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5.1 AIR QUALITY

5.1.1 Introduction

This Application for Certification (AFC) for the Rio Mesa Solar Electric Generating Facility (Rio Mesa SEGF or Project) has been prepared in accordance with the California Energy Commission's (CEC) Power Plant Site Certification Regulations (CEC-140-2008-001-REV1, current as of July 2008). In addition, this AFC includes elements necessary for the United States (U.S.) Bureau of Land Management (BLM) to permit the Project through the National Environmental Policy Act (NEPA). The ―Applicant" for purposes of this AFC comprises Rio Mesa Solar I, LLC, Rio Mesa Solar II, LLC, and Rio Mesa Solar III, LLC, owners of the three separate solar plants and certain shared facilities being proposed. These three Delaware limited liability companies will hold equal one-third shares in the ownership of shared facilities and will separately own their respective plants. They are wholly owned by Rio Mesa Solar Holdings, LLC (a Delaware limited liability company) which is in turn wholly owned by BrightSource Energy, Inc. (BrightSource) a Delaware corporation and the ultimate parent company. The Applicant will use BrightSource's solar thermal technology for the Rio Mesa SEGF.

The proposed project site is situated on the Palo Verde Mesa in Riverside County, California, 13 miles southwest of the City of Blythe, and is located partially on private land and partially on public land administered by BLM. The project will include three solar concentrating thermal power plants and a shared common area to include shared systems. The first plant, a 250 megawatt (MW) (nominal) facility known as Rio Mesa I, will be constructed at the south end of the project and owned by Rio Mesa Solar I, LLC. The second plant, another 250 MW (nominal) facility known as Rio Mesa II, will be located in the central portion of the project site and owned by Rio Mesa Solar II, LLC. Rio Mesa III, a third 250 MW (nominal) facility, will be constructed in the northern portion of the project site and owned by Rio Mesa Solar III, LLC. These three plants will be connected via a common overhead 220 kilovolt (kV) generator tie-line (gen-tie line) to the Southern California Edison (SCE) Colorado River Substation (CRS) approximately 9.7 miles to the north.

Each plant will utilize a solar power boiler (referred to as a solar receiver steam generator or SRSG), located on top of a dedicated concrete tower, and solar field based on proprietary heliostat mirror technology developed by BrightSource. The reflecting area of an individual heliostat (which includes two mirrors) is about 19 square meters (205 square feet [sq. ft.]). The heliostat (mirror) fields will focus solar energy onto the SRSG which converts the solar energy to superheated steam. In each plant, a Rankine cycle non-reheat steam turbine receiving this superheated steam will be directly connected to a rotating generator that generates and pushes the electricity onto the transmission system steam. Each plant will generate electricity using solar energy as its primary fuel source. However, auxiliary boilers will be used to operate in parallel with the solar field during partial load conditions and occasionally in the afternoon when power is needed after the solar energy has diminished to a level that no longer will support solar generation of electricity. These auxiliary boilers will also assist with daily start-up of the power generation equipment and night time preservation.

This section of the AFC describes existing air quality conditions; maximum potential impacts from the project; compliance with applicable laws, ordinances, regulations and standards; and mitigation measures that keep project impacts below applicable thresholds of significance. The methodology and results of the

air quality analysis used to assess potential impacts are also presented. The analysis has been conducted according to the CEC power plant siting requirements and also addresses Mojave Desert Air Quality Management District (MDAQMD) air permitting requirements.

- Section 5.1.2, Laws, Ordinances, Regulations, and Standards, describes applicable laws, ordinances, regulations, and standards (LORS) pertaining to air quality aspects of the project.
- Section 5.1.3, Affected Environment, describes elements of the local environment that are relevant to evaluation of the Project‘s potential air quality effects. These include topography, climate, and existing air quality. The most representative meteorological data—including wind speed and direction, temperature, relative humidity, and precipitation—and the most representative recent measurements of ambient air pollutant concentrations in the Project vicinity are summarized. Air pollutants emitted by the Project may travel in the atmosphere over long distances, but for practical purposes, the Project air quality study area can be considered to be the eastern section of Riverside County.
- Section 5.1.4, Environmental Analysis, evaluates the maximum potential air quality effects due to the Project‘s emissions of criteria pollutants [nitrogen oxides (NOx), carbon monoxide (CO), sulfur oxides (SOx), volatile organic compounds (VOC), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$)]. Estimated emissions of these pollutants are presented for the construction phase of the Project, as well as for operation of the installed equipment. Because of the nature of the Project, operational emissions will be small; however, a modeling analysis conducted for operational emissions of nitrogen dioxide (NO_2), CO, sulfur dioxide (SO_2), and particulate matter ($PM_{2.5}$ and PM_{10}) is presented. The results show that the Project will neither cause an exceedance of the California and/or National Ambient Air Quality Standards (CAAQS and NAAQS), nor contribute significantly to an existing exceedance.
- Section 5.1.5, Cumulative Air Quality Impacts, addresses the cumulative effects of the Project emissions with other potential new sources of air pollution in the area around the Rio Mesa SEGF.
- Section 5.1.6, Consistency with Laws, Ordinances, Regulations, and Standards, describes all applicable LORS.
- Section 5.1.7, Mitigation Measures, describes the emission mitigation measures proposed for Project construction. Emission sources associated with the operational Project will be limited to exhaust from vehicles working on the site in support of solar collector cleaning and facility maintenance, in addition to diesel internal combustion engine drivers for one emergency fire water pump and one backup generator. These engines will only be tested periodically to ensure their operability in the event of a fire or emergency loss of grid power.
- Section 5.1.8, Involved Agencies and Agency Contacts, lists the agency personnel contacted during preparation of the air quality assessment.
- Section 5.1.9, Permits Required and Permit Schedule
- Section 5.1.10, References, lists the references used to conduct the air quality assessment.

The focus of this assessment of the Project's potential air quality effects is on criteria pollutants, i.e., those pollutants for which federal and California ambient standards have been promulgated. Information on the Project's emissions of toxic air contaminants and the associated health risks is presented in Section 5.16, Public Health and Safety.

5.1.2 Laws, Ordinance, Regulations and Standards

Each level of government—federal, state, and local—has adopted specific regulations that regulate emissions from stationary sources, several of which are applicable to this project. Each of these regulatory programs is discussed in the following sections. Table 5.1-1 summarizes the applicable laws, ordinances, regulations and standards (LORS) related to air quality.

Table 5.1-1
Laws, Ordinances, Regulations and Standards (LORS)

LORS	Summary	AFC Section Explaining Conformance
Federal		
National Environmental Policy Act (NEPA) of 1969	NEPA establishes a public, interdisciplinary framework for federal decision-making and ensures that Federal agencies take environmental factors into account when considering federal actions.	Section 5.1.2.1
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC §7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (Prevention of Significant Deterioration [PSD] Program)	Requires PSD review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than National Ambient Air Qualtiy Standards (NAAQS).	Section 5.1.2.1
CAA §171-193, 42 USC §7501 et seq. (New Source Review [NSR])	Requires NSR facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS.	Section 5.1.2.1
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NO_x and SO_2 emissions.	Section 5.1.2.1
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	Section 5.1.2.1
CAA §111, 42 USC §7411, 40 CFR Part 60 (New Source Performance Standards [NSPS])	Establishes national standards of performance for new stationary sources.	Section 5.1.2.1

Table 5.1-1
Laws, Ordinances, Regulations and Standards (LORS)

