV Sentinel project’s emissions in the initial commissioning year are 118,120 lbs/year and 13,928 lbs/year of PM10 and SOx, respectively, as shown earlier in **AIR QUALITY Table 16**. CVP Sentinel has purchased these offsets from the SCAQMD’s internal emission credit accounts pursuant to AB 1318.

Redesignation & Maintenance Plan – Although CPV Sentinel is obtaining and the SCAQMD is providing emission offsets for PM10 and SOx (as precursor to PM10), the AQMD and CARB Governing Boards have already approved the SSAB PM10 Redesignation and Maintenance Plan (RMP) for submittal to EPA for inclusion into the SIP. Under federal NSR, offsets are required prior to start of operation. However, should EPA approve this RMP and redesignate the SSAB as attainment with federal PM10 NAAQS, this project will not be subject to the Nonattainment federal NSR requirements and will not be required to provide any PM10 or SOx offsets to meet federal requirements.

In addition, the CPV Sentinel project’s maximum worst case year (i.e. the initial commissioning year) PM10 emissions are 118,120 lbs/year (or 59.06 tons/year). The federal Major Source threshold for PM10 offsets is 70 tons/year, below which no offsets are required under federal NSR regulations. Although the CPV Sentinel project’s maximum potential to emit PM10 emissions are below the federal Major Source threshold for offsets, CPV Sentinel is obtaining offsets for both PM10 and SOx from the SCAQMD internal bank pursuant to AB 1318.

PM2.5 Emissions and Offsets

The CPV Sentinel project complies with the PM2.5 offset requirements on the basis that the SSAB is not classified as “Nonattainment” for federal and state ambient air quality standards for PM2.5. (SSAB is Unclassified for state and Unclassified/Attainment for federal.) Therefore, offsets are not specifically required for PM2.5 to demonstrate compliance with the Clean Air Act. Also the maximum worst case yearly PM2.5 emissions, even assuming that all (100%) of the PM10 emissions are PM2.5, is 59.06 tons/year. CPV Sentinel PM2.5 emissions will be offset through the purchase of PM10 offsets from the SCAQMD internal bank pursuant to AB 1318, since a majority of the offsets would occur from combustion sources where PM10 emissions are generally PM2.5 or smaller. Therefore, all project-related PM2.5 emissions will be offset.

Potential Mitigation for CO

The CPV Sentinel project complies with the CO offset requirements on the basis that the SSAB is not classified as “Nonattainment” for federal and state ambient air quality standards for CO. (SSAB is classified as Attainment for state and Unclassified/ Attainment for federal.) Therefore, offsets are not required. Also, the maximum worst case yearly CO emission is 188 tons/year, which is below the PSD threshold of 250 tons/year.

As discussed in the Operation and Impacts section, staff believes that the project’s potential impacts on the CO ambient air quality standards are not significant. Thus, staff does not recommend any further CO mitigation measures.

Quantification of Mitigation

Staff uses the 30-day average daily emission value for characterizing the project emission profile in the South Coast air basin for the purpose of quantifying offset requirements. The 30-day average is different from the estimated worst case daily emissions (**AIR QUALITY Table 10**). For the 30-day average, the SCAQMD sums the facility emissions for the worst case month, then divides that sum by 30 (or 31 depending on the month) to obtain a 30-day average daily emissions (in units of lbs/day). This calculation methodology does result in a lower value than is presented in **AIR QUALITY Table 10**, but it is the method by which the SCAQMD determines the required amount of offsets for each pollutant.

The ERCs (the offsets) are calculated by the SCAQMD by taking the total emissions for the year and dividing that number by 365 to create the lbs/day annual average. An annual average calculated in this method is always going to be lower than a 30-day average used by the SCAQMD from the same emitting source, since the 30-day average will capture periods when a project, such as a peaker power plant, is operated at a higher load than the annual average. Any emitting source will always have a month in which it operates more than any other month, but in an annual average this peak month is washed out over the year. Thus the lbs/day ERC calculation is more conservative than the 30-day average lbs/day project emission calculation. Therefore, for projects located in the South Coast air basin, staff uses the 30-day average lbs/day value to characterize the project emission profile when comparing it to the ERCs being offered.

The project emissions shown in **AIR QUALITY Table 20** are calculated by the 30-day average lbs/day values shown (with the exception of NOx which is pounds per year). Staff concludes that the credits are adequate to offset the project emissions.

AIR QUALITY Table 20
CEQA Mitigation (30-day average)

	NOx	VOC	SOx	PM10
	(lbs/year)	(lbs/day)		
Total Project Emissions[3]	286,787[1] 240,959[2]	368	78	647
Emission Reduction Credits or RECLAIM Trading Credits	286,787[1] 240,959[2]	441	78	647
Total Credits	286,787[1] 240,959[2]	441	78	647

1 First year of operation includes commissioning emission estimates and operational assumptions made in AIR QUALITY Table 11.

2 Second year (and thereafter) of operation includes the assumptions made in AIR QUALITY Table 11.

3 Total project emissions include only the emissions from non-exempted equipment. In this case it includes only the operation of the eight combustion turbines.

Staff Proposed Mitigation

Staff recommends no further mitigation at this time.

CUMULATIVE IMPACTS AND MITIGATION

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts." (CEQA Guidelines, § 15355.) A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts." (CEQA Guidelines, § 15130(a)(1).) Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This analysis is primarily concerned with "criteria" air pollutants. Such pollutants have impacts that are usually (though not always) cumulative in nature. Rarely will a project by itself cause a violation of a federal or state criteria pollutant standard. However, a new source of pollution may contribute to violations of criteria pollutant standards because of the existing background sources or foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for air pollutant emission "offsets" and the use of "Best Available Control Technology" for new sources of emissions, and restrictions of emissions from existing sources of air pollution.

Much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" section describes the air quality background in the South Coast Air Basin, including a discussion of historic ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" section discusses the project's contribution to the local existing background caused by project construction. This following section includes three additional analyses:

- a summary of projections for ambient criteria pollutant levels by the air district and of the air district's programmatic efforts to abate such pollution levels;
- an analysis of the project's "localized cumulative impacts"; combining the project's direct emissions with the emissions of other local major emission sources; and
- a discussion of the impacts of chemically reactive pollutants: ozone and PM2.5.

Summary of Projections

The SCAQMD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone and particulate matter. The SCAQMD has summarized the cumulative impact of ozone and particulate matter on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the SCAQMD proposes to reduce impacts to air quality and public health, are summarized in four publicly available documents that the SCAQMD has adopted or will soon adopt. These adopted air quality plans are summarized below.

- **2007 Air Quality Management Plan** (adopted 6/1/2007)
  Link: www.aqmd.gov/aqmp/07AQMP/07AQMP.html

- **Final 2003 Air Quality Management Plan** (adopted 12/10/1999)
  Link: www.aqmd.gov/aqmp/AQMD03AQMP.htm

- **Final Socioeconomic Report for the Final 2003 AQMP** (adopted 8/1/2003)
  Link: www.aqmd.gov/aqmp/docs/2003AQMPSocio.pdf

- **Final 2003 Coachella Valley PM10 State Implementation Plan** (adopted 8/1/2002)
  Link: www.aqmd.gov/aqmp/docs/f2003CVsip.pdf

2007 Air Quality Management Plan

(*The following paragraphs are excerpts from the Executive Summary of the 2007 Air Quality Management Plan adopted by the SCAQMD June 1, 2007*)

The SCAQMD adopted (June 1, 2007) the 2007 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires an 8-hour ozone non-attainment area to prepare a State Implementation Plan (SIP) revision by June of 2007 (which has been completed) and a PM2.5 non-attainment area to submit a SIP revision by late 2007 (which has been completed). The SCAQMD has decided that it is most prudent to prepare a single comprehensive and integrated SIP revision that satisfies both the ozone and PM2.5 requirements. Additionally, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions and approved motor vehicle emission model. The AQMP is based on assumptions provided by both the California Air Resources Board (CARB) and the Southern California Association of Governments (SCAG) reflecting their upcoming model (EMFAC) for motor vehicle emissions and demographic updates.

The AQMP relies on a comprehensive and integrated control approach to achieve the PM2.5 standard by 2015 through implementation of short-term and midterm control measures and achieve the 8-hour ozone standard by 2021/2024 based on implementation of additional long-term measures. In order to demonstrate attainment by the prescribed deadlines, emission reductions needed for attainment must be in place by 2014 and 2020/2023 timeframe.

Since PM2.5 in the Basin is overwhelmingly formed secondarily, the overall draft control strategy focuses on reducing precursor emission of SOx, directly-emitted PM2.5, NOx, and VOC instead of fugitive dust. Based on the District's modeling sensitivity analysis, SOx reductions, followed by directly-emitted PM2.5 and NOx reductions, provide the greatest benefits in terms of reducing the ambient PM2.5 concentrations. While VOC reductions are less critical to overall reductions in PM2.5 air quality, they are heavily relied upon for meeting the 8-hour ozone standard. SOx is also the only pollutant that is projected to grow in the future, due to ship emissions at the ports, requiring significant controls.

Directly-emitted PM2.5 emission reductions from ongoing diesel toxic reduction programs and from the short-term and mid-term control measures are also incorporated into the AQMP. NOx reductions primarily based on mobile source control strategies (e.g., add-on control devices, alternative fuels, fleet modernization, repowers, retrofits) are also relied upon for attainment. Adequate VOC controls need to be in place in time for achieving significant VOC reductions needed for the 8-hour ozone standard by 2021/2024. Reducing VOC emissions in early years would also ensure continued progress in reducing the ambient ozone concentrations. The 8-hour ozone control strategy relies on the implementation of the PM2.5 control strategy augmented with additional long-term VOC and NOx reductions for meeting the standard by 2020/2023 timeframe. With respect to PM10, since the Basin did not attain the annual standard by 2006, additional local programs are proposed to address the attainment issue in an expeditious manner.

The AQMP control measures consist of three components: 1) the District's Stationary and Mobile Source Control Measures; 2) State and Federal Control Measures recommended by CARB and/or SCAQMD staff; and 3) Regional Transportation Strategy and Control Measures provided by SCAG.

The SCAQMD control strategy for stationary and mobile sources is based on the following approaches: 1) facility modernization; 2) energy efficiency and conservation; 3) good management practices; 4) market incentives/compliance flexibility; 5) area source programs; 6) emission growth management; and 7) mobile source programs. The AQMP also includes SCAQMD staff's recommended State and federal stationary and mobile source control measures since ARB has only developed an overview of a possible control strategy for PM2.5.

AIR QUALITY Table 21
Regulatory Agency Attainment Responsibilities and Jurisdiction

Agency	Jurisdiction
SCAG	AQMP conformity assessment. Regional Transportation Improvement Program. Transportation Control Measures.
Local Government/CTCs	Transportation and local government actions (i.e., land use approvals & ports). Transportation facilities.

These strategies are based on facility modernization, energy conservation measures and more stringent requirements for existing equipment (e.g., space heaters, ovens, dryers, furnaces). In addition to short-term and mid-term control measures, the SCAQMD is also committing to long-term VOC reductions of 32 tons per day by 2020 for the 8-hour ozone attainment.

Clean air for this region requires CARB to aggressively pursue reductions and strategies for on-road and off-road mobile sources and consumer products. In addition, considering the significant contribution of federal sources such as marine vessels, locomotives, and aircraft in the Basin (i.e., 72 percent of SOx and 34 percent of NOx), it is imperative that the U.S. EPA pursue and develop regulations for new and existing federal sources to ensure that these sources contribute their fair share of reductions toward attainment of the federal standards. Unfortunately, regulation of these emission sources has not kept pace with other source categories and as a result, these sources are projected to represent a significant and growing portion of emissions in the Basin. Without a collaborative and serious effort among all agencies, attainment of the federal standards would be seriously jeopardized.

Final 2003 Air Quality Management Plan

(*The following are excerpts from the 2003 Air Quality Management Plan adopted by the SCAQMD December 10, 1999*)

The SCAQMD amended the 1997 Air Quality Management Plan (AQMP) in 1999 to address the U.S. EPA's proposed disapproval of the 1997 Ozone SIP revision to ensure that the 1997 AQMP complied with or exceeded federal requirements. The 1999 AQMP amendments to the 1997 AQMP were subsequently approved by the U.S. EPA into the SIP in April 2000. The SCAQMD updated the PM10 portion of the 1997 AQMP for both the South Coast Air Basin and Coachella Valley in 2002 as part of the District's request to extend the PM10 attainment date from 2001 to 2006 for these areas as allowed under the federal Clean Air Act (CAA). The U.S. EPA approved the 2002 update on April 18, 2003.

The purpose of the 2003 Revision to the Air Quality Management Plan for the South Coast Air Basin (Basin) and those portions of the Salton Sea Air Basin under SCAQMD jurisdiction are to set forth a comprehensive program that will lead these areas into compliance with all federal and state air quality planning requirements. Specifically, the

2003 AQMP Revision is designed to satisfy the California Clean Air Act (CCAA) tri-annual update requirements and fulfill the District's commitment to update transportation emission budgets based on the latest approved motor vehicle emissions model and planning assumptions. The Plan will be submitted to U.S. EPA as a SIP revision once it is approved by the SCAQMD Governing Board and the California Air Resources Board (CARB).

The 2003 AQMP sets forth programs which require the cooperation of all levels of government: local, regional, state, and federal. Each level is represented in the Plan by the appropriate agency or jurisdiction that has the authority over specific emissions sources. Accordingly, each agency or jurisdiction is associated with specific planning and implementation responsibilities.

At the federal level, the U.S. EPA is charged with regulation of 49-state on-road motor vehicle standards; trains, airplanes, and ships; and non-road engines less than 175 horsepower. The CARB, representing the state level, also oversees on-road vehicle emission standards, fuel specifications, some off-road sources and consumer product standards. At the regional level, the SCAQMD is responsible for stationary sources and some mobile sources. In addition, the SCAQMD has lead responsibility for the development and adoption of the Plan. Lastly, at the local level, Associations of Governments have a dual role of leader and coordinator. In their leadership role, they, in cooperation with local jurisdictions and sub-regional associations, develop strategies for these jurisdictions to implement; as a coordinator, they facilitate the implementation of these strategies. For the South Coast Air Basin, the Southern California Association of Governments is the District's major partner in the preparation of the AQMP. Interagency commitment and cooperation are the keys to success of the AQMP.

Since air pollution physically transcends city and county boundaries, it is a regional problem. No one agency can design or implement the Plan alone and the strategies in the Plan reflect this fact.

Past air quality programs have been effective in improving the Basin's air quality.

Ozone levels have been reduced by half over the past 30 years, nitrogen dioxide, sulfur dioxide, and lead standards have been met, and other criteria pollutant concentrations have significantly declined. The federal and state CO standards were also met as of the end of 2002. However, the Basin still experiences exceedances of health-based standards for ozone and particulate matter less than ten microns in size (PM10).

Progress in implementing the 1997/1999 SIPs can be measured by the number of control measures that have been adopted as rules and the resulting tons of pollutants targeted for reduction. Emission reduction commitments and reductions achieved in 2010 are based on the emissions inventory from the 1997 SIP. Since October 1999, sixteen control measures or rules have been adopted or amended by the SCAQMD through October 2002. The primary focus of the District's efforts had been the adoption and implementation of VOC control measures. The SCAQMD has achieved 158 tons per day VOC reductions, exceeding its 1997/1999 SIP commitment by approximately 44.5 tons per day.