LORS	Summary	AFC Section Explaining Conformance
CAA §112, 42 USC §7412, 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants [NESHAP])	Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by United States Environmnetal Protection Agency [EPA] as causing or contributing to the adverse health effects of air pollution, but for which NAAQS have not been established) from major sources of HAPs in specific source categories.	Section 5.1.2.1
State		
Warren-Alquist State Energy Resources Conservation and Development Act, California Public Resources Code, §§ 25000, et seq.	Gives the California Energy Commission (CEC) licensing authority in lieu of state, regional, and local permits and requirements.	Section 5.1.2.2
California Environmental Quality Act (CEQA) California Public Resources Code, Division 13, §§ 21000-21177, as amended 2010.	Requires all agencies of State government that regulate activities of private individuals, corporations, and public agencies, which are found to affect the quality of the environment, shall regulate such activities so that major consideration is given to preventing environmental damage.	Section 5.1.2.2
HSC §44300-44384; California Code of Regulations (CCR) §93300-93347 (Toxic "Hot Spots" Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	Section 5.1.2.2
California Public Resources Code §25523(a); 20 CCR §§1752, 2300-2309 (CEC & California Air Resources Board [CARB] Memorandum of Understanding)	Requires that CEC's decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	Section 5.1.2.2
17 CCR § 93115 (Airbone Toxic Control Measure [ATCM] for Stationary Compression Ignition Engines)	Establishes emission and operational limits for Diesel-fueled stationary compression ignition engines.	Section 5.1.2.2
Local		
Mojave Desert Air Quality Management District (MDAQMD) Regulation XIII (New Source Review)	NSR: Requires that pre-construction review be conducted for all proposed new or modified sources of air pollution, including best available control technology (BACT), emissions offsets, and air quality impact analysis.	Section 5.1.2.3
MDAQMD Rule 1320 (New Source Review for Toxic Air Contaminants)	Requires that pre-construction review be conducted for all proposed new or modified sources of toxic air contaminants.	Section 5.1.2.3
MDAQMD Regulation XII (Federal Operating Permits)	Implements operating permits requirements of CAA Title V.	Section 5.1.2.3

Table 5.1-1
Laws, Ordinances, Regulations and Standards (LORS)

LORS	Summary	AFC Section Explaining Conformance
MDAQMD Rule 1210 (Acid Rain Provisions of Federal Operating Permits)	Implements Acid Rain regulations of CAA Title IV.	Section 5.1.2.3
MDAQMD Rule 401 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 1 for periods greater than 3 minutes in any hour.	Section 5.1.2.3
MDAQMD Rule 402 (Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	Section 5.1.2.3
MDAQMD Rule 403 (Fugitive Dust)	Limits PM emissions from construction activity.	Section 5.1.2.3
MDAQMD Rule 404 (Particulate Matter)	Limits PM emissions from combustion sources.	Section 5.1.2.3
MDAQMD Rule 406 (Specific Contaminants)	Limits SO_2 emissions from stationary sources.	Section 5.1.2.3
MDAQMD Rule 407 (Liquid and Gaseous Air Contaminants)	Limits CO emissions from combustion sources.	Section 5.1.2.3
MDAQMD Rule 409 (Combustion Contaminants)	Limits PM emissions from combustion sources.	Section 5.1.2.3
MDAQMD Rule 431 (Sulfur Content of Fuels)	Limits the sulfur content of fuels combusted in stationary sources.	Section 5.1.2.3
MDAQMD Rule 475 (Electric Power Generating Equipment)	Limits NO_x and PM emissions from power generating equipment (e.g.., emergency engines, boilers).	Section 5.1.2.3
MDAQMD Rule 476 (Steam Generating Equipment)	Limits NO_x emissions from boilers.	Section 5.1.2.3

AFC = Application for Certification
ATSM = Airbone Toxic Control Measure
BACT = best available control technology
CAA = Clean Air Act
CARB = California Air Resources Board
CCR = California Code of Regulations
CEC = California Energy Commission
CEQA = Calfiornia Environmnetal Quality Act
CFR = Code of Federal Regulations
CO = Carbon monoxide
EPA = United States Environmental Protection Agency
HAP = Hazardous Air Particles
LORS = laws, ordinances, regulations and standards
MDAQMD = Mojave Desert Air Quality Management District
NEPA = National Environmnetal Policy Act
NESHAP = National Emission Standards for Hazardous Air Pollutants
NOx = Nitrous oxides
NSPS = New Source Performance Standards
NSR = New Source Review
PM = particulate matter
PSD = prevention of significant deterioration
SO_2 = Sulfur dioxide
USC = United States Code

5.1.2.1 Federal

National Environmental Policy Act

The NEPA establishes a public, interdisciplinary framework for Federal agencies reviewing projects under their jurisdiction to consider environmental impacts. NEPA's basic policy is to assure that all branches of government give proper consideration to the environment prior to undertaking any major federal action that significantly affects the environment.

The BLM, as lead Federal agency for the Project, is responsible for preparation of an Environmental Impact Statement (EIS) in compliance with NEPA to evaluate the environmental impacts of the portions of the Rio Mesa SEGF on federal lands. The Rio Mesa Solar III plant and the Project gen-tie line are located on lands administered and managed by the BLM. NEPA compliance is required for these portions of the Project through preparation of a Draft and Final EIS. BLM is also responsible for Native American consultation, including government to government consultation.

Clean Air Act

The U.S. Environmental Protection Agency (EPA) implements and enforces the requirements of many of the federal environmental laws. EPA Region 9, which has its offices in San Francisco, administers federal air programs in California. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the federal Clean Air Act:

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

Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52 - Prevention of Significant Deterioration (PSD) Program

Requirements: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding National Ambient Air Quality Standards (NAAQS) (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks, wilderness areas). Although this program is normally implemented at the local level with federal oversight, it is presently implemented in the MDAQMD by EPA Region 9.

The PSD requirements apply to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 TPY, or any other facility that emits at least 250 TPY.

Effective July 1, 2011, a stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source. A major modification is any project at a major stationary source that results in a significant increase in emissions of any PSD pollutant. A PSD pollutant is a criteria pollutant for which an area is classified as unclassified/attainment.

A significant increase for a PSD pollutant is an increase above the significant emission rate for that pollutant (Table 5.1-2) It is important to note that, once PSD is triggered by any pollutant, PSD requirements apply to any PSD pollutant with an emission increase above the significance level, regardless of whether the facility is a major source for that pollutant.

Table 5.1-2
PSD Significant Emission Thresholds

Pollutant	PSD Significant Emission Threshold[a] (tpy)
NOx	40
SO_2	40
CO	100
VOC	40
PM_{10}	15
$PM_{2.5}$	10
Lead	0.6
GHG[b]	75,000

Notes:
[a] 40 CFR 52.21 (b)(1)(23).
[b] PSD/Title V GHG Tailoring Rule, June 3, 2010.

The principal requirements for the PSD program are outlined below.

- Emissions of the PSD pollutants that are subject to PSD review must be controlled using BACT.
- Air quality impacts in combination with other increment-consuming sources must not exceed maximum allowable incremental increases.
- Air quality impacts of all sources in the area plus ambient pollutant background levels cannot exceed NAAQS.
- Pre- and/or post-construction air quality monitoring may be required.

The air quality impacts on soils, vegetation, and nearby PSD Class I areas (specific national parks and wilderness areas) must be evaluated. Because of its low emissions levels, the Rio Mesa SEGF is not expected to require a PSD permit.

Administering Agency: EPA Region 9.

Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52 - New Source Review (NSR)

Requirement: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of NAAQS. New source review jurisdiction has been delegated to the MDAQMD.

Administering Agency: MDAQMD.

Clean Air Act §401 (Title IV), 42 USC §7651 - Acid Rain Program

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

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Clean Air Act §501 (Title V), 42 USC §7661 - Title V Operating Permits Program

Requirements: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II Acid Rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. EPA has delegated authority for this program to MDAQMD.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Clean Air Act §111, 42 USC §7411; 40 CFR Part 60 - National Standards of Performance for New Stationary Sources

Requirements: Establishes national standards of performance to limit the emissions of criteria pollutants (air pollutants for which EPA has established NAAQS) from new or reconstructed facilities in specific source categories. Applicability of these regulations depends on equipment size, process rate, and date of construction. The Rio Mesa SEGF will be subject to the following NSPS:

- Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, is applicable to the Rio Mesa SEGF boilers associated with the three 250 MW power blocks. For natural gas fired units, Subpart Da includes the following emission limits:

- NOx: 0.11 lbs/MMBtu (30-day average)
- SOx: 1.4 lbs/MWh (30-day average)
- PM: 0.015 lbs/MMBtu

- Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is applicable to the emergency engines and the fire pump engines. These standards are enforced at the local level with federal and state oversight.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Clean Air Act §112, 42 USC §7412 - National Emission Standards for Hazardous Air Pollutants

Requirements: Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution, but for which NAAQS have not been established) from major sources of HAPs in specific source categories. These standards are implemented at the local level with federal oversight.

The requirements of 40 CFR 63 Subpart ZZZZ (National Emission Standards for Reciprocating Internal Combustion Engines) will apply to the emergency compression-ignition engines that are part of the project. For engines in this size range, compliance with the requirements of Subpart ZZZZ is achieved by purchasing engines that comply with the applicable NSPS (40 CFR 60 Subpart IIII).