To date, ARB has committed to VOC and NOx emission reductions of approximately 90 and 106 tons per day, respectively, and has achieved 67 and 140 tons per day, respectively. While exceeding its NOx target by 34 tons per day, ARB fell short of the VOC target by 21 tons per day using the 1997 SIP currency. U.S. EPA was obligated to VOC and NOx emission reductions of approximately 35 and 75 tons per day, respectively, and has achieved 38 and 63 tons per day, respectively.

Final Socioeconomic Report for the Final 2003 AQMP

(*The following are excerpts from the Final Socioeconomic Report for the Final 2003 AQMP adopted by the SCAQMD August, 2003*)

The Final Socioeconomic Report accompanies the Final 2003 AQMP and presents the potential socioeconomic impacts resulting from implementation of this Plan. The Plan contains several short- and long-term strategies designed to achieve state and federal ambient air quality standards, and air quality planning requirements. These strategies will be implemented by the SCAQMD, the California Air Resources Board (ARB), the U.S. Environmental Protection Agency (U.S. EPA), and other local and regional governments. Implementation of these control strategies will affect the region's economy.

In recent years, there have been significant improvements in air quality in the Basin. Additional control is still needed in order to bring the Basin into compliance with the federal air quality standards. The benefits of better air quality through implementation of the draft final 2003 AQMP include increases in crop yields, visibility improvements, and a reduction in morbidity, higher survival rates, reduced expenditures on refurbishing building surfaces, and reduced traffic congestion. The total benefits of the draft final Plan are expected to exceed $6.6 billion since not all of the benefits associated with the implementation of the Plan can be quantified.

The projected annual implementation cost of the draft final Plan is $3.2 billion annually, on average. The cost estimate is divided into quantifiable and unquantifiable measures. The projected cost for 31 quantifiable short-term measures and some long-term measures is approximately $1.6 billion. Transportation control measures alone contribute to 57 percent of the total quantifiable cost. The cost of unquantifiable measures is projected to be approximately $1.6 billion. The cost of unquantified measures was derived from emission reductions in 2010 and the average cost effectiveness of quantifiable measures.

Without the AQMP, jobs in the four-county area are projected to grow at an annual rate of about 1.069 percent between 2002 and 2020. Cleaner air would result in 41,934 jobs created annually, on average. This would bring the job growth rate to an annual rate of 1.1 percent. On the other hand, the quantified measures are projected to result in 9,893 jobs forgone annually, on average, which would slow down the job growth rate to 1.054 percent relative to the baseline employment. The four-county region is projected to have

11 million jobs in 2020. The jobs created from clean air benefits would amount to 0.57 percent of the 2020 baseline jobs. The jobs forgone from quantified measures would be 0.2 percent of the 2020 baseline jobs.

All the 19 sub-regions are projected to have additional jobs created from cleaner air. All the ethnic groups are expected to have job gains as a result. The share of whites and Hispanics in job gains is projected to be 84 percent with other ethnic groups representing the balance. Implementation of quantified control measures would also result in additional jobs to be created between 2002 and 2006 of which whites are projected to have a 54 percent share and Hispanics would have a 32 percent share. In later years (2007 to 2020), these measures would result in an average of 19,761 jobs forgone annually of which the share of Hispanics is 25 percent.

Implementation of the final 2003 AQMP is projected to result in air quality improvements sufficient to attain the air quality standards by 2010 throughout the Basin. The air quality modeling results have, however, shown the greatest relative improvements and air quality benefit in the eastern portion of the Basin. The Chino-Redlands area is shown to have the greatest share of the monetary value of these improvements. A demographic analysis of the 2000 census showed that 45 percent of the population there is Hispanic and 36 percent white. The minority population increased from 45 percent in the 1990 census to 64 percent in the 2000 census.

The attainment of the air quality standards in 2010 depends on a full implementation of control measures, as proposed in the final 2003 AQMP. The costs of these measures will spread throughout various communities. The cost of quantified control measures that represent 30 percent of the total emission reductions towards clean air would exert a relatively higher share on the southern portion of Los Angeles County and the Chino-Redlands area than the rest of the communities.

The socioeconomic report examines industrial competitiveness in three areas: the Basin's share of national jobs, product prices and profits, and exports and imports. The quantified measures and benefits of the draft final 2003 AQMP are not expected to result in discernible differences in the four-county region’s share of national jobs. For the majority of sectors, the impact on product prices is projected to be less than one-half of one percent of the baseline index of product prices and the impact on profits is

projected to be less than one-half of one percent of the baseline index of profits. The impact on imports and exports is small as well, especially when the size of the four-county region is considered.

Final 2003 Coachella Valley PM10 State Implementation Plan

(*The following are excerpts from the Final 2003 Coachella Valley PM10 State Implementation Plan adopted by the SCAQMD August 1, 2003*)

The Coachella Valley PM10 non-attainment area consists of an approximately 2,500 square mile portion of central Riverside County. Geographically, the Valley is bounded by the San Jacinto Mountains to the west, and the Little San Bernardino Mountains to the east. Elevation ranges from approximately 500 feet above sea level in the northern part of the Valley to about 150 feet below sea level near the Salton Sea.

The Coachella Valley is currently designated as a serious non-attainment area for PM10. The SCAQMD is the air agency responsible for air quality planning and regulations in the Coachella Valley. Since it was designated as a PM10 non-attainment area, Coachella Valley governments, agencies, private and public stakeholders, along with the SCAQMD, have worked to reduce levels of PM10 dust. The 1996 Coachella Valley Plan dust control efforts were so successful that Coachella Valley became the first serious non-attainment area in the nation to request re-designation. The local dust control ordinances and SCAQMD's fugitive dust rules 403 and 403.1 were SIP-approved by U.S. EPA on January 8, 1999. The SCAQMD has invoked the U.S. EPA's Natural Events Policy (NEP) to identify high PM10 days that resulted from high-wind natural events. These days are not used in determining the 24-hour or annual average PM10 levels. Based on monitoring data and the NEP, the Coachella Valley demonstrated attainment of the annual average PM10 NAAQS (expected annual average mean for past three years) for each year from 1995 through 1999. It has demonstrated attainment of the 24-hour PM10 NAAQS from 1993 through 2002.

In 1999, annual average PM10 levels jumped up to 52.7 $\mu g/m^3$, significantly above levels seen in previous years (PM10 levels all reflect removal of natural events, if any). An improving economy had resulted in greater development, particularly of large resorts and recreational areas, and the area had suffered a number of dry years. After a series of SCAQMD enforcement actions at these large developments, the SCAQMD began a program of greater enforcement and outreach to developers and builders, and local government dust plan review and enforcement staff.

In response to this situation, the 2002 Coachella Valley State Implementation Plan (CVSIP) was developed, including a Most Stringent Measures analysis and additional control measures. It was adopted by the SCAQMD Governing Board on June 21, 2002. It was adopted by Coachella Valley Association of Government's (CVAG) Executive Committee on June 25, 2002. After comments by U.S. EPA, the SCAQMD Governing Board adopted the 2002 CVSIP Addendum on September 12, 2002, which detailed the 2003 milestone year target and emission budgets.

Since adoption of the 1990 CVSIP, the local Coachella Valley jurisdictions, CVAG, and the SCAQMD have worked closely to implement the various 1990 CVSIP control measures. This team approach has resulted in what was the most comprehensive dust control program in the nation at that time. The 1996 CVSIP describes the implementation status of these control measures in detail. In the 1994 CVSIP, additional BACM measures were identified. However, by 1996, the Coachella Valley had achieved the PM10 NAAQS and the SCAQMD requested its re-designation to attainment. At that time, the 1994 CVSIP BACM measures were incorporated as contingency measures in the 1996 CV Plan. In response to elevated PM10 levels from 1999 through 2001, the SCAQMD prepared and adopted the 2002 CVSIP, which included a most stringent measures analysis and enhanced control strategy. The 2002 CVSIP demonstrated attainment of the federal PM10 standards by 2006. The 2002 CVSIP described the previous dust control measures, including the original local dust control ordinances and SCAQMD Rules 403 and 403.1, all of which were adopted in 1992 and 1993 and have been SIP-approved by U.S. EPA, and the Clean Streets Management Program.

The 2002 CVSIP summarizes the dust control efforts that arose in response to significant dust control problems and nuisance situations at large construction sites in Spring 1999 and the rise in local PM10 levels above the annual average standard from 1999 through 2001. These programs, which are described in the 2002 CVSIP and summarized below, are continuing, including the expedited implementation of CMAQ-funded PM10 control projects, CVAG and SCAQMD sponsored Compliance Promotion Classes, “dust czars” for each jurisdiction, and a full-time SCAQMD inspector to coordinate SCAQMD and local enforcement activities.

In May 2001, SCAQMD assigned a full-time inspector to the Coachella Valley to improve outreach and compliance with existing dust control regulations. This was in addition to SCAQMD inspectors who had been responding to potential SCAQMD rule violations. In addition, each Coachella Valley jurisdiction has assigned a “dust czar” to coordinate dust control for that jurisdiction (e.g. dust plan review, ordinance enforcement, public and industry outreach, SCAQMD liaison). All “dust czars” have taken the Compliance Promotion Class and have worked with the SCAQMD inspector to address dust sources within their individual jurisdictions.

On October 4, 2002, the SCAQMD Board approved the FY 2002-03 AB 2766 MSRC Discretionary Fund Work Program in Concept totaling $14.95 million. This included the Coachella Valley PM10 Reduction Program; the total amount of Discretionary Funds allocated to this category was $1,000,000. The Coachella Valley Program offers to co-fund qualifying particulate matter reduction projects, focusing on the early implementation of Most Stringent Measures (MSMs) as defined by the SCAQMD in the new Coachella Valley State Implementation Plan. The goal of the MSRC Program is to assist CVAG jurisdictions in effectively and expeditiously implementing MSMs prior to the imposition of mandatory PM10 Reduction Rules by the SCAQMD. The MSRC Program provides qualifying CMAQ projects an 11.47 percent match against federal CMAQ (TEA-21) funds, a 75 percent match against AB 2766 Subvention Funds, and a 50 percent match when other sources of funds are applied. The solicitation mechanism is a Program Announcement and Application, with a proposal receipt period beginning on November 5, 2002 and ending on April 8, 2003. The funding was available on a first-come, first-serve basis and twelve projects were approved for a total of $1,000,000. Leveraged with CMAQ, AB2766 subvention, and other funds, this program resulted in over $5,000,000 of PM10 mitigation and control projects being initiated in the Coachella Valley. Details can be found in the 2003 February and March SCAQMD Governing Board agendas.

The Coachella Valley Air Quality Ad Hoc Task Force (CV Task Force), sponsored by CVAG, is assisting CVAG and the SCAQMD in implementing the 2002 CVSIP. The CV Task Force includes mayors and city council members of all Coachella Valley cities, a County Supervisor from Riverside County, tribal chairs or vice-chairs from all local

Indian tribes, CVAG Energy and Environmental Resources subcommittee members (city managers), the Coachella Valley Economic Partnership, and representatives from the local farm bureau, building industry association, developers, Caltrans, as well as staff from SCAQMD, ARB, and U.S. EPA. Other interested stakeholders, including SunLine Transit Agency, Coachella Valley Water District, Southern California Gas Company, the Building Industry Association (BIA), local developers, the Construction Industry Air Quality Coalition (CIAQC), local farmers, and the "dust czars," have also participated. The CV Task Force met on March 12, 2003, to review the initial drafts of the model ordinance, dust control handbook, and memorandum of understanding, which taken together, will implement the local government portion of the 2002 CVSIP control measures.

Localized Cumulative Impacts

Since the power plant air quality impacts can be reasonably estimated through air dispersion modeling (see Operational Modeling Analysis section) the project's contributions to localized cumulative impacts can be estimated. To represent past and, to an extent, present projects that contribute to ambient air quality conditions, the Commission staff recommends the use of ambient air quality monitoring data (see Environmental Setting section), referred to as the background. The staff undertakes the following steps to estimate what are additional appropriate present projects that are not represented in the background and reasonably foreseeable projects:

First, the Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within six miles of the project site. Beyond six miles there is little or no measurable cumulative overlap between stationary emission sources. The non-photochemical-reactant pollutant emission impacts of the criteria pollutant emissions (i.e., NOx, SOx, CO, PM10 and PM2.5) have, from staff's experience with air dispersion modeling, had a finite time and distance to remain airborne. In staff's experience of using the USEPA air dispersion models (SCREEN, ISCST3 and AERMOD), staff has never seen any proposed power plant having non-photochemical-reactant pollutant emission impacts which approach or go beyond 10 kilometers (or six miles). This effectively identifies all new emissions that emanate from a single point (e.g., a smoke stack), referred to as "point sources." The submittal of an air district application is a reasonable demarcation of what is "reasonably foreseeable". So, as an example, if the last year of ambient air quality monitoring data from area monitoring stations was 2003, then Commission staff (or the applicant) would ask the air district for all new applications that are not included in the ambient data.

Second, the Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final

Environmental Impact Reports (EIR) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is “reasonably foreseeable” for new area sources.

The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.

Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources are rare but include existing sources that are co-located with the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than 2 miles away.

When there are a large number of sources (in some cases 15 to 20 sources) and they are primarily of small emission quantities with higher impacts, the modeling results must be carefully interpreted so that they are not skewed towards the smaller, high-impacting sources. The reason being that while small sources can cause higher impacts, they are typically limited to within a hundred yards or similar close proximity of the source. Therefore, a cumulative interaction with the proposed project emission impacts is unlikely.

Once the modeling results are produced, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff’s cumulative impacts analysis, the applicant must submit a modeling protocol, based on informational requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the Data Adequacy phase of the licensing procedure. Staff typically assists the applicant in finding sources (as described above), characterizing those sources and interpreting the results of the modeling. However, the actual modeling runs are usually left to the applicant to complete. There are several reasons for this; modeling analyses take time to perform and require significant expertise, the applicant has already performed a modeling analysis of the project alone (see Operational Modeling Analysis section), and the applicant can act on its own to modify the project as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or applicant (see Mitigation section).

The SCAQMD identified 106 new potential point sources for the applicant and Energy Commission staff to review. Staff identified that there were no new area or point sources through the review of local EIRs, and the project is not co-located with other existing air emission sources. Staff reviewed the 106 new potential point sources identified by the SCAQMD: 5 were administrative changes that resulted in no new emissions, 5 were applications on hold or canceled, 61 were greater than 6 miles from the project site, 18 were replacements in kind of existing sources, and 17 were sources that emit VOC only (VOC is not modeled). Therefore, staff concludes that there are no new sources within six miles of the proposed project site that are required to be in the cumulative analysis. Therefore, the modeling results shown in AIR QUALITY Tables 13, 14 and 15 represent the project cumulative analysis as well as the project direct impacts analysis.

Chemically Reactive Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, the emissions of NOx and VOC from the CPV Sentinel project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts could be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards. However, emission offsets that would be provided by CPV Sentinel would reduce potential impacts to a level that would be cumulatively less than significant.

PM2.5 Impacts

The emissions of NOx and SOx from the CPV Sentinel project do have the potential (if left unmitigated) to cumulatively contribute to higher PM2.5 levels in the region. These impacts could be considered significant because they would contribute to ongoing violations of the state and federal PM2.5 ambient air quality standards. However, emission offsets that would be provided by CPV Sentinel would reduce potential impacts to a level that would be cumulatively less than significant.

COMPLIANCE WITH LORS

FEDERAL

The Prevention of Significant Deterioration (PSD) program requires major sources to obtain permits for emissions of attainment pollutants. A major source for a simple-cycle combustion turbine is defined as one whose emissions of attainment pollutants exceed 250 tons per year. Since the emissions of attainment pollutants from the CPV Sentinel project are not expected to exceed 250 tons per year, the PSD program does not apply. Thus the SCAQMD did not issue a PSD permit as part of their Final Determination of Compliance (FDOC) for the project.

STATE

The applicant will demonstrate that the project will comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the SCAQMD FDOC (issued April 30, 2008; revised February 28, 2010) and the Energy Commission staff's affirmative finding for the project. The project would also comply with Sections 21080, 39619.8, 40440.14 (AB1318) as noted in the SCAQMD Addendum to the FDOC (SCAQMD 2010).

LOCAL

Compliance with specific SCAQMD rules and regulations is discussed below via excerpts from the FDOC (SCAQMD 2008a, 2010). For a more detailed discussion of the compliance of the project, please refer to the FDOC (SCAQMD 2008a, 2010).

SCAQMD Regulation II-Permits

RULE 212-Standards for Approving Permits

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. A public notice will be issued followed by a 30-day public comment period prior to issuance of a permit. Compliance is expected.

SCAQMD Regulation IV-Prohibitions

RULE 401-Visible Emissions

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration that there will be visible emissions. Compliance is expected.

RULE 402-Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Compliance is expected.

RULE 403-Fugitive Dust

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust such as construction activities. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the CTGs is expected to comply with this rule.

RULE 407-Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will meet the BACT limit of 6.0 ppmvd @ 15 percent O_2, 1-hr average, and the turbines will be conditioned as such. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409-Combustion Contaminants

This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12 percent CO_2, averaged over 15 minutes. The equipment is expected to meet this limit.

RULE 431.1-Sulfur Content of Gaseous Fuels

CPV Sentinel will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H_2S, specified in this rule.

RULE 475-Electric Power Generating Equipment

Requirements of the rule specify that the equipment must comply with a PM10 mass emission limit of 11 lb/hr or a PM10 concentration limit of 0.01 grains/dscf. The PM10 mass emissions from the CPV Sentinel project turbines are estimated to be 6 lb/hr. Therefore, compliance is expected.

Regulation XIII – New Source Review

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – LMS100 CTGs

These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. The applicant has provided a performance warranty which accompanied the initial application package which indicates that each LMS100 operating on a simple cycle can comply with, and for NOx, even exceed the BACT requirements. SCAQMD now considers the more restrictive 1-hour averaging times to be achieved in practice and CPV Sentinel will therefore be required to comply with the 1-hour averages for NOx, CO, and VOC as opposed to the three hour as was proposed. The proposed project emission characteristics are lower than that required by BACT for the combustion turbines, therefore compliance is expected.

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – Emergency Fire Pump

The emergency fire pump is required to employ BACT because the maximum daily emissions from this source are expected to exceed 1 lb/day. CPV Sentinel will be required to evaluate the technological feasibility of using a particulate trap on the emergency fire pump. In the event that it is not technologically feasible to install a particulate trap to control PM10 emissions, the Tier III BACT levels will apply to the emergency fire pump. BACT for SOx emissions for compression ignition emergency fire pumps is diesel fuel with a sulfur content no greater than 0.0015 percent by weight. The manufacturer has indicated that this engine can comply with the Tier III emission levels and the user will only purchase diesel fuel with a sulfur content of no greater than 0.0015 percent by weight. The emergency fire pump is expected to comply with BACT.

RULE 1303(a)-BACT – Cooling Tower

Rule 219(e)(3) provides an exemption for water cooling towers and water cooling ponds not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained. The eight cooling towers being proposed at CPV Sentinel will meet the requirements of Rule 219(e)(3) and is therefore exempt from NSR. BACT therefore does not apply.

RULE 1303(a)-BACT – Ammonia Storage Tank

A pressure relief valve that will be set at no less than 25 psig will control ammonia emissions from the storage tank. In addition, a vapor return line will be used to control ammonia emissions during storage tank filling operations. Based on the above, compliance with BACT requirements is expected.

RULE 1303(b)(1) and Rule 2005(b)(1)(B) - Modeling

The applicant has conducted air dispersion modeling using the U.S. EPA AERMOD air dispersion model. The Tier 4 Health Risk Assessment was conducted in accordance with guidelines set forth by the California Office of Environmental Health Hazard Assessment (OEHHA) and the California Air Resources Board (CARB). The OEHHA/CARB computer program (HARP) was used to determine the health risk assessment. SCAQMD staff's review of the modeling and HRA analyses concluded that the applicant used U.S. EPA AERMOD along with the appropriate model options in the analysis for NO_2, CO, PM10, and SO_2. The applicant modeled both the cumulative and individual permit unit impacts for the project. No significant deficiencies in methodology were noted. Therefore, the applicant is expected to comply with BACT for the ammonia storage tank.

RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets – LMS100 PA CTGs

Since CPV Sentinel is a new facility with an emissions increase, offsets will be required for all criteria pollutants. CPV Sentinel will be included in NOx RECLAIM and as such, NOx increases will be offset with RTCs at a 1.0 to1 ratio. Non-RECLAIM criteria pollutants (CO, VOC, SOx, and PM10) will be offset by either the purchase of Emission Reduction Credits (ERCs) and/or other means, as allowed under District Rules and

Regulations at a 1.2 to 1 ratio. CPV Sentinel has indicated that the required amounts of offsets will be provided prior to issuance of the Facility Permit. Compliance with offset requirements of Rules 1303(b)(2) and 2005(b)(2) is expected.

RULES 1303(b)(3)-Sensitive Zone Requirements and 2005(e)-Trading Zone Restrictions

Both rules state that ERCs must be obtained from the appropriate trading zone. In the case of Rule 1303(b)(3), unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health & Safety Code Section 40410.5. CPV Sentinel is located in Zone 2a and is therefore eligible to obtain its ERCs from either Zone 1 or Zone 2a. Similarly in the case of Rule 2005(e), CPV Sentinel, because of its location may obtain RECLAIM Trading Credits (RTCs) from either Zone 1 or Zone 2, at its choosing. Compliance is expected with both rules.

RULE 1303(b)(4)-Facility Compliance

The new facility will comply with all applicable Rules and Regulations of the SCAQMD.

RULE 1303(b)(5)-Major Polluting Facilities

Rule 1303(b)(5)(A) – Alternative Analysis

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the CPV Sentinel project and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. The applicant has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility. Compliance is expected.

Rule 1303(b)(5)(B) – Statewide Compliance

The applicant has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, the applicant has submitted an email to the SCAQMD dated October 19, 2006 stating that “any and all facilities that the applicant owns or operates in the State of California (including the proposed CPV Sentinel project) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act.” Therefore, compliance is expected.

Rule 1303(b)(5)(C) – Protection of Visibility

Modeling is required if the source is within a Class I area and the NOx and PM10 emissions exceed 40 TPY and 15 TPY respectively. Since the nearest Class I area is located over 28 miles from the proposed CPV Sentinel project site, modeling for plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected.

Rule 1303(b)(5)(D) – Compliance through CEQA

The Energy Commission is the Lead Agency under CEQA. Since the applicant is required to receive a certification from the Energy Commission, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

REGULATION XVII-PREVENTION OF SIGNIFICANT DETERIORATION

The SCAQMD Governing Board, in its action on February 7, 2003, authorized the Executive Officer, upon withdrawal of the U.S. EPA Prevention of Significant Deterioration (PSD) delegation, not to request any further delegation and to allow the U.S. EPA to terminate the SCAQMD's PSD delegation agreement and for U.S. EPA to become the permitting agency for PSD sources in the SCAQMD.

The Board determined that Regulation XVII is inactive upon U.S. EPA's withdrawal of delegation and shall remain inactive unless and until the U.S. EPA provides the SCAQMD with new delegation of authority to act either in full or on a Facility/Permit-Specific basis. The delegation was rescinded on March 3, 2003, by U.S. EPA.

The SCAQMD Governing Board in its April 1, 2005, meeting reaffirmed its previous action on February 7, 2003, to relinquish PSD analysis back to federal government and render Regulation XVII inactive unless the SCAQMD receives new delegation in part or in full from the U.S. EPA.

Based on the Governing Board's actions, this rule is ineffective and no analysis is required for any pollutant subject to federal PSD requirement. The SCAQMD has sent the applicant a notification to contact the U.S. EPA directly for applicability of PSD to the proposed project. SCAQMD sent a letter to the applicant on December 8, 2005, and instructed the applicant to contact U.S. EPA directly regarding implementation of PSD. PSD requires major sources to obtain permits for attainment pollutants. A major source for a simple-cycle combustion turbine is defined as any one pollutant exceeding 250 tons per year. Since the emissions from the CPV Sentinel project are not expected to exceed 250 tons per year, PSD does not apply.

REGULATION XX-RECLAIM

Rule 2005(g) – Additional Requirements

As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, CPV Sentinel has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below. Compliance is expected.

Rule 2005(g)(1) – Statewide Compliance

The applicant has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, the applicant has submitted an email to the SCAQMD dated October 19, 2006 stating that "any and all facilities that the applicant owns or operates in the State of California (including the proposed CPV Sentinel project) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 2005(g)(2) – Alternative Analysis

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the CPV Sentinel project and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. The applicant has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility. Compliance is expected.

Rule 2005(g)(3) – Compliance through CEQA

The Energy Commission is the Lead Agency under CEQA. Since the applicant is required to receive certification from the Energy Commission, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

Rule 2005(g)(4) – Protection of Visibility

Modeling is required if the source is within a Class I area and the NOx emissions exceed 40 TPY. Since the nearest Class I area is located over 28 miles from the proposed CPV Sentinel project site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected.

Rule 2005(h) – Public Notice

CPV Sentinel will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

Rule 2005(i) – Rule 1401 Compliance.

CPV Sentinel will comply with Rule 1401 as demonstrated in the Tier 4 analysis and subsequently reviewed and found to be satisfactory by SCAQMD modeling staff. Compliance is expected.

Rule 2005(j) – Compliance with State and Federal NSR.

CPV Sentinel will comply with the provisions of this rule by having demonstrated compliance with SCAQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

"All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur."

Staff interprets this requirement to include the construction equipment used on all linear construction elements as well as the main construction site.

California Communities Against Toxics

Staff received comments from California Communities Against Toxics (CCAT 2010) regarding CPV Sentinel. Staff has the following responses to the comments submitted regarding air quality.

Comment 1: The calculations for SO_2 and PM10 emissions from the facility assume usage of natural gas with a sulfur content of.25 lb grains/100 scf (see, e.g., SCAQMD Engineering Analysis/Evaluation ("EA/E") at 20 and 32; and Permit Condition B61.1). Southern California Gas Company (SCGC) gas quality is regulated by Rule No. 30, Transportation of Customer-Owned Gas. Rule No. 30, Section I(e), specifies that gas shall not contain more than 0.75 grain of sulfur per 100 standard cubic feet (scf). The information provided by The Gas Company does not support the use of .25 gr/100 scf standard for emissions calculations.

Response to Comment 1: Historically, SCGC has delivered natural gas that does not exceed a sulfur content of.25 lb grains/100 scf on an annual average basis. Condition of Certification **AQ-6** specifically requires that the natural gas shall not exceed H_2S concentrations of more than 0.25 gr/100scf on an annual average of the monthly samples of gas composition or gas supplier documentation. Should gas quality fail to meet this sulfur limit in the future, CPV Sentinel would not be able to meet their permit conditions and would have to amend their permit and provide additional offsets.

Comment 2: CPV Sentinel proposes to use an Emergency Fire Pump Engine that meets EPA's Tier II standards. According to the SCAQMD Engineering Analysis/Evaluation, however, "EPA will require the engines to meet Tier III standards in 2009." EA/E at 35. Does the proposed Emergency Fire Pump Engine meet the applicable standards?

Response to Comment 2: CPV Sentinel has proposed to use a Tire III engine that will meet all applicable emission standards.

Comment 3: The EPA has proposed a NESHAPS for compression ignition engines. At the time the permit was written by the AQMD the rule language was not available and AQMD indicated that it would "evaluate[] at a later date" how this rule would impact this permit. EA/E at 53. Has this analysis been undertaken?

Response to Comment 3: The firewater pump complies with the current NESHAPS for compression ignition engines. CPV Sentinel will utilize a CARB

Tier III engine that also complies with the EPA NESHAPS for compression ignition engines.

Comment 4: SCAQMD has not adopted any Rule or Regulation that allows for the transfer of ERCs to electrical generating facilities. In addition, any Rule or Regulation adopted or relied upon by the SCAQMD to allow such a transfer would require submission to, and approval by, the U.S. Environmental Protection Agency since any such change would be an amendment to the SCAQMD's portion of the State Implementation Plan.

Response to Comment 4: Under federal, state and local laws, rules and regulations, it is required that emission increases of specified nonattainment air contaminants and their precursors be offset for the CPV Sentinel. The SCAQMD prepared a pollutant specific evaluation for compliance with local, state and federal laws based on SCAQMD Regulations XIII (Rule 1303) and XX (Rule 2005); the federal Clean Air Act and NSR Regulations; and State of California Clean Air Act No Net Increase and Assembly Bill (AB) 1318 provisions.

Emission offsets for Volatile Organic Compounds (VOCs) will be provided by CPV Sentinel in the form of Emission Reduction Credits (ERCs) purchased by CPV Sentinel in the open market pursuant to AQMD Regulation XIII (Rule 1303). Emission offsets for Nitrogen Oxides (NOx) will also be provided by CPV Sentinel in the form of RECLAIM Trading Credits (RTCs) purchased by CPV Sentinel in the open market pursuant to AQMD Regulation XX (Rule 2005). Emission offsets for Sulfur Oxides (SOx) and Particulate Matter-less than 10 micron in diameter-(PM10) will be provided by AQMD from offset credits pursuant to AB 1318 (Health & Safety Code Section 40440.14(a)). CPV Sentinel will pay AQMD mitigation fees for SOx and PM10 offsets, which in turn AQMD will invest in emission reduction projects pursuant to AB 1318.

The CPV Sentinel offset evaluation for SOx and PM10, which is provided under the SCAQMD Determination of Compliance to the Energy Commission, pursuant to AB 1318 (Health & Safety Code Section 40440.14(c)), will also be submitted to the U.S. Environmental Protection Agency (EPA) for approval and inclusion into the State Implementation Plan (SIP).