40 CFR 63 Subpart JJJJJJ (National Emission Standards for Area Sources: Industrial/ Commercial/Institutional Boilers) does not include requirements for natural gas-fired boilers, so this regulation will not apply to the auxiliary boilers at the Rio Mesa SEGF.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Consistency with Federal Requirements

The MDAQMD has been delegated authority by the EPA to implement and enforce most federal requirements that are applicable to the project, including new source performance standards and new source review for nonattainment pollutants. Compliance with the MDAQMD regulations assures compliance and consistency with the corresponding federal requirements as well. The project would also be required to comply with the Federal Acid Rain requirements (Title IV). Because the MDAQMD is delegated authority to implement Title IV through its Title V permit program, the Title V Federal Operating Permit would include the necessary requirements for compliance with the Title IV Acid Rain provisions.

5.1.2.2 State

Warren-Alquist Act

The California Public Resources Code (PRC) establishes the CEC as the decision-making authority over land use decisions and environmental determinations during the AFC process. This is in accordance with

the Warren-Alquist Act, codified in §§ 25000 et seq. of the PRC. The CEC has exclusive jurisdiction over thermal power plant siting (50 MW or greater), including California Environmental Quality Act (CEQA) implementation. The Project will demonstrate conformity with state, regional, and local laws, including land use laws.

Under the Warren-Alquist Act, the CEC's licensing process is legally equivalent to CEQA and is guided by CEQA regulations.

California Environmental Quality Act

The CEC will be the lead agency enforcing CEQA for the Project. Under California law, the CEC is responsible for reviewing the AFCs filed for projects, and also has the role of lead agency for the environmental review of these projects under CEQA (PRC, §§ 25500 et seq; PRC, §§21000 et seq.). The CEC conducts this review in accordance with the administrative adjudication provisions of the Administrative Procedure Act (5 United States Code, §§ 500 et. seq.) and its own regulations governing site certification proceedings (CCR, Title 20, §§ 1701 et seq.). These provisions require the staff to conduct an independent analysis of AFCs and prepare an independent assessment of a project's potential environmental impacts, feasible mitigation measures, and alternatives as part of this process.

The CEC considers the Staff Assessment(s), along with the environmental analysis provided by the Applicant, as well as input from interested local, regional, State, and Federal agencies, intervenors, and interested Native American tribes, in developing its final decision on whether to issue a license for a proposed project. The CEC has a certified regulatory program under CEQA that exempts the agency from having to draft an Environmental Impact Report (EIR) and, instead, requires a Final Staff Assessment (FSA), evidentiary hearings, and a decision based on the hearing record, which includes the staff's and other parties' assessments.

The California Air Resources Board (CARB) was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the CAAQS; to review the operations of the local air pollution control districts (APCDs); and to review and coordinate preparation of the State Implementation Plan (SIP) for achievement of the NAAQS. CARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California Health & Safety Code (HSC):

- SIP
- California Clean Air Act
- Toxic Air Contaminant Program
- Airborne Toxic Control Measure for Stationary Compression-Ignition Engines
- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and CARB Memorandum of Understanding
- Climate Change Regulatory Program

Health & Safety Code (HSC) §39500 et seq. - State Implementation Plan (SIP)

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

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

HSC §40910 – 40930 - California Clean Air Act

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

Administering Agency: MDAQMD, with CARB oversight

HSC §39650 – 39675 - Toxic Air Contaminant (TAC) Program

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

Administering Agency: CARB

Title 17, California Code of Regulations, §93115 - Airborne Toxic Control Measure for Stationary Compression-Ignition Engines

Requirements: The purpose of the airborne toxic control measure (ATCM) is to reduce Diesel particulate matter (DPM) and criteria pollutant emissions from stationary Diesel-fueled compression ignition engines. The ATCM applies to stationary compression-ignition engines with a rating greater than 50 brake horsepower. The ATCM requires the use of CARB-certified Diesel fuel or equivalent, and limits emissions from, and operations of, compression ignition engines.

Administering Agency: MDAQMD and CARB

CA Health & Safety Code §41700 - Nuisance Regulation

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

Administering Agency: MDAQMD and CARB

H& SC §44300-44384; 17 CCR §93300-93347 - Air Toxic "Hot Spots" Act

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

Administering Agency: MDAQMD with CARB oversight.

CEC and CARB Memorandum of Understanding

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

Requirements: Provides for the inclusion of requirements in the CEC's decision on an AFC to assure protection of environmental quality; thus the AFC is required to include information concerning air quality protection.

Administering Agency: CEC

Stats. 2006, Ch. 488 and CA Health & Safety Code § 38500-38590 - California Climate Change Regulatory Program

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

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

- June 30, 2007: Identify a list of discrete early action GHG emission reduction measures (first report published April 20, 2007, with additional measures adopted on October 25, 2007).
- January 1, 2008: Establish a statewide GHG emission cap for 2020 that is equivalent to 1990 emissions.
- January 1, 2008: Adopt mandatory reporting rules for significant sources of GHGs.
- January 1, 2009: Adopt a scoping plan that will indicate how GHG emission reductions will be achieved from significant GHG sources through regulations, market-based compliance mechanisms, and other actions, including recommendation of a de minimis threshold for GHG emissions, below which sources would be exempt from reduction requirements.
- January 1, 2011: Adopt regulations to achieve maximum technologically feasible and cost-effective GHG emission reductions, including provisions for both market-based and alternative compliance mechanisms.
- January 1, 2012: Regulations adopted prior to January 1, 2010, become effective.

Senate Bill (SB) 97, adopted August 21, 2007, requires the California Office of Planning and Research (OPR) to develop CEQA guidelines ―for the mitigation of GHG emissions or the effects of GHG emissions" by July 1, 2009. SB 97 further requires the Resources Agency Secretary to adopt these CEQA guidelines by January 1, 2010. Finally, SB 97 removes GHG emissions as a cause of action under CEQA for specified state-financed infrastructure projects until January 1, 2010.

The AFC is required to include the project's emission rates of greenhouse gases (CO_2, CH_4, N_2O, and SF_6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources.

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

Administering Agencies**: CARB and CEC.**

Consistency with State Requirements

As discussed in Section 5.1.2.2, state law set up local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. The proposed project is under the local jurisdiction of the MDAQMD, and compliance with MDAQMD regulations will assure compliance with state air quality requirements.

5.1.2.3 Local

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county, regional (including the MDAQMD), and unified. In addition, special air quality management district (AQMDs), with more comprehensive authority over non-vehicular sources, as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California. Local districts have principal responsibility to do the following:

- Develop plans for meeting the NAAQS and California ambient air quality standards;
- Develop control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implement permit programs established for the construction, modification, and operation of sources of air pollution;
- Enforce air pollution statutes and regulations governing non-vehicular sources; and
- Develop programs to reduce emissions from indirect sources.

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

HSC §40914 - Mojave Desert Air Quality Plans

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

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

HSC §4000 et seq., HSC §40200 et seq., indicated MDAQMD Rules - MDAQMD Rules and Regulations

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

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

Authority to Construct

Regulation II—Permits, Rule 201 (Permit to Construct) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to

Construct from the MDAQMD. Under Regulation XIII Rule 1306 (Electric Energy Generating Facilities) Section (E)(3)(b), the District's Final Determination of Compliance acts as an authority to construct for a power plant upon approval of the project by the CEC.

Review of New or Modified Sources

Regulation XIII (New Source Review) implements the federal NSR and PSD programs, as well as the New Source Review requirements of the California Clean Air Act. The rule contains the following elements:

- BACT and Lowest Achievable Emission Rates (LAER)
- Emission offsets
- Air quality impact analysis (AQIA)

Best Available Control Technology (BACT)

BACT must be applied to any new or modified permit unit which has a potential to emit 25 pounds per day or more of any Nonattainment Air Pollutant. The Nonattainment Air Pollutants are ozone and its precursors NO_x and VOC, and particulate matter (PM_{10}) and its precursors NOx, SOx, and VOC.

The MDAQMD defines BACT (Rule 1301(K)(2)) for a non-major facility as the most stringent emission limitation or control technique that:

- Has been achieved in practice for the category or class of source; or
- Is any emission limitation or control technique determined to be technologically feasible and cost-effective; or
- Is contained in any SIP approved by EPA for such emission unit category, unless demonstrated to not be proven in field application, not be technologically feasible, or not be cost-effective.

Emission Offsets

A new or modified facility resulting in facility-wide emission increases above the thresholds shown in Table 5.1-3 must offset emission increases of nonattainment pollutants (and their precursors).