Comment 5: If CPV Sentinel is proposing to rely upon recently enacted state legislation to meet the federal offset requirements, then there are several requirements established in the statute including, but not limited to:

a. "The District shall make any necessary submission to the United State Environmental Protection Agency with regard to the crediting and use of emission reductions and shutdowns from minor sources;"

b. On or before March 1, 2010, the AQMD shall report to the CEC "the emission credits to be credited and transferred" to CPV Sentinel;

c. CPV Sentinel must have “a purchase agreement executed on or before December 31, 2008 to provide electricity to a public utility”;

d. CPV Sentinel must pay “mitigation fees set forth in the south coast district’s Rule 1309.1, as adopted on August 3, 2007;”

e. For any fees collected AQMD “shall ensure that at least 30 percent of the fees are used for emission reduction in areas with close proximity” to the facility and “at least 30 percent are used for emission reductions in areas designated as `Environmental Justice Areas’ in Rule 1309.1”; and

f. The CEC must determine if the credit and transfer “satisfy all applicable legal requirements,” including those found in the federal Clean Air Act.

<u>Response to Comment 5:</u> The SCAQMD (2010) Addendum to Determination of Compliance (DOC), Appendix N contains a detailed discussion of the ERC’s that are proposed for the CPV Sentinel project. Attachment 1 to Appendix N provides an AB 1318 Tracking System to address the specific implementation requirements and demonstrate compliance with the Clean Air Act.

CONCLUSIONS

Staff finds that with the adoption of the attached conditions of certification the proposed CPV Sentinel Energy Project (CPV Sentinel) would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related impacts. Staff also finds that:

The project would comply with applicable South Coast Air Quality Management District (SCAQMD) Rules and Regulations, including New Source Review (NSR) requirements (SCAQMD 2010a).

The project would not cause new violations of any NO_2, SO_2, or CO ambient air quality standards, and therefore, the project direct NOx, SOx and CO emission impacts are not significant. The analyses did not need to include the new federal 1-hour NO_2 ambient air quality standard because it was not in effect at the time the project application was filed with the district and the Energy Commission.

Without proper mitigation, the project NOx and VOC emissions would potentially contribute to existing violations of the state 1-hour and the federal 8-hour ozone air quality standards. Staff has determined that emission offset credits from the South Coast Air Basin would mitigate the project’s contribution to ozone impacts to a level that is not cumulatively considerable (**AQ-SC8**).

Without mitigation, the project PM10 emissions and PM10 precursor emissions of SOx would contribute to the existing violations of the state 24-hour PM10 air quality standard. However, staff has determined that emission reductions credits would mitigate the project's contribution to PM10 and PM10 precursor emissions impacts to a level that is not cumulatively considerable.

Without mitigation, the project PM2.5 emissions and PM2.5 precursor emissions of SOx would contribute to existing violations of the federal 24-hour PM2.5 or the state annual PM2.5 air quality standard. Therefore, potential impacts are considered significant. However, staff has determined that emission reduction credits would mitigate the project's contribution to PM2.5 impacts to a level that is not cumulatively considerable.

The project meets the requirements of Assembly Bill 1318 to qualify for obtaining emission offsets from the SCAQMD's internal offset account.

- Staff has analyzed the potential incremental greenhouse gas (GHG) emission impacts from the proposed project and concludes that they are not cumulatively considerable and thus do not represent a significant impact under the California Environmental Quality Act (CEQA). Refer to the Greenhouse Gas Appendix for details.

Staff proposes the following conditions of certification that include the SCAQMD proposed conditions from the FDOC with appropriate staff proposed verification language for each condition.

The Staff has proposed a number of permit conditions that are in addition to the permit conditions that the SCAQMD has proposed in the FDOC. In most cases the staff proposed permit conditions deal with air quality issues that the SCAQMD is not required to address. Conditions **AQ-SC1** through **AQ-SC5** are construction-related permit conditions. Condition AQ-SC6 requires that the project owner use vehicles meeting current emission standards for project operations and maintenance. Condition **AQ-SC7** deals with the administrative procedures for project modifications. Condition **AQ-SC8** is a reporting requirement for the providing of emission offsets. Condition **AQ-SC9** is a quarterly emission reporting requirement. Conditions **AQ-SC10** and **AQ-SC11** are cooling tower permit requirements. Staff proposes these conditions for the operation of the cooling towers because the SCAQMD does not consider cooling towers as permit units (see discussion of SCAQMD rule 1303(a)-BACT for Cooling Towers above), and thus they do not include permit conditions. However staff believes that they are potential sources of PM10/PM2.5, as shown in our analysis, and thus permit limits and verifications of those permit limits should be proposed. Conditions **AQ-1** through **AQ-16** are the SCAQMD permit conditions with staff proposed verification language added. Condition **AQ-2** incorporates a SCAQMD rule regarding emissions limit compliance for NOx emissions within the RECLAIM program.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **AIR QUALITY APPENDIX AIR-1**. The CPVS project would meet the Emission Performance Standard under all reasonable operating scenarios. Mandatory reporting of the GHG emissions is required as part of the Air Resources Board's greenhouse gas regulations and this may enable the ARB to implement trading markets (see **AIR QUALITY APPENDIX AIR-1**). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as GHG regulations become more fully developed and implemented.

PROPOSED CONDITIONS OF CERTIFICATION

The SCAQMD has a unique system of structuring and numbering their permit conditions. In order for the reader to avoid confusion between how the SCAQMD numbers their permit conditions and how the Energy Commission staff normally numbers permit conditions, the staff prepared the following table that cross references the conditions in the FDOC with the conditions presented by staff in this analysis.

AIR QUALITY Table 22
SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
Combustion Turbines		
A63.1	AQ-1	Monthly contaminant emission limit (PM10, CO, SOx & VOC) Units 1-5
A63.2	AQ-1	Monthly contaminant emission limit (PM10, CO, SOx, & VOC) Units 6-8
SCAQMD Rule 2004	AQ-2	Annual contaminant emissions limit (NO_2).
A99.1	AQ-3	Relief from 2.5ppm NOx limit during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year. Units 1-8
A99.3	AQ-3	Relief from 4.0 ppm CO limits during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year. Units 1-8
A99.5	AQ-3	NOx limit during the turbine commissioning, not to exceed 12 months.
A99.7	AQ-3	NOx limit for interim time period of end of commissioning to continuous emission monitoring system (CEMS) certification, not to exceed 12 months.

AIR QUALITY Table 22
SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
A99.9	AQ-3	Relief from 2.0 ppm VOC limit during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year. Units 1-5
A99.10	AQ-3	Relief from 2.0 ppm VOC limit during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year. Units 6-8
A195.1	AQ-4	CO emission limit of 4.0 ppm @ 15% O_2 averaged over 1-hour.
A195.2	AQ-4	NOx emission limit of 2.5 ppm @ 15% O_2 averaged over 1-hour.
A193.3	AQ-4	VOC emission limit of 2.0 ppm @ 15% O_2 averaged over 1-hour.
A327.1	AQ-5	Relief from emission limits, under Rule 475; project may violate either the mass emission limit or concentration emission limit, but not both at the same time.
A433.1	AQ-3	NOx emission limit during startup. Units 1-8
B61.1	AQ-6	H_2S concentration limit for natural gas.
C1.1	AQ-6	Limits the fuel usage for each turbine to 418 mmcf per month (non-commissioning). Units 1-5
C1.2	AQ-6	Limits the fuel usage for each turbine to 598 mmcf per month (non-commissioning). Units 6-8
C1.3	AQ-6	Limits the fuel usage for each turbine to 301 mmcf per month (commissioning).
C1.6	AQ-6	Limits the fuel usage for each turbine to 2,411 mmcf per year (non-commissioning). Units 1-5.
C1.7	AQ-6	Limits the fuel usage for each

AIR QUALITY Table 22
SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
		turbine to 2,928 mmcf per year (non-commissioning). Units 6-8.
D12.1	AQ-6	Requires the installation of a fuel flow meter.
D29.1	AQ-7	Requires source tests for specific pollutants (NOx, CO, SOx, VOC, PM10, NH3) within 180 days of initial startup.
D29.2	AQ-8	Requires source tests for ammonia (NH3); quarterly for the first year and annually thereafter.
D29.3	AQ-7	Requires source tests for specific pollutants (Sox, VOC, PM10) once every three years.
D82.1	AQ-9	Requires the installation of CEMS for CO emissions.
D82.2	AQ-9	Requires the installation of CEMS for NOx emissions.
E193.1	AQ-SC9	Requires that the turbines be operated within the mitigation measures stipulated in the Commission Decision.
E193.3	AQ-3	Requires the project to be operational within 3 years of the issuance of the permit to construct.
H23.1	NA	Establishes the applicability of 40CFR60 Subpart KKKK for the project contaminant NOx and SOx.
I296.1	AQ-16	Prohibited from operation unless the operator hold sufficient RTCs for the CTGs. Units 1-8
K40.1	AQ-7, -8 & -9	Source test reporting requirements.
K67.1	AQ-10	Requires record keeping of fuel use during commissioning, prior to and after CEMs certification.
SCR/CO Catalyst		
A195.4	AQ-11	Establishes the 5 ppm ammonia

AIR QUALITY Table 22
SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
		slip limit.
D12.2	AQ-12	Requires a flow meter for the ammonia injection.
D12.3	AQ-13	Requires a temperature meter at the SCR inlet.
D12.4	AQ-14	Requires a pressure gauge to measure the differential pressure across the SCR grid.
E179.1	AQ-12 & -13	Defines "continuously record" for D12.2 and D12.3 as recording once an hour based on the average of continuous monitoring for that hour.
E179.2	AQ-14	Defines "continuously record" for D12.4 as recording once a month based on the average of continuous monitoring for that month.
E193.1	AQ-SC9	Requires that the SCR/CO catalyst be operated within the mitigation measures stipulated in the Commission Decision.
Ammonia Storage Tank		
C157.1	See Hazardous Material section	Requires the installation of a pressure relief valve.
E144.1	See Hazardous Material section	Requires venting of the storage tank during filling only to the vessel from which it is being filled.
E193.1	AQ-SC9	Requires that the Ammonia Storage Tank be operated within the mitigation measures stipulated in the Commission Decision.
K67.2	See Hazardous Material section	Requires record keeping in the manner approved by the District Executive Officer.
Emergency Firewater Pump		
C1.4	AQ-15	Limited to 50 hours per year (for operation and ready test firing).

AIR QUALITY Table 22
SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
D12.5	AQ-15	Requires the installation of a non-resettable time meter.
B61.2	AQ-15	Restricts the sulfur content of the diesel fuel to no more than 15 ppm by weight.
E193.1	AQ-SC9	Requires that the firewater pump be operated within the mitigation measures stipulated in the Commission Decision.
I296.2	AQ-16	Prohibited from operation unless the operator holds sufficient RTCs for the firewater pump.
K67.2	AQ-15	Required record keeping for the firewater pump.
Portable Architectural Coating Equipment		
K67.5	NA	Required record keeping of thinners and no-thinners architectural applications (paint).

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the Energy Commission's Compliance Project Manager (CPM) for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates. The AQCMM and all delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCMP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes from leaving the project. Any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report (**COMPLIANCE-6**) to include the following to demonstrate control of fugitive dust emissions:

A. A summary of all actions taken to maintain compliance with this condition;

B. Copies of any complaints filed with the District in relation to project construction; and

C. Any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

   1. The following fugitive dust mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**.

      A. The main access roads through the facility to the power block areas will be either paved or stabilized using soil binders, or equivalent methods, to provide a stabilized surface that is similar for the purposes of dust control to paving, that may or may not include a crushed rock (gravel or similar material with fines removed) top layer, prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved prior to taking initial deliveries.

      B. All unpaved construction roads and unpaved operation site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading; and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

C. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

D. Visible speed limit signs shall be posted at the construction site entrances.

E. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

F. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

G. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

H. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

I. Construction areas adjacent to any paved roadway below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this condition does not conflict with the requirements of the SWPPP.

J. All paved roads within the construction site shall be swept daily or as needed (less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

K. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

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

M. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

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

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported (A) off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner or (B) 200 feet beyond the centerline of the construction of linear facilities indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, if the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report (**COMPLIANCE-6**) to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the District in relation to project construction; and

C. any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report, a construction mitigation report that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related emissions. Any deviation from the AQCMP mitigation measures shall require prior and CPM notification and approval.

<u>Verification:</u> The AQCMM shall include in the Monthly Compliance Report (**COMPLIANCE-6**) the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. A list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM, and the AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

The following off-road diesel construction equipment mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**.

a. All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

b. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

c. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless a good faith effort to the satisfaction of the CPM that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. In the event that a Tier 3 engine is not available for any off-road equipment larger than 100 hp, that equipment shall be equipped with a Tier 2 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NOx) and diesel particulate matter (DPM) to no more than Tier 2 levels unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" for the following, as well as other, reasons.

    1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question to Tier 2 equivalent emission levels and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or

    2. The construction equipment is intended to be on site for 5 days or less.

    3. The CPM may grant relief from this requirement if the AQCMM can demonstrate

a good faith effort to comply with this requirement and that compliance is not practical.

d. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and that a replacement for the equipment item in question meeting the controls required in item “b” occurs within 10 days of termination of the use, if the equipment would be needed to continue working at this site for more than 15 days after the use of the retrofit control device is terminated, if one of the following conditions exists :

   1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.

   2. The retrofit control device is causing or is reasonably expected to cause engine damage.

   3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

   4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

e. All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (b) above shall be properly maintained and the engines tuned to the engine manufacturer’s specifications.

f. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

g. Construction equipment will employ electric motors when feasible.

AQ-SC6 The project owner, when obtaining dedicated on-road or off-road vehicles for facility maintenance activities, shall only obtain new model year vehicles that meet California on-road vehicle emission standards or appropriate U.S.EPA/California off-road engine emission standards for the model year when obtained.

Verification: At least 60 days prior to the start commercial operation, the project owner shall submit to the CPM a copy of the plan that identifies the size and type of the on-site vehicle and equipment fleet and the vehicle and equipment purchase orders and contracts and/or purchase schedule. The plan shall be updated every other year and submitted in the Annual Compliance Report (**COMPLIANCE-7**).

AQ-SC7 The project owner shall provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility.

The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed air permit modifications to the CPM within 5 working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC8 The project owner shall provide emission reduction credits to offset turbine exhaust and emergency equipment NOx, VOC, SOx, PM10 and PM2.5 emissions in the form and amount required by the District. RECLAIM Trading Credits (RTCs) shall be provided for NOx as is necessary to demonstrate compliance with Condition of Certification **AQ-16**.

Emission reduction credits (ERCs) shall be provided for SOx (,13,928 lb/year includes offset ratio of 1.0), PM10 (118,120 lb/year, includes offset ratio of 1.0) and VOC (441 lb/day, includes offset ratio of 1.2).

The project owner shall surrender the ERCs for SOx, VOC and PM10 from among those that are listed in the table below or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions of credits listed.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) will not cause the project to result in a significant environmental impact, and the SCAQMD confirms that each requested change is consistent with applicable federal and state laws and regulations.

The project owner shall request from the SCAQMD a report of the NSR Ledger Account for the project after the SCAQMD has issued the Permit to Construct. This report is to specifically identify the ERCs used to offset the project emissions.