Table 5.1-3
MDAQMD Offset Emission Thresholds

Pollutant	Offset Threshold, tpy
CO	100
Hydrogen Sulfide	10
Lead	0.6

Table 5.1-3
MDAQMD Offset Emission Thresholds

Pollutant	Offset Threshold, tpy
PM_{10}	15
NOx	25
SOx	25
VOC	25

Source: MDAQMD Regulation XIII, Rule 1303 (B)(1)

Toxic Risk Management

Regulation XIII, Rule 1320 (New Source Review for Toxic Air Contaminants) provides a mechanism for evaluating the potential impact of air emissions of toxic air contaminant (TAC, also called non-criteria pollutants) from new, modified, and relocated facilities or permit units in the MDAQMD. The rule imposes more stringent requirements on permit units with higher risks, as shown in Table 5.1-4.

Table 5.1-4
MDAQMD Health Risk Thresholds

Requirement	Risk Threshold	Hazard Index
Utilize TBACT	1×10^{-6} (residential receptor) 1×10^{-5} (point of maximum impact)	--
Public Notification	10×10^{-5}	1
Application Denial	100×10^{-5}	10

CEC Review

Regulation XIII, Rule 1306 establishes a procedure for coordinating MDAQMD review of power plant projects with the CEC's AFC and Small Power Plant Exemption (SPPE) processes. Under this rule, the MDAQMD reviews the AFC/SPPE and issues a Determination of Compliance for a proposed project. Upon approval of the project by the CEC, this Determination of Compliance is equivalent to an Authority to Construct. A Permit to Operate is issued following demonstration of compliance with all permit conditions.

Prevention of Significant Deterioration

In the MDAQMD the Federal PSD program is administered by EPA, Region IX.

Acid Rain Permit

Regulation XII Rule 1210 (Acid Rain Provisions of Federal Operating Permits) adopts, by reference, the federal requirements of 40 CFR Part 72, which requires that certain subject facilities comply with maximum operating emissions levels for SO_2 and NOx, and monitor SO_2, NOx, and carbon dioxide emissions and exhaust gas flow rates. A Phase II Acid Rain facility, such as a new power plant project, must obtain an Acid Rain permit. A permit application must be submitted to the MDAQMD at least 24 months before operation of the new unit commences. The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations.

Federal Operating Permit

Regulation XII (Federal Operating Permits) requires new or modified major facilities, NSPS sources, NESHAP sources, and/or Phase II Acid Rain facilities to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the 1990 Clean Air Act Amendments. A Title V permit application for a new or modified source must be submitted to the MDAQMD within 12 months of commencing operation. The application must present a process description, all new stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification.

New Source Performance Standards

Regulation IX Rule 900 (Standards of Performance for New Stationary Sources) adopts, by reference, the federal standards of performance for new or modified stationary sources. The NSPS for Electric Utility Steam Generation Units (40 CFR 60, Subpart Da) applies to new large boilers (>250 MMBtu/hr capacity) that make steam used to generate electricity. The applicability and requirements of the New Source Performance Standards are discussed above under the federal regulations section.

MDAQMD Prohibitory Rules

The general prohibitory rules in Regulation IV applicable to the project are summarized below.

Rule 401– Visible Emissions: Prohibits visible emissions as dark as, or darker than, Ringelmann No. 1 for periods greater than three minutes in any hour.

Rule 402– Nuisance: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.

Rule 403—Fugitive Dust: Prohibits visible dust emissions off property due to transport, handling, construction, or storage activity. Requires dust minimization during grading and clearing of land. Limits the difference between upwind and downwind PM concentrations of 100 µg/cubic meter (5 hour average). Requires removal of particulate matter from equipment prior to movement on paved streets.

Rule 403.2—Fugitive Dust Control for the Mojave Desert Planning Area: The project lies outside the Mojave Desert Planning Area.

Rule 404 – Particulate Matter: Prohibits PM emissions in excess grains per dry standard cubic foot (gr/dscf) limits based on the exhaust flow rate of the equipment in question. This rule applies to the boilers and engines at the proposed project.

Rule 406 – Specific Contaminants: Prohibits sulfur emissions, calculated as SO_2, in excess of 0.05 percent by volume (500 parts per million by volume, ppmv), and acid gas emissions above specified levels. This rule applies to the boilers and engines at the proposed project.

Rule 407 – Liquid and Gaseous Air Contaminants: Prohibits carbon monoxide emissions in excess of 2000 parts per million by volume, ppmv. This rule applies to the boilers and engines at the proposed project.

Rule 409 – Combustion Contaminants: This rule prohibits PM emissions in excess of 0.1 gr/dscf from combustion equipment. This rule applies to the boilers and engines at the proposed project.

Rule 431 – Sulfur Content of Fuels: Prohibits the burning of gaseous fuel with a sulfur content of more than 800 ppm and liquid fuel with a sulfur content of more than 0.5 percent sulfur by weight. This rule applies to the boilers and engines at the proposed project.

Rule 475 – Electric Power Generating Equipment: Limits NO_x and PM emissions from electrical generating equipment rated greater than or equal to 50 MMBtu/hr to RACT levels. The NO_x and PM limits of this rule apply to the auxiliary and startup boilers at the proposed project (NO_x limit = 80 ppmv @ 3 percent O2; PM limit not to exceed 0.01 gr/dscf @ 3 percent O2 and 11 lbs/hour).

Rule 476 – Steam Generating Equipment: Limits NO_x emissions from steam generators rated above 50 MMBtu/hr to 125 ppm. This rule applies to the boilers at the proposed project.

Rule 1157 – Boilers and Process Heaters : Limits CO and NO_x from boilers. Applies only to boilers located within the Federal Ozone Nonattainment Area, which as defined in the rule includes only portions of San Bernardino County. Therefore this rule is not applicable to the proposed project.

Rule 1158 – Electric Utility Operations : Limits NO_x from electrical generating steam boilers. Applies only to boilers located within the Federal Ozone Nonattainment Area, which as defined in the rule includes only portions of San Bernardino County. Therefore this rule is not applicable to the proposed project.

Rule 1160 – Internal Combustion Engines: Limits emissions from internal combustion engines. Applies only to engines located within the Federal Ozone Nonattainment Area, which as defined in the rule includes only portions of San Bernardino County. Therefore this rule is not applicable to the proposed project.

5.1.3 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants and the existing air quality within the Project region. The data presented in this section are considered to be reasonably representative of the project site.

The Rio Mesa SEGF consists of the project site, linears, and a temporary laydown area (Figure 2-2, Project Features Map, Section 2.0). The project site is located in an unincorporated area of Riverside County south of Interstate 10, about 6 miles southwest of the Blythe Airport (about 13 miles southwest of downtown Blythe).

5.1.3.1 Geography and Topography

The project site is on the western slope of the Lower Colorado River Valley (on the pediment, outside the irrigated zone), approximately 392 feet above mean sea level.

5.1.3.2 Climate and Meteorology

Consistent with the typical weather of the interior deserts of Southern California, eastern Riverside County in general has an arid climate characterized by very low precipitation, hot summers, and mild winters. Temperature inversions occur, but are not as strong as in coastal areas, where the marine influence is important. The area's climatic conditions are strongly influenced by the large-scale sinking and warming of air in the semi-permanent subtropical high-pressure center over the eastern Pacific. This high-pressure system effectively blocks out most mid-latitude storms, except in winter when the ridge is weaker and farther south. The coastal mountains to the west also have a major influence on climate, serving as a meteorological boundary that effectively removes moisture from the marine air flowing from the Pacific.

The nearest full-time meteorological monitoring station to the proposed project site is maintained at the Blythe Airport approximately 6 miles northeast of the project site. Based on 86 years of climate data available from U.S. Historical Climatological Network (1909-1994), the annual average temperature measured at Blythe is 70 degrees Fahrenheit (°F). Temperatures of 32°F or below rarely occur at this station, but temperatures of 100°F or above are more frequent, occurring from June through September. During the fall, Santa Ana winds can last for several days. These are strong, dry northerly winds from the Great Basin and result in high temperatures (greater than 90°F) and low relative humidity (often below 20 percent) in the project area.

Eastern Riverside County receives a portion of its annual rainfall from November to March, when the semi-permanent high-pressure system over the eastern Pacific Ocean moves south, allowing storms to move through the area; and another portion of its annual rainfall at the height of summer, when the southwestern monsoon is present. In August, the boundary between the easterly, tropical trade winds and the mid-latitude westerlies sometimes moves north of the project site, and thunderstorms, sometimes even mesoscale convective complexes of thunderstorms, can be present in the vicinity. The average annual precipitation at the project site is about 3.5 inches. Local wind circulations are channeled north-south by the presence of the Colorado River Valley. Winds are typically of light to moderate strength from either the northwest or the southwest, and channeled by the river valley. Composite annual and quarterly wind roses are shown in Figures 5.1-1 through 5.1-5 (figures are provided at the end of this section). Individual annual and quarterly wind roses and quarterly wind frequency distributions for the project area are provided in Appendix 5.1A.

The nearest long-term meteorological station with available temperature and precipitation means and extremes is the National Weather Service Blythe CAA Airport station. This weather station is located

approximately 6 miles to the northeast of the Project at latitude 33°37‘N, longitude 114°43‘W. Data collected at this station over a 60-year period (1949-2010) are presented in Table 5.1-5. The hottest month, July, has an average maximum temperature of 108.4°F and an average minimum temperature of 81.1°F. The coldest month, January, has an average maximum temperature of 66.8°F and an average minimum temperature of 41.6°F.

Table 5.1-5
Average Temperature and Precipitation Data at Blythe (1949-2010)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Average Max. Temperature (°F)	66.8	72.0	78.4	86.4	95.2	104.5	108.4	106.7	101.4	89.8	76.0	66.6	87.7
Average Min. Temperature (°F)	41.6	45.4	50.2	56.5	64.5	72.7	81.1	80.2	73.1	60.8	48.6	41.2	59.7
Average Total Precipitation (in.)	0.49	0.44	0.36	0.15	0.02	0.02	0.23	0.62	0.35	0.26	0.20	0.41	3.54

Source: Western Regional Climate Center (http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?ca0927)
Note: °F = degrees Fahrenheit

Monthly mean precipitation amounts at Blythe range from 0.62 inches in August to 0.02 inches in May or June. Relative humidity levels are generally low. In the summer relative humidity averages 20 to 40 percent in the early morning and 10 to 30 percent in the afternoon. In winter, relative humidity averages 30 to 50 percent in the early morning and 10 to 30 percent in the afternoon. Wind speeds are normally light or calm.

5.1.3.3 Overview of Air Quality Standards

The EPA has established NAAQS for ozone, NO_2, CO, SO_2, PM_{10}, $PM_{2.5}$, and airborne lead. Areas with ambient levels above these standards are designated by EPA as ―nonattainment areas” subject to planning and pollution control requirements that are more stringent than standard requirements.

The CARB has established California ambient air quality standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, $PM_{2.5}$, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 5.1-6 presents the NAAQS and CAAQS for selected pollutants. The California standards are generally set at concentrations lower than the federal standards and, in some cases, have shorter averaging periods.

Table 5.1-6
National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards		Federal Standards		
		Concentration	Method	Primary	Secondary	Method
Ozone	1 Hour	0.09 ppm (180 µg/m3)	Ultraviolet Photometry	--	Same as Primary Standard	Ultraviolet Photometry
	8 Hour	0.07 ppm (137 µg/m3)		0.075 ppm (147 µg/m3)		
Respirable Particulate Matter (PM_{10})	24 Hour	50 µg/m3	Gravimetric or Beta Attenuation	150 µg/m3	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	20 µg/m3		--		
Fine Particulate Matter ($PM_{2.5}$)	24 Hour	No Separate State Standard		35 µg/m3 a	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	12 µg/m3	Gravimetric or Beta Attenuation	15.0 µg/m3		
Carbon Monoxide (CO)	8 Hour	9.0 ppm (1 mg.m3)	Non-Dispersive Infrared Photometry (NDIR)	9 ppm (10 mg.m3)	None	Non-Dispersive Infrared Photometry (NDIR)
	1 Hour	20 ppm (23 mg.m3)		35 ppm (40 mg/m3)		
Nitrogen Dioxide (NO2)	Annual Arithmetic Mean	0.030 ppm (57 µg/m3)	Gas Phase Chemiluminescence	53 ppb (100 µg/m3)	Same as Primary Standard	Gas Phase Chemiluminescence
	1 Hour	0.18 ppm (339 µg/m3)		100 ppb b (188 µg/m3)	None	
Sulfur Dioxide (SO2)	24 Hour	0.04 ppm (105 µg/m3)	Ultraviolet Fluorescence	--	--	Ultraviolet Fluorescence Spectrophotometry (Parasaniline Method)
	3 Hour	--		--	0.5 ppm (1300 µg/m3)	
	1 Hour	0.25 ppm (655 µg/m3)		75 ppbc (196 µg/m3)	--	
Lead	30 Day Average	1.5 µg/m3	Atomic Absorption	--	--	--
	Calendar Quarter	--		1.5 µg/m3	Same as Primary Standard	High Volume Sampler and Atomic Absorption
	Rolling 3-Month Average	--		0.15 µg/m3		

Table 5.1-6
National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards		Federal Standards		
		Concentration	Method	Primary	Secondary	Method
Visibility Reducing Particles	8 Hour	Extinction Coefficient of 0.23 per kilometer—visibility of ten miles or more due to particles when relative humidity is less than 70 percent. Method: Beta Attenuation and Transmittance through Filter Tape.		No Federal Standards		
Sulfates	24 Hour	25 µg/m3	Ion Chromatography			
Hydrogen Sulfide	1 Hour	0.03 ppm (42 µg/m3)	Ultraviolet Fluorescence			
Vinyl Chloride	24 Hour	0.01 ppm (26 µg/m3)	Gas Chromatography			

Notes:
a To attain this standard, the 3-year average of the 98th percentile of the daily concentrations must not exceed 35 µg/m3.
b To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hr average must not exceed 100 ppb.
c To attain this standard, the 3-year average of the 99th percentiles of the daily maximum 1-hr average must not exceed 75 ppb.

5.1.3.4 Existing Air Quality

All ambient air quality data presented in this section were published by CARB on the ADAM website and/or by EPA on the AirData data website. Ambient air concentrations of ozone (O_3), NO_2, SO_2, CO, PM_{10}, and $PM_{2.5}$ are recorded at monitoring stations in Riverside County. The immediate area surrounding the project site (within 1.5 to 2 miles) is an area with sparse population. Further out, areas to the north, northwest, west, and southwest are all vacant with very sparse population. However, there are suburban areas with moderate residential areas more than 2 miles to the east (Blythe). The monitoring stations were generally positioned to represent area-wide ambient conditions rather than the localized impacts of any particular emission source or group of sources. In rural areas of the county, pollutant concentrations are not expected to vary dramatically from one location to the next, because the emission sources are few and widely distributed.

Ambient air quality monitoring data for ozone, PM_{10}, $PM_{2.5}$, CO, NO_2, and SO_2 were compared to the most stringent applicable standards for the years 2006 through 2010 at the most representative monitoring stations for each pollutant. Ozone data are from the Blythe-445 West Murphy Street monitoring station; PM_{10}, $PM_{2.5}$, NO_2, and CO data are from the Palm Springs Fire Station monitoring station; and SO_2 data are from the Victorville-14306 Park Avenue monitoring station. Airborne lead levels are taken from the San Bernardino-24302 4th Street monitoring station. The locations of these monitoring stations relative to the project site are shown in Figure 5.1-6. The representativeness of the data collected at these monitoring stations for the project site is discussed in Appendix 5.1H.

Ozone (O_3)

Ozone is an end-product of complex reactions between VOC and NO_x in the presence of ultraviolet solar radiation. VOC and NO_x emissions from vehicles and stationary sources, combined with daytime wind

flow patterns, mountain barriers, temperature inversions, and intense sunlight, generally result in the highest O_3 concentrations. The entire Mojave Desert air basin is classified as a nonattainment area with respect to state ambient standards for ozone, and the project location within the air basin is an unclassified/attainment area with respect to national ambient standards for ozone. Table 5.1-7 shows the measured ozone levels at the Blythe monitoring station during the period from 2006 to 2010. The 1-hour ozone CAAQS of 0.09 parts per million (ppm) was not exceeded from 2006 to 2010.

The federal 8-hour ozone NAAQS requires that the 3-year average of the fourth-highest values for individual years be maintained at or below 0.075 ppm. Therefore, the number of days in each year with maximum 8-hour concentrations above the standard in Table 5.1-7 does not equate to the number of violations.