Certificate Number	Amount (lbs/day)	Pollutant
AQ007877	348	VOC
AQ007879	64	VOC
To be determined (TBD)	TBD	TBD

Verification: The project owner shall submit to the CPM the NSR Ledger Account, showing that the project's offset requirements have been met, 15 days prior to initiating construction for Priority Reserve credits, and 30 days prior to turbine first fire for traditional ERCs. Prior to commencement of construction, the project owner shall obtain sufficient RTCs to satisfy the District's requirements for the first year of operation as prescribed in Condition of Certification **AQ-16**. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC9 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the Conditions of Certification herein. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

<u>Verification:</u> The project owner shall submit the Quarterly Operation Reports to the CPM and APCO no later than 30 days following the end of each calendar quarter.

AQ-SC10 The project owner shall perform quarterly cooling tower recirculating water quality testing, or shall provide for continuous monitoring of conductivity as an indicator, for total dissolved solids content.

<u>Verification:</u> The project owner shall submit to the CPM cooling tower recirculating water quality tests or a summary of continuous monitoring results and daily recirculating water flow in the Quarterly Operation Report (**AQ-SC9**). If the project owner uses continuous monitoring of conductivity as an indicator for total dissolved solids content, the project owner shall submit data supporting the calibration of the conductivity meter and the correlation with total dissolved solids content at least once each year in a Quarterly Operation Report (**AQ-SC9**).

AQ-SC11 The cooling towers daily PM10 emissions shall be limited to 18.82 lb/day in total for all eight cooling tower cells. The cooling towers shall be equipped with a drift eliminator to control the drift fraction to 0.0005 percent of the circulating water flow. The project owner shall estimate daily PM10 emissions from the cooling towers using the water quality testing data or continuous monitoring data and daily circulating water flow data collected on a quarterly basis. Compliance with the cooling tower PM10 emission limit shall be demonstrated as follows:

PM10 = cooling water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate.

<u>Verification:</u> The project owner shall submit to the CPM daily cooling tower PM10 emission estimates in the Quarterly Operation Report (**AQ-SC9**).

AQ-1 The project owner shall limit the emissions from **<u>each</u>** gas fired combustion turbine train exhaust stack as follows:

Units 1 through 8

Contaminant	Emissions Limit
PM10	2,428 lbs in any one month
CO	6,477 lbs in any one month
SOx	293 lbs in any one month
VOC	1,425 lbs in any one month

For the purpose of this condition, the limit(s) shall be based on the emissions from a single exhaust stack.

The project owner shall calculate the emission limit(s) by using the monthly fuel use data and the following emission factors: PM10: 6.97 lb/mmscf, VOC: 2.189 lb/mmscf & SOx: 0.71 lb/mmscf.

Compliance with the CO emission limit shall be verified through valid CEMS data.

The project owner shall calculate the emission limit(s) for CO for the purpose of determining compliance with the monthly emission limit in the absence of valid CEMS data by using the following emission factor(s):

A. During the commissioning period and prior to CO catalyst installation: 38.48 lb/mmscf.

B. After installation of the CO catalysis but prior to CO CEMS certification testing: 18.73 lb/mmscf the emission rate shall be recalculated in accordance with Condition AQ-10 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.

C. After CO CEMS certification testing: 18.73 lb/mmscf After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with Condition AQ-10 shall be used to calculated emissions.

For the purpose of this condition, the limit(s) shall be based on the emissions from a single turbine. During Commissioning, the CO emissions shall not exceed 11,602 lbs/month and the VOC emissions shall not exceed 620 lbs/month.

The project owner shall provide the AQMD with written notification of the date of initial CO catalyst use within (7) days of this event.

For the purpose of this condition the turbine shall not commence with normal operation until the commissioning process has been completed. Normal operations may proceed in the same commissioning month provided the project owner follows the requirements listed below.

The project owner shall calculate the commissioning emissions for VOC, SOx and PM10) for the commissioning month (beginning of the month to the last day of commissioning) using the equation below and the following emission factors: VOC: 2.06 lb/mmcf; PM10: 2.99 lb/mmcf; and SOx: 0.12 lb/mmcf.

The commissioning emissions for VOC, SOx, and PM10 shall be subtracted from the monthly emissions limits (listed in the table at the top of this condition) and the revised monthly emission limits will be the maximum emissions allowed for the remaining of the month.

For the purpose of this condition, the term "normal operations" is defined as the turbine is able to supply electrical energy to the power grid.

Verification: The project owner shall submit all emission calculations, fuel use, CEM records and a summary demonstrating compliance of all emission limits stated in this Condition for approval to the CPM on a quarterly basis in the quarterly emissions report (**AQ-SC10**).

AQ-2 The project owner/operator shall not produce emissions of oxides of nitrogen from the facility, including the firewater pump and all eight gas turbines combined, that exceed the RECLAIM Trading Credits holdings required in Condition of Certification **AQ-16** within a calendar year.

Verification: The project owner/operator shall submit to the CPM no later than 60 days following the end of each calendar year, the SCAQMD required (via Rule 2004) Quarterly Certification of Emissions (or equivalent) for each quarter and the Annual Permit Emissions Program report (or equivalent) as prescribed by the SCAQMD Executive Officer.

AQ-3 The 2.5 ppm NOx emission limit, the 2.0- ppm VOC limit and the 4.0 ppm CO emission limit shall not apply during turbine commissioning, start-up and shutdown. The commissioning period shall not exceed 150 operating hours per turbine from the initial start-up. Following commissioning, start-ups shall not exceed 25 minutes and shutdowns shall not exceed 10 minutes. Written records of commissioning, start-ups and shutdowns shall be kept and made available to SCAQMD and submitted to the CPM for approval. Emissions of NOx shall not exceed 29.52 lbs/hr for any hour in which a startup occurs. Units 1 through 8 shall be limited to a maximum of 300 startups per year;

The 19 lb/mmscf NOx emission limit(s) shall only apply during interim reporting period during initial turbine commissioning and the 12.40 lbs/mmscf shall apply only during the interim reporting period after the initial turbine commissioning period, to report RECLAIM emissions. The interim period shall not exceed 12 months from the initial start-up date.

For this condition startup shall be defined as the start up process to bring the turbine in full successful operations. If during startup the process is aborted and the startup is restarted, then the startup and restart is defined as one startup. In this case the startup time shall not exceed 1 hour.

The project owner/operator shall complete construction and the project shall be fully operational within three years of the issuance of the permit to construction from the District.

Verification: The project owner shall provide the SCAQMD and the CPM with the written notification of the initial start-up date no later than 60 days prior to the startup date. The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with this condition and the emission limits of Condition **AQ-13**. The monthly commissioning status report shall include criteria pollutant emission estimates for each commissioning activity and total commissioning emission estimates. The monthly commissioning status report shall be submitted to the CPM until the report includes the completion of the initial commissioning activities. The project owner shall provide start-up and shutdown occurrence and duration data as part as part of the Quarterly Operation Report (**AQ-SC10**) including records of all aborted turbine startups. The project owner shall make the site available for inspection of the commissioning and startup/shutdown records by representatives of the District, CARB and the Commission.

AQ-4 Each combustion turbine stack shall have the following emission limitations.

- PPM NOx emission averaged over 60 minutes at 15 percent oxygen, dry basis.
- 4.0 ppm CO emission averaged over 60 minutes at 15 percent oxygen, dry basis.
- 2.0 ppm VOC emission averaged over 60 minutes at 15 percent oxygen, dry basis.
- 5.0 ppm NH_3 emission averaged over 60 minutes at 15 percent oxygen, dry basis.

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC10**.

AQ-5 The project owner may at no time purposefully exceed either the mass or concentration emission limits set forth in Conditions of Certification **AQ-1, -2, -3** or **-4**.

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC10**.

AQ-6 The project owner shall limit the fuel usage during a commissioning period from each turbine to no more than 301 mmscf of pipeline quality natural gas per month. After the completion of commissioning, units 1 through 8 shall limit the fuel usage from each turbine to no more than 418 mmcf in any one non-commissioning calendar month and 2,411 mmcf in any one non-commissioning year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The operator shall install and maintain a fuel flow meter and recorder to accurately indicate and record the fuel usage being supplied to each turbine. The natural gas shall not exceed H_2S concentrations of more than 0.25 gr/100scf on an annual average of the monthly samples of gas composition or gas supplier documentation. The natural gas fuel sample shall be tested using District Method 307-91 for total sulfur calculated as H_2S.

Verification: The project owner shall submit to the CPM for approval all fuel usage records on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC10**.

AQ-7 The project owner shall conduct an initial source test for NOx, CO, SOx, VOC, NH_3 and PM10 and periodic source test every three years thereafter for NOx, CO, SOx, VOC and PM10 of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the SCAQMD and the CPM 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of SCAQMD Rule 304, and a description of all sampling and analytical procedures.
- The initial source test shall be conducted no later than 180 days following the date of first fire.
- The SCAQMD and CPM shall be notified at least 10 days prior to the date and time of the source test.
- The source test shall be conducted with the gas turbine operating under maximum, average and minimum loads.
- The source test shall be conducted to determine the oxygen levels in the exhaust.
- The source test shall measure the fuel flow rate, the flue gas flow rate and the turbine generating output in MW.
- The source test shall be conducted for the pollutants listed using the methods, averaging times, and test locations indicated and as approved by the CPM as follows:

Source Test Requirements

Pollutant	Method	Averaging Time	Test Location
NOx	SCAQMD Method 100.1	1 hour	Outlet of SCR
CO	SCAQMD Method 100.1	1 hour	Outlet of SCR
SOx	District Method 307.91	N/A	Fuel Sample
VOC	District Method 25.3	1 hour	Outlet of SCR
PM10	District Method 5	4 hours	Outlet of SCR
Ammonia	SCAQMD Methods 5.3 and 207.1 or U.S. EPA Method 17.	1 hour	Outlet of SCR

- The source test results shall be submitted to the SCAQMD and the CPM no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
  1. ppmv corrected to 15 percent oxygen dry basis,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned and
  4. additionally, for PM10 only, grains per dry standard cubic feet of fuel burned.
- Exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute and dry actual cubic feet per minute.
- All moisture concentrations shall be expressed in terms of percent corrected to 15 percent oxygen.
- For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of the AQMD, CARB, EPA and the CEC.

Verification: The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to both the SCAQMD and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the SCAQMD and CPM. The project owner shall notify the SCAQMD and CPM no later than 10 days prior to the proposed initial source test date and time.

AQ-8 The project owner shall conduct source testing of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the SCAQMD and the CPM for approval no later than 45 days prior to the proposed source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of SCAQMD Rule 304, and a description of all sampling and analytical procedures.
- Source testing for ammonia slip only shall be conducted quarterly for the first 12 months of operation and annually thereafter.
- NOx concentrations as determined by CEMS shall be simultaneously recorded during the ammonia test. If the NOx CEMS is inoperable, a test shall be conducted to determine the NOx emission by using SCAQMD Method 100.1 measured over a 60 minute time period.
- Source testing shall be conducted to determine the ammonia emissions from each gas turbine exhaust stack using SCAQMD Method 5.3 and 207.1 or U.S. EPA Method 17 measured over a 1 hour averaging period at the outlet of the SCR.
- The SCAQMD and CPM shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the SCAQMD and CPM within 45 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The test shall be conducted when the equipment is operating at 80 percent load or greater.
- If the turbine is not in operation during one quarter, then no testing is required during that quarter.
- All emission data is to be expressed in the following units:
    1. ppmv corrected to 15 percent oxygen,
    2. pounds per hour,
    3. pounds per million cubic feet of fuel burned.

<u>**Verification:**</u> The project owner shall submit the proposed protocol for the source tests 45 days prior to the proposed source test date to both the SCAQMD and CPM for approval. The project owner shall notify the SCAQMD and CPM no later than 7 days prior to the proposed source test date and time. The project owner shall submit source

test results no later than 45 days following the source test date to both the SCAQMD and CPM.

AQ-9 The project owner shall install and maintain a CEMS in each exhaust stack of the combustion turbine trains to measure the following parameters:

- NOx concentration in ppmv and CO concentration in ppmv.
- Concentrations shall be corrected to 15 percent oxygen on a dry basis.
- The CEMS will convert the actual CO concentrations to mass emission rates (lb/hr) and record the hourly emission rates on a continuous basis.
- The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period.
- The CEMS shall be installed and operated in accordance with an approved SCAQMD Rule 218 CEMS plan application and the requirements of Rule 2012.
- The CO CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine.
- The NOx CEMS shall be installed and operating no later than 12 months after initial start-up of the turbine.

During the interim period between the initial start-up and the provisional certification date of the CEMS, the project owner shall comply with the monitoring requirements of Rule 2012 (h)(2) and Rule 2012 (h)(3). Within two weeks of the turbine start-up date, the project owner shall provide written notification to the SCAQMD of the exact date of start-up.

<u>Verification:</u> Within 30 days of certification, the project owner shall notify the CPM of the completion of the certification process for the CEMS.

AQ-10 The project owner shall keep records in a manner approved by the SCAQMD for the following items:

- Natural Gas use after CEMS certification
- Natural Gas use during the commissioning period
- Natural Gas use after the commissioning period and prior to the CEMS certification.

<u>Verification:</u> The project owner shall submit to the CPM for approval all fuel usage records on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC10**.

AQ-11 The owner/operator shall determine the hourly ammonia slip emissions from each exhaust stack for each gas turbine individually via both the following formula:

SCAQMD Requirement

NH_3 (ppmv) = [a-b*(c*1.2)/1E6]*1E6/b

Where:

a = NH_3 injection rate (lb/hr) / 17(lb/lbmol),

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx across the SCR (ppmvd at 15 percent O_2)

The above described ammonia slip calculation procedure shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia for the District.

Energy Commission Requirement:

NH_3 (ppmv @ 15 percent O_2) = ((a-b*(c/1E6))*1E6/b)*d, where:

a = NH_3 injection rate (lb/hr)/17(lb/lbmol),

b = dry exhaust gas flow rate (lb/hr)/ (29(lb/lbmol), or

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx concentration ppmv corrected to 15 percent O_2 across catalyst, and

d = correction factor.

The correction factor shall be derived through compliance testing by comparing the measured and calculated ammonia slip. The correction factor shall be reviewed and approved by the CPM on at least an annual basis. The correction factor may rely on previous compliance source test results or other comparable analysis as the CPM finds the situation warrants. The above described ammonia slip calculation procedure shall be used for Energy Commission compliance determination for the ammonia slip limit as prescribed in Condition of Certification **AQ-4** and reported to the CPM on a quarterly basis as prescribed in Condition of Certification **AQ-SC10**.

An exceedance of the ammonia slip limit as demonstrated by the above Energy Commission formula shall not in and of itself constitute a violation of the limit. An exceedance of the ammonia slip limit shall not exceed 6 hours in duration. In the event of an exceedance of the ammonia slip limit exceeding 6 hours duration, the project owner shall notify the CPM within 72 hours of the occurrence. This notification must include, but is not limited to: the date and time of the exceedance, duration of the exceedance, estimated emissions as a result of the exceedance, the suspected cause of the exceedance and the corrective action taken or planned. Exceedances of the ammonia limit that are less than or equal to 6 hours in duration shall be noted in a specific section within the Quarterly Report (**AQ-SC10**). This section shall include, but is not limited to: the date and time of the exceedance, duration of the exceedance, and the estimated emissions as a result of the exceedance. Exceedances shall be deemed chronic if they total more than 10 percent of the operation for any single exhaust stack. Chronic exceedances must be investigated and redressed in a timely manner and in conjunction with the CPM through the cooperative development of a compliance plan. The compliance plan shall be developed to bring the project back into compliance first and foremost and shall secondly endeavor to do so in a feasible and timely manner, but shall not be limited in scope.