Table 5.1-7
Ozone Levels at Blythe (ppm)

Blythe Station, Riverside County	2006	2007	2008	2009	2010
Maximum 1-hour Average	0.078	0.092	0.074	0.072	0.072
Number of Days Exceeding California 1-hour Standard (0.09 ppm)	0	0	0	0	0
Number of Days Exceeding Old National 1-hour Standard (0.12 ppm)a	0	0	0	0	0
Maximum 8-hour Average	0.059	0.076	0.071	0.066	0.068
Number of Days Exceeding California 8-hour Standard (0.07 ppm)	0	1	1	0	0
Number of Days Exceeding National 8-hour Standard (0.075 ppm)b	0	0	0	0	0

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html).

a EPA revoked the 1-hour ozone standard in all areas on June 15, 2005.
b To attain this standard, the 3-year average of the fourth-highest maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm. (Effective May 27, 2008).
ppm = parts per million.

Nitrogen Dioxide (NO_2)

NO_2 is formed primarily from reactions in the atmosphere between NO (nitric oxide) and oxygen (O_2) or ozone. NO is formed during high-temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is much less harmful than NO_2, it can be converted to NO_2 in the atmosphere within a matter of hours, or even minutes, under certain conditions. The control of NO and NO_2 emissions is also important because of the role of both compounds in the atmospheric formation of ozone.

Table 5.1-8 shows NO_2 levels recorded at the Palm Springs station for the years 2006 through 2010.

The Mojave Desert air basin is classified as an attainment area with respect to state ambient standards for NO_2 and an unclassified/attainment area with respect to national ambient standards for NO_2. During the period from 2006 to 2010, there were no violations of the CAAQS 1-hour standard (0.18 ppm) at any monitoring station in Riverside County. The highest 1-hour concentration recorded at the Palm Springs Fire Station monitoring station during the years 2006 to 2010 was 0.093 ppm in 2006. A new federal 1-hour NO_2 standard of 0.100 ppm became effective on April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within Mojave Desert air basin must not exceed 0.100 ppm. Table 5.1-8 also shows that there were no violations of the annual NAAQS (0.053 ppm) or annual CAAQS (0.030 ppm) at the Palm Springs Fire Station monitoring station during this period.

Table 5.1-8
Nitrogen Dioxide Levels at Palm Springs (ppm)

Palm Springs Fire Station Monitoring Station, Riverside County	2006	2007	2008	2009	2010
Maximum 1-hour Average	0.093	0.063	0.049	0.048	0.046
Annual Average	0.011	0.010	0.009	0.008	0.009
Days Over State Standard (0.18 ppm, 1-hour)	0	0	0	0	0
Days Over Federal Standard (0.100 ppm, 1-hour)[a]	0	0	0	0	0

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html).

Notes:
new federal 1-hour average NO2 standard of 0.100 ppm was announced by EPA on February 9, 2010 and became effective April 12, 2010. To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average values at each monitor must not exceed 100 ppb.

Daily max values were obtained from EPA AirExplorer (http://www.epa.gov/airexplorer/index.htm), Query Concentrations. None of the daily max values from 2006 to 2010 exceeded the new federal 1-hour average standard of 100 ppb, indicating no exceedances occurred in any of the days.

ppm = parts per million

Carbon Monoxide (CO)

Carbon monoxide is a product of incomplete combustion and is emitted principally from automobiles and other mobile sources of pollution. It is also a product of combustion from stationary sources (both industrial and residential) burning fuels. Peak CO levels occur typically during winter months due to a combination of higher emission rates and stagnant weather conditions.

Table 5.1-9 shows the available data on maximum 1-hour and 8-hour average CO levels recorded at the Palm Springs Fire Station monitoring station during the period from 2006 to 2010. As indicated by this table, the maximum measured 1-hour average CO levels comply with the NAAQS and CAAQS (35.0 ppm and 20.0 ppm, respectively) and the maximum 8-hour values comply with the NAAQS and CAAQS

of 9.0 ppm. The highest individual 1-hour and 8-hour CO concentrations at this station during the period from 2006 to 2010 were 2.3 ppm and 0.9 ppm, respectively, both recorded in 2006. The project location within the Mojave Desert air basin is an unclassified area with respect to the state CO ambient standard, and the entire Mojave Desert air basin is an unclassified/attainment area with regards to the federal CO standards.

Table 5.1-9
Carbon Monoxide Levels at Palm Springs (ppm)

Palm Springs Fire Station Monitoring Station, Riverside County	2006	2007	2008	2009	2010
Maximum 1-hour Average[a]	2.3	1.5	1.0	2.3	1.6
Maximum 8-hour Average	0.85	0.79	0.54	0.67	0.56
Days Over the 8-hour California Standard (9 ppm)	0	0	0	0	0
Days Over the 8-hour Federal Standard (9 ppm)	0	0	0	0	0

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html)

[a] 2009 and 2010 Max 1-hour Average obtained from http://www.epa.gov/mxplorer/index.htm, "Query Concentrations" function and the "24 Hourly Measurements for a Site and Day" on CARB ADAM Website (www.arb.ca.gov/adam/welcome.html)

ppm = parts per million

Sulfur Dioxide (SO_2)

SO_2 is produced by the combustion of any sulfur-containing fuel. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains nearly negligible sulfur, whereas fuel oils may contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. The Mojave Desert air basin is considered to be in attainment with respect to the state air quality standard and unclassified with respect to the federal air quality standard for SO_2.

Table 5.1-10 shows the available data on maximum 1-hour, 3-hour, 24-hour, and annual average SO_2 levels recorded at the Victorville station during the period from 2006 to 2010. As indicated by this table, the maximum measured 1-hour average SO_2 levels comply with the new NAAQS (75 ppb) and CAAQS (0.25 ppm); the maximum 3-hour average SO_2 levels comply with the NAAQS (0.5 ppm); and the maximum 24-hour values comply with the NAAQS and CAAQS of 0.14 ppm and 0.04 ppm, respectively. The table also demonstrates compliance with the annual SO_2 NAAQS of 0.03 ppm. Note that the 24-hour and annual NAAQS for SO_2 have been superseded by the new 1-hour NAAQS, which became effective on August 23, 2010.

Table 5.1-10
Sulfur Dioxide Levels at Victorville (ppm)

Victorville Station, San Bernardino County	2006	2007	2008	2009	2010
Highest 1-hour average	0.018	0.009	0.006	0.028	0.052
Highest 3-hour average	0.012	0.006	0.005	0.028	0.043
Highest 24-hour average	0.005	0.005	0.002	0.005	0.007
Annual Average	0.002	0.001	0.001	0.001	0.001
Days Over 1-hour State Standard (0.25 ppm)	0	0	0	0	0
Days Over 1-hour Federal Standard (75 ppb)[a]	NA	NA	NA	NA	NA
Days Over 24-hour State Standard (0.04 ppm)	0	0	0	0	0
Days Over 3-hour Federal Standard (0.5 ppm)	0	0	0	0	0

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html)

a Final rule signed June 22, 2010, effective August 23, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

NA = not applicable
ppm = parts per million

Particulates

Respirable Particulate Matter (PM_{10})

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources and manufacturing processes; and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides. Particulates with a diameter less than or equal to 10 microns are referred to as PM_{10}, and are regulated because they can be inhaled, leading to health effects. Fine particulates, referred to as $PM_{2.5}$ and having a diameter equal to or less than 2.5 microns, are a subset of PM_{10} that are also regulated. $PM_{2.5}$ standards are discussed later in this section.

Table 5.1-11 shows the maximum PM_{10} levels recorded at the Palm Springs Fire Station monitoring station during the period from 2006 through 2010 and the arithmetic annual average concentrations for the same period. (The arithmetic annual average is simply the arithmetic mean of the daily observations.) PM_{10} is monitored according to different protocols for evaluating compliance with the state and federal standards for this pollutant. Specifically, California uses a gravimetric or beta attenuation method, whereas compliance with federal standards is evaluated based on an inertial separation and gravimetric analysis. This accounts for the slightly differing 24-hour concentrations listed in Table 5.1-11 that represent data obtained by means of the state and federal samplers.

Table 5.1-11
Particulate Matter (PM_{10}) Levels at Palm Springs ($\mu g/m^3$)

Palm Springs Fire Station Monitoring Station, Riverside County	2006	2007	2008	2009	2010
Maximum 24-hour Average (federal testing samplers)	226.0	83.0	75.0	140.0	37.0
Maximum 24-hour Average (state testing samplers)	222.0	81.0	73.0	133.0	-- [b]
Annual Arithmetic Meana	28.0	30.0	17.7	20.4	18.8
Estimated Number of Days Exceeding Federal Standard (150 $\mu g/m^3$)	6.6	0	-- [b]	-- [b]	0
Estimated Number of Days Exceeding State Standard (50 $\mu g/m^3$)	19.6	0	0	-- [b]	-- [b]

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html)

a On December 17, 2006, the annual PM_{10} federal standard (50 $\mu g/m^3$) was revoked.

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

$\mu g/m^3$ = micrograms per cubic meter
PM_{10} = particulate matter less than 10 microns in diameter

At the Palm Springs Fire Station monitoring station, the maximum 24-hour PM_{10} levels exceed the CAAQS state standard of 50 micrograms per cubic meter ($\mu g/m^3$) a number of times per year. The maximum daily concentration[1] recorded during the analysis period was 222 $\mu g/m^3$ (state samplers) in 2006. The maximum annual arithmetic mean concentration recorded at Palm Springs was 30.0 $\mu g/m^3$ in 2007, which is above the state standard of 20 $\mu g/m^3$. The federal annual PM_{10} standard was revoked by the EPA in 2006 due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution. The attainment status of the project location within Riverside County is ―unclassified" with respect to the federal PM_{10} standard, and nonattainment with respect to the state PM_{10} standards.

Fine Particulates ($PM_{2.5}$)

Fine particulates result from fuel combustion in motor vehicles and industrial processes, residential and agricultural burning, and atmospheric reactions involving NOx, SOx, and organics. Fine particulates are referred to as $PM_{2.5}$ and have a diameter equal to or less than 2.5 microns. In 1997, EPA established annual and 24-hour NAAQS for $PM_{2.5}$ for the first time. The most recent revision to the standard regulating the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations (35 $\mu g/m^3$) became effective on December 17, 2006.

The $PM_{2.5}$ data in Table 5.1-12 show that the national 24-hour average NAAQS of 35 $\mu g/m^3$ was not exceeded from 2006 to 2010. The maximum recorded 24-hour average 98th percentile value was 21

[1] Excluding approved exceptional events.

μg/m^3 in 2006. The annual $PM_{2.5}$ data are also presented in this table. The maximum annual arithmetic mean was 8.5 μg/m^3, recorded in 2007, which is below the national and stand standards of 15 and 12 μg/m^3, respectively. The project location within Riverside County is in attainment with regard to the federal $PM_{2.5}$ standards and is unclassified/attainment with regard to the state $PM_{2.5}$ standard.

Table 5.1-12
Particulate Matter ($PM_{2.5}$) Levels at Palm Springs (μg/m^3)

Palm Springs Fire Station Monitoring Station, Riverside County	2006	2007	2008	2009	2010
Maximum 24-hr Average 98th Percentile[a]	21	20	18	17	15
Annual Arithmetic Mean	7.8	8.5	7.1	6.5	5.9
Estimated Number of Days Exceeding Federal Standard (35 μg/m^3)	0	0	0	0	0

Sources: CARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html)

[a] EPA lowered the 24-hour standard from 65 μg/m^3 to 35 μg/m^3 on December 17, 2006. Compliance with this standard is based on the 3-year average of the 98th percentile daily concentrations.

μg/m^3 = micrograms per cubic meter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

Airborne Lead (Pb)

Lead pollution has historically been emitted predominantly from the combustion of fuels; however, legislation in the early 1970s required a gradual reduction of the lead content of gasoline. Beginning with the introduction of unleaded gasoline in 1975, lead levels have been dramatically reduced throughout the U.S., including California, and violations of the ambient standards for this pollutant have been virtually eliminated.

On October 15, 2008, EPA revised the federal ambient air quality standard for lead, lowering it from 1.5 μg/m^3 to 0.15 μg/m^3 for both the primary and the secondary standard. EPA determined that numerous health studies are now available that demonstrate health effects at much lower levels of lead than previously thought. EPA subsequently published the final rule in the Federal Register on November 12, 2008. This is the first time that the federal lead standard has been revised since it was first issued in 1978.

In addition to revising the level of the standard, EPA changed the averaging time from a quarterly average to a rolling three-month average. The level of the standard is ―not to be exceeded" and is evaluated over a three-year period. Lead levels are measured as lead in total suspended particulate (TSP). The revised lead standard also includes new monitoring requirements.

Ambient lead levels are monitored in San Bernardino. Table 5.1-13 lists the federal air quality standard for airborne lead and the levels reported in San Bernardino between 2006 and 2010. Maximum quarterly levels are not reported on EPA's website; because the maximum 24-hour averages must be higher than the quarterly average, the data show that lead levels are actually well below the federal standard. The

Mojave Desert air basin is in attainment with respect to the state ambient standard for lead; there is no area designation information for the federal standard.

Table 5.1-13
Airborne Lead (Pb) Levels at San Bernardino (µg/m^3)

San Bernardino Monitoring Station, San Bernardino County	2006	2007	2008	2009	2010
Maximum 24-hour Average	0.03	0.07	0.02	0.02	0.02
Number of Days Exceeding Federal Standard (1.5 µg/m^3)	0	0	0	0	0

Sources: EPA AirData Website (http://www.epa.gov/air/data/index.html)
2009 and 2010 Max 24-hour Average obtained from http://www.epa.gov/mxplorer/index.htm, "Query Concentrations" function
Notes:
µg/m^3 = micrograms per cubic meter

Particulate Sulfates

Sulfate compounds found in the lower atmosphere consist of both primary and secondary particles. Primary sulfate particles are directly emitted from open pit mines, dry lakebeds, and desert soils. Fuel combustion is another source of sulfates, both primary and secondary. Secondary sulfate particles are produced when oxides of sulfur (SOx) emissions are transformed into particles through physical and chemical processes in the atmosphere. Particles can be transported long distances. The Mojave Desert air basin is in attainment with respect to the state ambient standard for sulfates; there is no federal standard.

Other State-Designated Criteria Pollutants

Along with sulfates, California has designated hydrogen sulfide and visibility-reducing particles as criteria pollutants, in addition to the federal criteria pollutants. The Mojave Desert air basin remains unclassified for both pollutants.

5.1.4 Environmental Analysis

Ambient air quality impact analyses for the Project have been conducted to satisfy the MDAQMD and CEC requirements for analysis of impacts from criteria pollutants (NO_2, CO, PM_{10}, $PM_{2.5}$, and SO_2) and noncriteria pollutants during project construction and operation. The analyses cover each phase of the project. Section 5.1.4.1 gives an overview of the analytical approach and the emitting units at the facility. Section 5.1.4.2 discusses facility operations. Section 5.1.4.3 presents the emissions for project operation and construction of the project. Section 5.1.4.4 discusses emissions and fuel use monitoring, and Section 5.1.4.5 presents the ambient air quality impacts of project construction and operation.

5.1.4.1 Overview of the Analytical Approach to Estimating Facility Impacts

The following sections describe the emission sources that have been evaluated, the results of the ambient impact analyses, and the evaluation of Project compliance with the applicable air quality regulations, including the MDAQMD's NSR requirements. These analyses are designed to confirm that the project's

design features lead to less-than-significant impacts even with the following conservative analysis assumptions and procedures: maximum allowable emission rates, project operating schedules that lead to maximum emissions, worst-case meteorological conditions, and adding the worst-observed existing air quality to the highest potential ground-level impact from modeling, even when all of these situations could not physically occur at the same time.

Emitting Units

The project comprises three identical 250 MW (nominal) plants: Plant 1 to the south, Plant 2 in the middle, Plant 3 to the north. The three solar plants will be constructed concurrently. The project also includes a common area. The relative locations of these areas are shown in Figure 2-2, Power Block Plot Plan, Section 2.0.

Each plant will include a power block with eight emitting units, consisting of five natural gas-fired boilers, two diesel fuel-fired emergency engines, and a wet surface air cooler. The Project also includes a common area with diesel fuel-fired emergency equipment consisting of a small emergency generator and a fire pump.

Three types of boilers will be used at each power block. Each boiler will be equipped with low-NO_x burners and flue gas recirculation (FGR) for NO_x control; CO will be controlled using good combustion practices; and particulate and VOC emissions will be minimized through the use of natural gas as the fuel. Specifications for the new boilers are summarized in Table 5.1-14.