The owner/operator shall maintain compliance with the ammonia slip limit, redress exceedances of the ammonia slip limit in a timely manner, and avoid chronic exceedances of the ammonia slip limit. Exceedances shall be deemed a violation of the ammonia slip limit if they are not properly redressed as prescribed herein.

The owner/operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

Verification: The project owner shall include ammonia slip concentrations averaged on an hourly basis calculated via both protocols provided as part of the Quarterly Operational Report required in Condition of Certification **AQ-SC10**. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date. The project owner shall submit to the CPM for approval a proposed correction factor to be used in the Energy Commission formula at least once a year but not to exceed 180 days following the completion of the annual ammonia compliance source test. Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operational Report (**AQ-SC10**) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedance of the ammonia slip limit within 60 days of the above confirmation.

AQ-12 The operator shall install and maintain an ammonia injection flow meter and recorder to accurately indicate and record the ammonia injection flow rate being supplied to each turbine. The device or gauge shall be accurate to within plus or minus 5 percent and shall be calibrated once every twelve months. The ammonia injection system shall be placed in full operation as soon as the minimum temperature is reached. The minimum temperature is listed as 540 degrees F at the inlet to the SCR reactor.

Continuously recording is defined for this condition as at least once every hour and is based on the average of the continuous monitoring for that hour.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-13 The operator shall install and maintain a temperature gauge and recorder to accurately indicate and record the temperature in the exhaust at the inlet of the SCR reactor. The gauge shall be accurate to within plus or minus 5 percent and shall be calibrated once every twelve months. The catalyst temperature range shall remain between 740 degree F and 840 degree F. The catalyst temperature shall not exceed 840 degrees F. The temperature range requirement of this condition does not apply during startup operations of the turbine.

Continuously recording is defined for this condition as at least once every hour and is based on the average of the continuous monitoring for that hour.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-14 The operator shall install and maintain a pressure gauge and recorder to accurately indicate and record the pressure differential across the SCR catalyst bed in inches of water column. The gauge shall be accurate to within plus or minus 5 percent and shall be calibrated once every twelve months. The pressure drop across the catalyst shall not exceed 12 inches of water column during the start-up period.

Continuously recording is defined for this condition as at least once every month and is based on the average of the continuous monitoring for that month.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-15 The project owner shall limit the operating time of the firewater pump to no more than 199.99 hours per year. The firewater pump shall be equipped with a non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine. The firewater pump shall be equipped with a non-resettable totalizing fuel meter to accurately indicate the fuel usage of the engine. The firewater pump shall burn only diesel fuel that contains sulfur compounds less than or equal to 15 ppm by weight.

An engine operating log shall be kept in writing, listing the date of operation, the elapsed time, in hours, and the reason for operation. The log shall be maintained for a minimum of 5 years and made available to SCAQMD personnel and CPM upon request.

The project owner shall keep records in a manner approved by the Executive Officer; consisting of emergency use hours of operation, maintenance and testing hours, other operating hours (describe the reason for operation).

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate devices have been installed and are functioning properly. The project owner shall submit all dates of operation, elapsed time in hours, and the reason for each operation in the Quarterly Operations Report (**AQ-SC10**).

AQ-16 The project equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase. The project owner shall submit all such information to the CPM for approval.

To comply with this condition, the project owner, for the first year commissioning and operation, shall hold a minimum of:

- 35,839 lbs for each of Units 1-8, a total of 286,709 lbs.
- 77.25 lbs for the operation of the firewater pump.

A First Year Total of: 286,786 lbs NOx RTC.

To comply with this condition, the project owner, for the second year operation, shall hold a minimum of:

- 30,110 lbs for each of Units 1-8, a total of 240,881 lbs.
- 77.25 lbs for the operation of the firewater pump.

A Second Year Total of: 240,958 lbs NOx RTC.

Verification: The project owner shall submit evidence of sufficient RTCs to the CPM demonstrating compliance on an annual basis as part of the annual compliance report.

AQ-17 Deleted

AQ-18 Deleted

ACRONYMS

AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
CARB	California Air Resources Board
BACT	Best Available Control Technology
bhp	brake horse power
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CO	Carbon Monoxide
CPM	(CEC) Compliance Project Manager
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
gr	Grains (1 gr $\cong$ 0.0648 grams)
HRSG	Heat Recovery Steam Generator
ISCST3	Industrial Source Complex Short Term, version 3
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)
NH_3	Ammonia
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSR	New Source Review
PDOC	Preliminary Determination Of Compliance
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PRC	Priority Reserve Credit
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
RECLAIM	Regional Clean Air Incentives Market
RTC	RECLAIM Trading Credit
SCAQMD	South Coast Air Quality Management SCAQMD (also: District)
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SSAB	Salton Sea Air Basin
U.S. EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
CPV Sentinel	CPV Sentinel Energy Project

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Yannayon, US EPA, April 25, 2006 Personal telephone conversation.

AIR QUALITY APPENDIX AIR-1

Greenhouse Gas Emissions

Testimony of Steve Radis

SUMMARY OF CONCLUSIONS

The CPV Sentinel Energy Project (CPVS) is a proposed addition to the state's electricity system that would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. The proposed CPV Sentinel Energy Project (CPV Sentinel) would be a nominally rated 850 megawatt (MW) electrical generating facility that would encompass 37 acres of land situated within unincorporated Riverside County, California, adjacent to the Palm Springs northern city limits. The proposed project consists of eight natural gas-fired General Electric (GE) LMS100 combustion turbine generators (CTGs), each with an exhaust stack 13.5 feet in diameter and 90 feet tall. Each turbine generator would be operated up to a maximum of 2,628 hours per year with approximately 300 startup/shutdown cycles.

Its addition to the system would displace other less efficient, higher GHG-emitting generation and facilitate the integration of renewable resources. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those of other power plants that the project would displace, the addition of CPVS would contribute to a reduction of the California and overall Western Electricity Coordinating Council system GHG[2] emissions and GHG emission rate average.

While CPVS would emit GHG emissions, the relative efficiency of CPVS and the system build-out of renewable resources in California would result in a net cumulative reduction of energy and GHG emissions from new and existing fossil resources. Electricity is produced by operation of inter-connected generation resources. Operation of one power plant, like CPVS, affects all other power plants in the interconnected system. The operation of CPVS would affect the overall electricity system operation and GHG emissions in several ways:

- CPVS would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- The project would provide for peaking capacity needs identified by Southern California Edison (SCE), the Energy Commission, the California Public Utilities Commission (CPUC), and the California ISO for the Los Angeles Basin Local Capacity Requirements Area.

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[2] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from the fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

- CPVS would facilitate to some degree the replacement of high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's new Emissions Performance Standard.
- CPVS could facilitate to some extent the replacement of generation provided by aging and once-through cooling power plants.
- The CPVS would utilize the General Electric Power Systems (GE) LMS100's to allow for fast startup and ramping capability.
- The CPVS would help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

In February 2007, SCE executed a long-term contract for the capacity, energy, and ancillary services for five of the eight proposed CPV Sentinel units, to be delivered to SCE at Devers substation. In March 2008, SCE signed an additional long-term power purchase agreement for the remaining three CPV Sentinel units. The project will provide competitively priced electricity in the form of peaking capacity, energy, and ancillary services for sale to electric service providers to help meet expected electrical demand growth in Southern California, particularly in the rapidly growing portions of western Riverside County and the Coachella Valley.

Staff concludes that the short-term minor emission of greenhouse gases during construction that are necessary to create this new low GHG-emitting peaking resource would be sufficiently reduced by "best practices" and would, therefore, not be significant.

The project would meet the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants, should operating conditions at CPV Sentinel change in the future to a base load facility. The utility that enters into a contract with CPVS would seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed PPA, and any other conditions that dictate the operation of the CPVS. The CPS Sentinel meets the EPS of 0.500 metric tonnes CO_2 per megawatt-hour, with a rating of 0.451 metric tonnes CO_2 per megawatt-hour.

Staff notes that mandatory reporting of the GHG emissions provides the necessary information for the California Air Resources Board to develop greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project may be subject to additional reporting requirements and GHG reductions or trading requirements as these regulations are more fully developed and implemented. On a federal level 40 CFR 98 requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.

INTRODUCTION

GHG emissions are not criteria pollutants, but are discussed in the context of cumulative impacts. The State has demonstrated a clear willingness to address global climate change though research, adaptation[3], and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO2E) metric tonnes (MT) for ease of comparison.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of greenhouse gas emissions. Staff's analysis examines the project's compliance with these requirements.

GLOBAL CLIMATE CHANGE AND ELECTRICITY PRODUCTION

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps significantly) to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

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[3] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases or global climate change[4] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[5] To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by 2020. Electricity production facilities will be regulated by the ARB.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh)

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms (ARB 2006).

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[4] Global climate change is the result of greenhouse gases, or air emissions with global warming potentials, affecting the global energy balance, and thereby, climate of the planet. The terms greenhouse gases (GHG) and global climate change (GCC) gases are used interchangeably.

[5] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80 percent below 1990 levels by 2050.

The regulations must be effective by January 1, 2011 and mandatory compliance commences on January 1, 2012. The mandatory reporting requirements are effective for electric generating facilities over 1 megawatt (MW) capacity, and the due date for initial reports by existing facilities was June 1, 2009.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, were identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). The scoping plan approved by ARB in December 2008 builds upon the overall climate policies of the Climate Action Team report and shows the recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33 percent Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008).

It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40 percent reduction in GHG from the electricity sector, even though that sector currently only produces about 25 percent of the state's GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified regulation points should ARB decide that a multi-sector cap and trade system is warranted.

The Energy Commission's *2007 Integrated Energy Policy Report* (IEPR) also addressed climate change within the electricity, natural gas, and transportation sectors (CEC 2007). For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33 percent renewable portfolio standard. The Energy Commission's *2009 Integrated Energy Policy Report* continues to emphasize the importance of meeting greenhouse gas emissions reduction goals along with other important statewide issues such as backing out use of once-through cooling in coastal California power plants (CEC 2009d).

SB 1368,[6] enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission

[6] Public Utilities Code § 8340 et seq.

Performance Standard (EPS) of 0.500 metric tonnes CO_2 per megawatt-hour[7] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[8] If a project, instate or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that operate at a capacity factor higher than 60 percent. As a project applying for the flexibility to operate in peaking scenarios and not intended for use as a base load facility, CPVS would not have to meet the SB 1368 EPS. If CPVS enters into a contract to sell base load electricity in the future, CPVS would have to meet the SB 1368 EPS. In either case, as shown in **Greenhouse Gas Table 3**, GHG emissions from CPVS are below the limit of SB 1368 requirements.

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the Western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. And as with AB 32, the electricity sector has been a major focus of attention.

ELECTRICITY PROJECT GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation generally curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[9] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system mix. In this context, and because fossil-fueled resources produce GHG emissions, it is important to consider

[7] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[8] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

[9] See page CEC 2009b, page 95.

the role and necessity of also adding fossil-fuel resources such as CPVS. On October 8, 2008, the Energy Commission adopted an order initiating an informational (OII) proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA). A report prepared as a response to the GHG OII (CEC 2009a) defines five roles that gas-fired power plants are likely to fulfill in a high-renewables, low-GHG system (CEC 2009b, pp 93 and 94):

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

The Energy Commission staff-sponsored report reasonably assumes that non-renewable power plants added to the system would almost exclusively be natural gas-fueled. Nuclear, geothermal, and biomass plants are generally base load and not dispatchable. Solid fueled projects are also generally base load, not dispatchable, and carbon sequestration technologies needed to reduce the GHG emission rates to meet the EPS are not yet developed (CEC 2009b, p. 92). Further, California has almost no sites available to add highly dispatchable hydroelectric generation.

This analysis provides the staff's conclusions concerning greenhouse gas emissions for this siting case. Future power plant siting and amendment cases are likely to be reviewed with the benefit of new information and policy direction from the Energy Commission in response to the OII. This analysis recognizes that the "prudent use" of natural gas for electricity generation will serve to optimize the system (for integrating intermittent renewable generation and providing reliability), but, without further analysis and policy direction by the Commission to refine this general understanding, this analysis leaves the implications for optimizing the system to future cases (CEC 2009a).

PROJECT CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of CPVS would involve 18 months of activity. The project owner provided a GHG emission estimate for the entirety of the construction phase. The GHG emissions estimate, presented below in **Greenhouse Gas Table 2**, includes the total emissions for the 18 months of construction activity in terms of CO_2-equivalent.

PROJECT OPERATIONS

The proposed CPV Sentinel Energy Project (CPV Sentinel) would be a nominally rated 850 megawatt (MW) electrical generating facility that would encompass 37 acres of land situated within unincorporated Riverside County, California, adjacent to the Palm Springs northern city limits. The proposed project consists of eight natural gas-fired General Electric (GE) LMS100 combustion turbine generators (CTGs), each with an exhaust stack 13.5 feet in diameter and 90 feet tall. Each turbine generator would be operated up to a maximum of 2,628 hours per year with 300 startup/shutdown cycles.

Greenhouse Gas Table 2
CPVS, Estimated Potential Construction Greenhouse Gas Emissions

Construction Source [a]	Construction-Phase GHG Emissions (over 18 months) (MTCO2E) [b]
Site Construction	7,428
Laydown Area	1,064
Transmission Line	376
Gas Line	303
Construction Total	**9,170**

Source: CPVS 2009.

Notes:
a. Includes emissions from workers commuting to work site.
b. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

The primary sources of GHG would be the natural gas fired combustion turbines. There will also be a small amount of GHG emissions from the diesel fuel consumed in the emergency fire pump engine, and sulfur hexafluoride emissions from electrical component equipment.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. A small amount of SF_6 containing equipment will be required for this project, and the leakage of SF_6 and its CO_2 equivalent emissions have been estimated.

The proposed project would be permitted, on an annual basis, to emit approximately 960,504 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. The new CPVS facility would be more efficient than the existing power plants in the Los Angeles Basin Local Capacity Requirements Area, which has facilities with GHG performance ranging from 0.452 to 0.900 MTCO2/MWh. The proposed CPVS project would emit at 0.449 MTCO2/MWh, which would easily meet the SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh.

Greenhouse Gas Table 3
CPVS, Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions ($MTCO2E/yr$) [a]
Turbines	959,525
Emergency Fire Pump	1
Sulfur Hexafluoride (SF6) Leakage	978
Total Project GHG Emissions (MTCO2E/yr)	**960,504**
Estimated Annual Energy Output (MWh/yr) [b]	2,129,120
Estimated Annualized GHG Performance (MTCO2/MWh)	**0.449**
Estimated Annualized GHG Performance (MTCO2E/MWh)	**0.451**

Sources: CPVS 2007, 2009, including methane (CH_4) and nitrous oxide (N_2O); independent Energy Commission staff analysis for estimated energy output.

Notes:

a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

b. Annualized basis uses the project owner's assumed maximum permitted operating basis.

The proposed project would increase the available energy and capacity to the electricity system. The Los Angeles Basin Local Capacity Requirements Area would benefit from the incremental increase in energy and capacity provided by CPVS. As a project currently located inside a major load pocket, CPVS would be likely to provide local reliability support and could facilitate the retirement of other less-efficient power plants.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the construction and electricity sectors.

The impact of GHG emissions caused by this natural gas-fired facility is characterized by considering how the power plant would affect the overall electricity system. The integrated electricity system depends on fossil-fueled generation resources to provide energy and satisfy local capacity needs. As directed by the OII (CEC 2009a), staff is refining and implementing the concept of a “blueprint” that describes the long-term role of fossil-fueled power plants in California’s electricity system. The five separate roles that gas-fired power plants are most likely to fulfill in the future of a high-renewables, low-GHG system include: 1) Intermittent generation support; 2) Local capacity requirements; 3) Grid operations support; 4) Extreme load and system emergencies support; and 5) General energy support (CEC 2009b, p. 93). CPVS is analyzed here for its role in providing local capacity and generation and general energy support for expected generation retirements or replacements.

CONSTRUCTION IMPACTS

Staff believes that the small GHG emission increases from construction activities would not be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emission, such as limiting idling times and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

New, efficient, natural gas-fired generation promotes the state's efforts to improve GHG electrical generation efficiencies, therefore, reduces greenhouse gas emissions and the amount of natural gas used by electricity generation. As the *2007 Integrated Energy Policy Report* (CEC 2007, p. 184) noted:

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

Thus, in the context of the Energy Commission's *Integrated Energy Policy Report*, the CPVS's likely replacement of older existing plant capacity and higher GHG-emitting energy furthers the state's strategy to promote efficiency and reduce fuel use and GHG emissions. As stated in the 2009 *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* (CEC 2009b, p.20):

> When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.

Net GHG emissions for the integrated electric system will decline when new gas-fired power plants are added to: 1) permit the penetration of renewable generation to the 33 percent target; 2) improve the overall efficiency of the electric system; or 3) serve load growth or capacity needs more efficiently than the existing fleet (CEC 2009b, p. 98). CPVS, with its lower heat rate than the existing Los Angeles Basin Local Capacity Requirements Area power plants that it would displace and most other dispatchable gas-fired generation in the state, would be more efficient and lower GHG-emitting than the existing fleet, as shown in **Greenhouse Gas Table 4**.

Greenhouse Gas Table 4
Los Angeles Basin Local Capacity Requirements Area, Local Generation Heat Rates and 2008 Energy Outputs

Plant Name	Heat Rate (Btu/kWh)[a]	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Watson Cogeneration Co	8,512	3,017	0.452
Corona Cogen	9,430	274	0.500
Civic Center	9,447	467	0.501
San Gabriel	9,859	155	0.523
THUMS	10,123	379	0.537
ARCO Products Co	10,140	477	0.538
Harbor Cogeneration Co	10,649	44	0.565
Alamitos	10,782	2,533	0.572
Huntington Beach (AES)	10,927	1,536	0.580
El Segundo Power	11,044	508	0.586
Carson Cogeneration Co	11,513	540	0.611
Redondo Beach LLC (AES)	11,726	317	0.622
Total Energy Facilities	12,281	137	0.652
Torrance Refinery	12,370	161	0.656
Long Beach Generation LLC	15,323	27	0.813
UCLA Energy Systems Facility	15,418	206	0.818
BP West Coast Wilmington Calciner	16,953	201	0.900
CPV Sentinel Project (CPVS)	8,468	2,129	0.449

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER); with independent Energy Commission staff analysis for CPVS based on maximum utilization.

Notes:

a. Based on the Higher Heating Value or HHV of the fuel.

b. Peaker facilities

The Role of CPVS in Local Generation Displacement

The proposed CPVS project would have a net heat rate of 8,468 Btu/kWh[10] under normal operating conditions. The heat rate, energy output and GHG emissions of local generation resources near the CPVS are listed in **Greenhouse Gas Table 4**. Compared to most other new and existing units in the Los Angeles Basin Local Capacity Requirements Area, CPVS would be more efficient, and emit fewer GHG emissions per MWh of generation. Local generating units with the best (lowest) heat rate or lowest GHG performance factor generally operate more than other units with higher heat rates, as shown by the relative amount of energy (GWh) produced in 2008 from the local units. However, dispatch order can change, or deviate from economic or efficiency dispatch, in any one year or due to other concerns such as permit limits, contractual obligations, local reliability needs or emergencies. Because CPVS is inside the Los Angeles Basin

[10] Based on the High Heating Value (HHV) of the fuel(s) used. HHV is used for all heat rate and fuel conversions to GHG mass emissions that are discussed in this document.

Local Capacity Requirements Area, it would be able to provide capacity during most system operating conditions.

The Role of CPVS in the Renewable Goals/Load Growth

As California moves towards an increased reliance on renewable energy, the bulk of renewable generation available to and used in California in the near to intermediate future will be intermittent wind generation with some intermittent solar (CEC 2009b, p.3). To accommodate the increased variability in generation due to increasing renewable penetration, compounded by increasing load variability, control authorities such as the California Independent System Operator (CAISO) need increased flexibility from other generation resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources (CAISO 2007, p. 14).

CPVS would provide flexible, dispatchable and fast ramping[11] power that would not obstruct penetration of renewable energy. In general, combustion turbines can ramp up quickly. The LMS100 can be operated at loads as low as ten percent (10 MW), then ramped up quickly. When running at half load (50 MW), the machine can reach full load of nearly 100 MW in less than a minute. In addition, the LMS100 can go from a cold start to full load in ten minutes. This represents ramp rates of 10 to about 50 MW per minute.[12]

The amount of dispatchable fossil fuel generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased due to the planned intermittent resources needed to meet the 20 percent RPS (CAISO 2007, p.113); the 33 percent RPS will require even more dispatchable generation to integrate the renewables. However, this does not suggest the existing and new fossil fuel capacity will operate more in terms of total generation, but will need to operate more in a supplementary rather than base load role.

Greenhouse Gas Table 5 shows how the build-out of either the 20 percent or the 33 percent Renewable Portfolio Standards will affect generation from new and existing non-renewable resources. Should California reach its goal of meeting 33 percent of its retail demand in 2020 with renewable energy, non-renewable, most likely fossil-fueled, energy needs will fall by more than 36,500 GWh/year. In other words, all growth will need to come from renewable resources to achieve the 33 percent RPS, and some existing and new fossil units will generate less energy than they currently do, given the expected growth rate in retail sales.

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[11] The CAISO categorizes *fast-ramping* as a generator capable of going from lowest power to highest in under 20 minutes, or greater than 10 MW per minute.

[12] Of the 2,821 MW of thermal resources providing Ancillary Services to the CAISO, most (2,441 MW) have ramp rates between 10 and 31 MW/min. The bulk of the resources providing Ancillary Services with ramp rates greater than 10 MW/min (7,141 MW) are hydroelectric facilities (ISO 2007).

Greenhouse Gas Table 5
Estimated Changes in Non-Renewable Energy Potentially Needed to Meet California Loads, 2008-2020

California Electricity Supply	Annual GWh	
Statewide Retail Sales, 2008, estimated [a]	264,794	
Statewide Retail Sales, 2020, forecast [a]	289,697	
Growth in Retail Sales, 2008-20	24,903	
Growth in Net Energy for Load [b]	29,840	
California Renewable Electricity	**GWh @ 20% RPS**	**GWh @ 33% RPS**
Renewable Energy Requirements, 2020 [c]	57,939	95,600
Current Renewable Energy, 2008	29,174	
Change in Renewable Energy-2008 to 2020 [c]	28,765	66,426
Resulting Change in Non-Renewable Energy	176	(36,586)

Source: Energy Commission staff 2010.

Notes:

a. 2009 IEPR Demand Forecast, Form 1.1c. Excludes pumping loads for entities that do not have an RPS.

b. 2009 IEPR Demand Forecast, Form 1.5a..

c. RPS requirements are a percentage of retail sales.

These assumptions are conservative in that the forecasted growth in retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the current retail sales forecast.[13] Energy Commission staff estimates that as much as 18,000 GWh of additional savings due to uncommitted energy efficiency programs may be forthcoming.[14] This would reduce non-renewable energy needs by a further 12,000 GWh given a 33 percent RPS.

The Role of CPVS in Retirements/Replacements

CPVS would be capable of annually providing 2,129 GWh of natural gas-fired energy at permitted levels to replace resources that are or will likely be precluded from serving California loads. State policies, including GHG goals, are discouraging or prohibiting new contracts and new investments in high GHG-emitting, such as coal-fired generation, generation that relies on water for once-through cooling, and aging power plants (CEC 2007). Some of the existing plants that are likely to require significant

[13] Energy efficiency savings are already represented in the current Energy Commission demand forecast adopted December 2009 (CEC 2009c).

[14] See *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (CEC-200-2010-001-D, January, 2010), page 2. Table 1 indicates that additional conservation for the three investor-owned utilities may be as high as 14,374 GWh. Increasing this value by 25 percent to account for the state's publicly-owned utilities yields a total reduction of 17,967 GWh.

capital investments to continue operation in light of these policies may be unlikely to undertake the investments and will retire or be replaced.

Replacement of High GHG-Emitting Generation

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, more than 18,000 GWh of energy procured by California utilities under these contracts will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 6**.

Greenhouse Gas Table 6
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	Facility [a]	Contract Expiration	Annual GWh Delivered to CA
PG&E, SCE	Misc In-state Qual. Facilities [a]	2009-2019	4,086
LADWP	Intermountain	2009-2013	3,163 [b]
City of Riverside	Bonanza, Hunter	2010	385
Department of Water Resources	Reid Gardner	2013 [c]	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners	2016	4,920
Turlock Irrigation District	Boardman	2018	370
LADWP	Navajo	2019	3,832
		TOTAL	18,522

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.

Notes:

a. All facilities are located out-of-state except for the Miscellaneous In-state Qualifying Facilities.

b. Estimated annual reduction in energy provided to LADWP by Utah utilities from their entitlement by 2013.

c. Contract not subject to Emission Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.

This represents almost half of the energy associated with California utility contracts with coal-fired resources that will expire by 2030. If the State enacts a carbon adder[15], all the coal contracts (including those in **Greenhouse Gas Table 6**, which expire by 2020, and other contracts that expire beyond 2020 and are not shown in the table) may be retired at an accelerated rate as coal-fired energy becomes uncompetitive due to the carbon adder or the capital needed to capture and sequester the carbon emissions. Also shown are the approximate 500 MW of in-state coal and petroleum coke-fired capacity that may not be able to contract with California utilities for baseload energy due to the SB1368 Emission Performance Standard. As these contracts expire, new and existing

[15] A carbon adder or carbon tax is a specific value added to the cost of a project per ton of associated carbon or carbon dioxide emissions. Because it is based on, but not limited to, actual operations and emission and can be trued up at year end, it is considered a simple mechanism to assign environmental costs to a project.

generation resources will replace the lost energy and capacity. Some will come from renewable generation; some will come from new and existing natural gas fired generation. All will emit significantly less GHG than the coal and petroleum coke-fired generation, which average about 1.0 MTCO2/MWh without carbon capture and sequestration, or almost three times more than a natural gas-fired turbine project like CPVS, resulting in a significant net reduction in GHG emissions from the California electricity sector.

Retirement of Generation Using Once-Through Cooling

New, dispatchable resources like CPVS would also be required to provide generation capacity (that is, the ability to meet fluctuating, intermittent electricity loads) in the likely event that facilities utilizing once-through cooling (OTC) are retired. The State Water Resources Control Board (SWRCB) has proposed significant changes to OTC units, which would likely require retrofit, retirement, or significant curtailment of dozens of generating units. In 2008, these units collectively produced about 58,000 GWh. While those OTC facilities owned and operated by utilities and recently-built combined cycles may well install dry or wet cooling towers, it is unlikely that the aging, merchant plants will do so. Most of these units operate at low capacity factors, suggesting a limited ability to compete in the current electricity market. Although the timing would be uncertain, new resources would out-compete aging plants and would displace the energy provided by OTC facilities and likely accelerate their retirements.

Any additional costs associated with complying with the SWRCB regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced. These units constitute over 15,000 MW of merchant capacity and 17,800 GWh of merchant energy. Of this, much but not all of the capacity and energy are in local reliability areas, requiring a large share of replacement capacity – absent transmission upgrades – to locations in the same local reliability area. **Greenhouse Gas Table 7** provides a summary of the statewide utility and merchant energy supplies affected by the OTC regulations.

New generation resources that can either provide local support or energy will emit significantly less GHGs than existing OTC natural gas generation. Existing aging and OTC natural gas generation average 0.6 to 0.7 MTCO2/MWh, which is less efficient, higher GHG emitting, than a new natural gas-fired turbine project like CPVS. When a project can provide energy and capacity, given its location, it can provide a significant net reduction in GHG emissions from the California electricity sector. A project located in a coastal load pocket, like the Los Angeles Local Reliability Area, would more likely provide local reliability support as well as facilitate the retirement of aging and/or OTC power plants.

Greenhouse Gas Table 7
Aging and Once-Through Cooling Units: 2008 Capacity and Energy Output [a]

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2008 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	17,091	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	15,392	Nuclear
Broadway 3 [b]	Utility	L.A. Basin	Yes	75	90	0.648
El Centro 3, 4 [b]	Utility	None	Yes	132	238	0.814
Grayson 3-5 [b]	Utility	LADWP	Yes	108	150	0.799
Grayson CC [b]	Utility	LADWP	Yes	130	27	0.896
Harbor CC	Utility	LADWP	No	227	203	0.509
Haynes 1, 2, 5, 6	Utility	LADWP	Yes	1,046	1,529	0.578
Haynes CC	Utility	LADWP	No	560	3,423	0.376
Humboldt Bay 1, 2 [a]	Utility	Humboldt	Yes	107	507	0.683
Olive 1, 2 [b]	Utility	LADWP	Yes	110	11	1.008
Scattergood 1-3	Utility	LADWP	Yes	803	1,327	0.618
Utility-Owned				7,776	39,988	0.693
Alamitos 1 – 6	Merchant	L.A. Basin	Yes	1,970	2,533	0.661
Contra Costa 6, 7	Merchant	S.F. Bay Area	Yes	680	160	0.615
Coolwater 1-4 [b]	Merchant	None	Yes	727	576	0.633
El Segundo 3, 4	Merchant	L.A. Basin	Yes	670	508	0.576
Encina 1-5	Merchant	San Diego	Yes	951	997	0.674
Etiwanda 3, 4 [b]	Merchant	L.A. Basin	Yes	666	848	0.631
Huntington Beach 1, 2	Merchant	L.A. Basin	Yes	430	916	0.591
Huntington Beach 3, 4	Merchant	L.A. Basin	No	450	620	0.563
Mandalay 1, 2	Merchant	Ventura	Yes	436	597	0.528
Morro Bay 3, 4	Merchant	None	Yes	600	83	0.524
Moss Landing 6, 7	Merchant	None	Yes	1,404	1,375	0.661
Moss Landing 1, 2	Merchant	None	No	1,080	5,791	0.378
Ormond Beach 1, 2	Merchant	Ventura	Yes	1,612	783	0.573
Pittsburg 5-7	Merchant	S.F.Bay	Yes	1,332	180	0.673
Potrero 3	Merchant	S.F.Bay	Yes	207	530	0.587
Redondo Beach 5-8	Merchant	L.A. Basin	Yes	1,343	317	0.810
South Bay 1-4	Merchant	San Diego	Yes	696	1,015	0.611
Merchant-Owned				15,254	17,828	0.605
Total In-State OTC				23,030	57,817	

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.

Notes:

a. OTC Humboldt Bay Units 1 and 2 are included in this list. They must retire in 2010 when the new Humboldt Bay Generating Station (not ocean-cooled), currently under construction, enters commercial operation.

b. Units are aging but are not OTC.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts" (CEQA Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts” (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LORS

Ultimately, ARB’s AB 32 regulations may address both the degree of electricity generation sector emissions reductions (through cap-and-trade), and the method by which those reductions will be achieved (e.g., through command-and-control). However, the exact approach is currently under development. That regulatory approach may address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Commission, but also the older, higher-emitting facilities not subject to Energy Commission jurisdiction. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the entire electricity sector than one that merely relies on displacing out-of-state coal plants (“leakage”) or older, “dirtier” facilities.

The Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified the regulation points should ARB decide that a multi-sector cap-and-trade system is warranted. As ARB codifies improved GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness.

The project would be subject to ARB’s mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB’s mandatory GHG emissions reporting requirements do not indicate whether the project, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any future AB 32 requirements that could be enacted in the next few years. Since this power project would be permitted for more than a 60 percent annual capacity factor, the project is subject to the requirements of

SB 1368 and the current Emission Performance Standard. CPVS's GHG emission performance would be well below the SB 1368 EPS. Source testing will be conducted to demonstrate compliance with the GHG performance standards.

NOTEWORTHY PUBLIC BENEFITS

Electricity is produced by operation of inter-connected generation resources and by knowing the fuel used by the generation sector, the resulting GHG emissions can be known. Operation of one power plant, like CPVS, affects all other power plants in the interconnected system. The operation of CPVS facility will have an impact upon system operation and GHG emissions in several ways:

- CPVS would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- CPVS would displace some less efficient local generation in the dispatch order of gas-fired facilities that are required to provide local electricity reliability in the Los Angeles Basin Local Capacity Requirements Area.
- CPVS would facilitate to some degree the replacement of high GHG-emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet to the State's new Emission Performance Standard.
- CPVS could facilitate to some extent the replacement of generation provided by aging and use once-through cooling power plants.
- The CPVS would utilize the General Electric Power Systems (GE) LMS100's to allow for fast startup and ramping capability.
- The CPVS would help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

The project would likely lead to a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. Moreover, it would be consistent with AB 32 goals.

The energy displaced by the CPVS project would result in a reduction in GHG emissions from the electricity system. In other system roles, as described in **Greenhouse Gas Table 8**, CPVS would minimize its GHG impacts by addressing nearly all of the expected future roles for gas-fired generation, in a high-renewables, low-GHG system.

Greenhouse Gas Table 8
CPVS, Summary of Role in Providing Energy and Capacity Resources

Services Provided by Generating Resources	Discussion, CPVS
Integration of Renewable Energy	• Would provide fast startup capability (within 2 hours). • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves, and energy when renewable resources are unavailable.
Local Generation Displacement	• Would be able to satisfy/partially satisfy local capacity area (LCA) resource requirements. • Would provide voltage support. • *Would not* provide black start capability.
Ancillary Services, Grid System, and Emergency Support	• Would provide fast startup capability (within 2 hours). • *Would not* have low minimum load levels. • Would provide rapid ramping capability. • Would have ability to provide regulation and reserves. • *Would not* provide black start capability.
General Energy Support	• Would provide general energy support. • Could facilitate some retirements and replacements • Would provide cost-competitive energy. • Would be able to help a load-serving entity (LSE) meet resource adequacy (RA) requirements.

Source: Energy Commission staff; based on: Expected Roles for Gas-Fired Generation (CEC2009b, p. 7).

CONCLUSIONS

CPVS, as an addition to the California electricity system, would be an efficient, new, dispatchable natural gas-fired turbine power plant that would cause GHG emissions while generating electricity for California consumers. AB 32 emphasizes that GHG emission reductions must be “big picture” reductions that do not lead to “leakage” of such reductions to other states or countries. The project’s GHG emissions per MWh would be lower than those of other power plants and peaking projects that the project would replace and, thus, would contribute to continued improvement of the California and overall Western Electricity Coordinating Council system greenhouse gas (GHG) emissions and GHG emission rate average.

The project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state’s power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. CPVS would also provide other potential GHG benefits by addressing nearly all of the expected future roles for gas-fired generation, in a high-renewables, low-GHG system.

Staff notes that mandatory reporting of GHG emissions per Air Resources Board greenhouse gas regulations would occur, and this would enable the ARB to gather the information needed to regulate CPVS in trading markets if required by the regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations are more fully developed and implemented.

Staff does not believe that the minor GHG emission increases from construction activities would be significant for several reasons. First, the period of construction would be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures or best practices, that staff recommends such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards, would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff concludes that the minor short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

The project would meet the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants, should operating conditions at CPV Sentinel change in the future to a base load facility. The utility that enters into a contract with CPVS would seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed PPA, and any other conditions that dictate the operation of the CPVS. The CPS Sentinel meets the EPS of 0.500 metric tonnes CO_2 per megawatt-hour, with a rating of 0.451 metric tonnes CO_2 -equivalent per megawatt-hour.

PROPOSED CONDITIONS OF CERTIFICATION

No Conditions of Certification related to greenhouse gas emissions are proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.) and/or future GHG regulations formulated by the ARB, such as GHG emissions cap and trade markets.

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WITNESS QUALIFICATION AND DECLARATION

DECLARATION OF
Steven R. Radis

I**, Steven R. Radis** declare as follows:

1. I am presently employed as a consultant to the California Energy Commission in the **Environmental Protection Office** of the **Energy Facilities Siting Division**.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Air Quality**, for the **CPV Sentinel Project** based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: April 15, 2010 Signed: Steven R Radis

At: Ventura, California

Steven R. Radis

Mr. Radis is a Principal with MRS. Before joining MRS, he was a Principal in Arthur D. Little, Inc.'s Environmental Health & Safety Practice located in the Santa Barbara and Ventura, California offices. His expertise includes meteorological modeling and analysis, physical oceanographic modeling and analysis, consequence and risk analysis, fire and explosion dynamics, hazard evaluation, external events analysis, fault tree analysis, and model development. Mr. Radis has worked on a wide variety of studies for utilities, commercial, and government clients involving meteorological modeling, quantitative risk assessments, health risk assessments, consequence analysis, risk management, air quality modeling (inert/photochemical pollutants, toxic air contaminants), and Environmental Impact Reports (EIR)/Statements (EIS) prepared in compliance with the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA). His experience includes the following:

- Mr. Radis has participated on power plant siting projects before the California Energy Commission in a variety of roles. He is currently assisting the CEC on the GWF Tracy Combined Cycle Power Plant, City of Palmdale Hybrid Power Plant, Watson Cogeneration Steam and Electric Reliability, and the Kings River Conservation District Community Power Plant projects. Mr. Radis also participated as an intervener on the Metcalf Energy Center and Potrero Unit 7 siting cases. Mr. Radis has also represented applicants on the Occidental Elk Hills project, and several siting cases in the 1980's for Southern California Edison.
- Mr. Radis completed a safety and vulnerability analysis of the Diablo Canyon Power Plant (DCPP) and the San Onofre Nuclear Generating Station (SONGS) Steam Generator Replacement Projects for the California Public Utilities Commission. The EIR analyses evaluated a range of equipment and operational failure modes and quantitatively evaluated the associated radiological consequences of core damage accidents and releases. Failure modes, release mechanisms and consequences associated with terrorist attacks were also evaluated.
- For the County of San Luis Obispo, Mr. Radis completed a safety and vulnerability analysis of the Diablo Canyon Power Plant (DCPP) Independent Spent Fuel Storage Installation (ISFSI). The EIR analysis evaluated a range of equipment and operational failure modes and quantitatively evaluated the associated radiological consequences of spent fuel pool and dry cask storage accidental releases. Failure modes, release mechanisms and consequences associated with terrorist attacks were also evaluated.
- Mr. Radis was the project Manager and Public Safety coordinator for the Venoco Ellwood Marine Terminal Lease Renewal Project EIR that was recently prepared for the California State Lands Commission. This is the last marine oil terminal in Santa Barbara County and the continuing operation of the terminal is raising a lot of public opposition. Critical environmental issues include the increased risk of an accidental release of oil and its impact on marine and terrestrial water quality and biological resources, recreation, land use, and visual resources.
- Mr. Radis prepared two sections of the Plains All American Crude Oil Marine Terminal SEIS/EIR, the project that includes construction of a marine terminal on

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Pier 400 in the Port of Los Angeles. Marine Vessel Transportation and System Safety/Risk of Upset. The Marine Vessel Transportation analysis considers the specific type and number of vessels that currently visit the Port and pass by Pier 400, and evaluates the number and characteristics of tankers that would be calling at the new Pier 400 marine terminal after project implementation.

- For the California Coastal Commission, Mr. Radis provided technical assistance in the reviews of the BHP Billiton Liquefied Natural Gas (LNG) Cabrillo Port Project and the Port of Long Beach Sound Energy Solutions (SES) Long Beach LNG Project. The review of the proposed projects is focused on the adequacy and completeness of risk analysis, especially in terms of the safety review requirements of 49 CFR 193 Subpart B and NFPA Design Standard 59A. Mr. Radis is also acting as a technical advisor to CCC staff on risk analysis, vapor dispersion modeling, etc., as well as identifying deficiencies, if any, in the analysis or recommended mitigation measures. Mr. Radis is also currently providing technical assistance to the California Coastal Commission on the OceanWay and Clearwater LNG projects.
- Mr. Radis managed the preparation of an Environmental Impact Report for the Nacimiento Water Project. The EIR that evaluated environmental impacts associated with construction and operation of a 65-mile water pipeline and associated facilities in San Luis Obispo County. The pipeline would draw water from Nacimiento Reservoir and deliver it to various purveyors in the County. The pipeline would cross numerous jurisdictions and would affect a number of landowners and agencies. The proposed project included two equal options: (1) Raw Water Option that entailed construction of the pipeline and facilities that would deliver raw water to the purveyors; and (2) Treated Water Option that also entailed construction of a water treatment plant; in this case, potable water would be delivered to the purveyors. This EIR contained more than 800 pages, not including the Executive Summary and technical appendices. Over 140 mitigation measures were developed to lessen impacts from the proposed project.
- Mr. Radis was a Project Manager on the Point Pedernales Project Supplemental EIR that was prepared for Santa Barbara County. Mr. Radis was also the Principal Investigator for the Air Quality and Risk-of-Upset Project portions of the Supplemental EIR.
- Mr. Radis conducted system safety and reliability studies for several oil and gas projects for Santa Barbara County. These studies included hazard identification, external event and offsite consequence analyses. Facilities included oil and gas processing plants, offshore platforms, onshore production facilities, as well as sour gas and crude oil pipelines. Quantitative Risk Analyses (QRA) were prepared for several of the projects.
- As part of an EIR/EIS for the Unocal Avila Beach Cleanup Project, Mr. Radis served as the Project Manager for San Luis Obispo County, California Regional Water Quality Control Board, and the U.S. Army Corps of Engineers. The EIR/EIS included the evaluation of site contamination and a variety of cleanup strategies, including air

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sparging/bioventing, solidification/ stabilization, solvent flooding, steam stripping, excavation, and thermal desorption. Leaking Unocal Marine Terminal pipelines had resulted in approximately 400,000 gallons of petroleum hydrocarbon contamination beneath the town of Avila Beach and the adjacent beach and intertidal zone. San Luis Obispo County certified the EIR/EIS, and Mr. Radis assisted the Regional Water Quality Control Board in establishing cleanup levels for the site.

- For the Center for Chemical Process Safety (CCPS) of the American Institute of Chemical Engineers (AIChE), Mr. Radis co-authored a book entitled *Guidelines for Postrelease Mitigation Technology in the Chemical Process Industry*. As part of this effort, Mr. Radis quantitatively evaluated the effectiveness of a variety of hazardous chemical mitigation technologies.
- For a Texas-based law firm, Mr. Radis prepared an analysis of external events and provided expert testimony to the Texas Water Commission related to the safety of a hazardous waste disposal facility proposed for the Houston Ship Channel. This study included a review of past external events in the region and centered on hurricane, tornado, and storm surge hazards. The study required the development of a wind field model to simulate hurricanes passing over the site and to estimate potential maximum wind speeds and wind load on the proposed equipment, as well as projected changes in ship channel water levels.
- For a large Southern California utility, Mr. Radis evaluated the feasibility and system safety of converting a fuel oil pipeline distribution network into a regional crude oil and petroleum product storage and distribution system. An analysis of safety and environmental issues was prepared for the CPUC and the South Coast Air Quality Management District. Both agencies approved the conversion project, which is now operating at full capacity. An expansion of the pipeline system was evaluated to increase overall system pipeline throughput capacity, as well as to accommodate unit train and VLCC tanker deliveries.
- Mr. Radis has been involved in the preparation of EIR/EISs for a wide variety of facilities including power generating facilities (coal, fuel oil, natural gas, geothermal, hazardous waste), hazardous waste disposal facilities (chemical and nuclear), crude oil and natural gas transmission pipelines and distribution networks, oil and gas development projects, and military development or conversion projects. Mr. Radis has managed a majority of these projects and was also responsible for the system safety, public health, and air quality issue areas.
- For four Local Emergency Planning Committees (LEPCs) in Alaska, Mr. Radis developed emergency response planning procedures through the preparation of a comprehensive regional hazard and risk analysis.
- For a large engineering company, Mr. Radis prepared a quantitative risk assessment for a LNG marine terminal and power plant project in Puerto Rico. The project included conducting a hazard assessment, fault tree analysis, consequence analysis,

Steven R. Radis (continued)

and quantitative risk analysis. An analysis of external events that could potentially affect the proposed facility was also conducted.

- Mr. Radis has worked on the development of several models, including the development or revisions to several accidental release models, an oil spill model, a multi-component pool model, atmospheric diffusion models, an integrated human exposure and health risk assessment model, and several meteorological models.

Mr. Radis earned his M.A. and B.A degrees in Climatology from California State University, Northridge. He is a member of the American Meteorological Society, and the Air and Waste Management Association.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE
CPV SENTINEL ENERGY PROJECT
BY THE CPV SENTINEL, L.L.C

DOCKET NO. 07-AFC-3

PROOF OF SERVICE
(Revised 3/24/2010)

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DECLARATION OF SERVICE

I, Maria Santourdjian, declare that on April 15, 2010, I served and filed a copy of the attached Final Staff Assessment Air Quality Addendum for CPV Sentinel Project (07-AFC-3). The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: [http://www.energy.ca.gov/sitingcases/sentinel/index.html]

The documents has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

For service to all other parties:

__x__ sent electronically to all email addresses on the Proof of Service list;

__x__ by personal delivery;

__x__ by delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "email preferred."

AND

For filing with the Energy Commission:

__x__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (preferred method);

OR

_____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 07-AFC-3
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Originally Signed by
Maria Santourdjian