To augment the solar output when solar energy diminishes or during transient cloudy conditions, each plant will utilize three 500 MMBtu/hr natural gas-fired auxiliary boilers, to be operated up to several hours on summer weekdays. The auxiliary boilers may also be used to extend daily power generation when there is not enough solar energy to fully utilize the solar boilers. Annual heat input to the auxiliary boilers will be limited to be less than 10 percent of annual solar energy capture.

Table 5.1-14
Natural Gas Boiler Specifications

	Auxiliary Boilers	Startup Boilers	Nighttime Preservation Boilers
Make & Model	Rentech or equivalent	Rentech or equivalent	Rentech or equivalent
Fuel	Natural gas	Natural gas	Natural gas
Maximum Boiler Heat Input Rate	500 MMBtu/hr @ HHV	249 MMBtu/hr @ HHV	15 MMBtu/hr @ HHV
Steam Production Rate	350,000 lb/hr	185,000 lb/hr	10,000 lb/hr
Stack Exhaust Temperature	406 °F	300 °F	300°F
Exhaust Flow Rate	167,000 acfm	74,100 acfm	5,800 acfm
Exhaust O2 Concentration, dry volume	3.0%	3.0%	3.0%

Table 5.1-14
Natural Gas Boiler Specifications

		Auxiliary Boilers	Startup Boilers	Nighttime Preservation Boilers
Exhaust CO2 Concentration, dry volume		10.2%	10.2%	10.2%
Exhaust Moisture Content, wet volume		16.3%	16.3%	16.3%
Emission Controls:	NOx	Low-NO_x Burners/FGR (9.0 ppmvd NO_x @ 3% O2)	Low-NOx Burners/FGR (9.0 ppmvd NO_x @ 3% O2)	Low-NOx Burners/FGR (9.0 ppmvd NO_x @ 3% O2)
	CO	Combustion controls (50 ppmvd @ 3% O2)	Combustion controls (25 ppmvd @ 3% O2)	Combustion controls (50 ppmvd @ 3% O2)
	VOC	Combustion controls (12.6 ppmvd @ 3% O2)	Combustion controls (12.6 ppmvd @ 3% O2)	Combustion controls (12.6 ppmvd @ 3% O2)

Each plant will use one 249 MMBtu/hr natural gas fired startup boiler to preheat the solar boiler and steam turbine generator piping before solar energy is available. This will enhance project efficiency by allowing solar flux to maximize output more quickly than if solar heating alone were used to preheat the entire system. During cloudy days or in case of emergency shutdown, the startup boilers may be used to keep the system hot to facilitate plant restart.

Finally, one small (15 MMBtu/hr) natural gas-fired boiler, called a nighttime preservation boiler, will be used at each plant to provide superheated steam to keep the steam turbine generators and boiler pump gland systems under vacuum overnight and during other shutdown periods when steam is not available. Using these small boilers will be more efficient than allowing these systems to cool and then using the larger startup boilers to reestablish the vacuums in the morning.

Table 5.15-15 presents the nominal fuel properties for the CPUC-regulated natural gas to be used by the boilers.

Each plant will also have one 2,500 kW diesel emergency generator at each power block to provide backup power to the facility in case of loss of line power; there will be one smaller 500 kW diesel emergency generator to provide emergency power to the common area (for a total of four engine generators). Specifications for these engine generators are provided in Table 5.1-16.

Table 5.1-15
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	Average Concentration, Volume	Constituent	Percent by Weight
CH_4	97.1%	C	73 %

Table 5.1-15
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	**Average Concentration, Volume**	**Constituent**	**Percent by Weight**
C_2H_6	1.3%	H	24 %
C_3H_8	0.2%	N	1 %
Iso-C_4H_{10}	0.04%	O	2 %
n-C_4H_{10}	0.04%	S	0.75 gr/100 scf
iso-C_5H_{12}	0.01%	Higher Heating Value	1,020 Btu/scf
n-C_5H_{12}	0.01%		22,840 Btu/lb
C_6+	0.01%		
N_2	0.30%		
CO_2	0.99%		
S	<0.0001%		
Total	100%		

Table 5.1-16
Emergency Generator Specifications

	Power Blocks (2 total)	Common Area
Make & Model	Caterpillar Gen. Set 2500 eKW or equivalent	Caterpillar Gen. Set 250 eKW or equivalent
EPA Cert	Tier 2	Tier 3
Fuel	CARB diesel	CARB diesel
Generator Rating, kW	2,500	250
Engine Rating, bhp	3,633	398
Fuel Consumption, gallons/hr	175	20
Stack Exhaust Temperature	925°F	855°F
Exhaust Flow Rate	19,600 acfm	2,250 acfm

One Diesel fire pump engine will be located in each power block as well as in the common area (total of four fire pump engines) to comply with fire codes. Typical specifications for these units are provided in Table 5.1-17.

Table 5.1-17
Specifications for the Diesel Fire Pump Engines

	Power Block Fire Pump Engines	Common Area Fire Pump Engine
Make & Model	Cummins CFP7E-F30 or equivalent	Cummins CFP5E-F30 or equivalent
EPA Cert	Tier 3	Tier 3
Fuel	CARB diesel	CARB Diesel
Engine Rating, bhp	200	125
Fuel Consumption, gallons/hr	12	8
Stack Exhaust Temperature	975°F	950°F
Exhaust Flow Rate	1,650 acfm	975 acfm

Diesel Fuel Supply and Storage

Diesel fuel for the emergency generators and fire pump engines will be stored in individual day tanks located adjacent to the units. The fire pump engine day tanks will be located in the individual fire pump houses. The diesel generator day tanks will be located in the generator skid bases. Diesel fuel consumption rates and diesel tank capacities are shown in Table 5.1-18.

Table 5.1-18
Maximum Diesel Fuel Use and Tank Capacities

Engine	Maximum Fuel Consumption Rate, gal/hr	Target Fuel Supply, Hours	Fuel Day Tank Capacity, gal
Emergency Diesel Generators, Power Blocks	175	9	1500
Emergency Diesel Generator, Common Area	40	13	500
Diesel Fire Pumps, Power Blocks	12	46	550
Diesel Fire Pump, Common Area	8	69	550

Diesel fuel for the mirror cleaning vehicles will be stored in an 8,000-gallon double-walled aboveground concrete storage tank. Nominal dimensions will be 23 feet long, 8 feet wide and 9 feet high.

The tanks are exempt from District permitting requirements per Rule 219.E.14.c (—Unheated storage of organic materials with an initial boiling point of 300 F or greater”).

Wet Surface Air Coolers

The main process steam cooling system will use dry cooling. The Applicant proposes to use one partial dry-cooling system (PDCS) in each power block for the auxiliary systems, including, but not limited to, generator and lube oil cooling for major equipment. The PDCS is a closed-loop two-stage cooling system. In this system, the heat will be rejected using ambient air in a dry cooling system, followed by a closed-loop evaporative fluid cooler for additional cooling at higher ambient temperatures. Under most conditions, all cooling will be provided by the dry portion of the cooling system. The wet portion is operated only when the ambient temperature is 86°F or higher.

The dry cooling portion of the PDCS has no air emissions. The wet portion of the PDCS will be a small wet surface air cooler (WSAC). A WSAC uses mechanical, induced-draft technology in a closed circuit. In the fluid cooler, the process fluid to be cooled is pumped through coils and cooling water passes over the coils, cooling the process fluid by evaporation. In this system, the cooling water does not contact the process fluid. Particulate emissions result from evaporation of the cooling water that drifts from the fluid cooler. Treated well water will be used for makeup water. The Total Dissolved Solids (TDS) level of the recirculating water is expected to be approximately 1,500 ppmw after concentration. High efficiency drift eliminators will help to minimize emissions from the WSACs. The WSACs are exempt from MDAQMD permit requirements per District Rule 219.E.4.c (exempting "[w]ater cooling towers…not used for evaporative cooling of process water…").

Oil-Water Separators and Evaporators

As discussed in Section 2.0, Project Description, the Project will include small oil-water separators and evaporators at each power block. General plant drains will collect containment area washdown, sample drains, and drainage from facility equipment drains. Water from these areas will be collected in a system of floor drains, hub drains, sumps, and piping and routed to the collection system. Drains that potentially could contain oil or grease will first be routed through the oil/water separators. Water passing through the oil/water separator will be reduced in volume by small thermal evaporators that will operate intermittently, using either electrical energy or steam.

The capacity of each oil-water separator will be 50 gallons per minute; however, the expected throughput, based on the water balance, is only 2 gallons per minute at each power block. The oil-water separators are exempt from permitting per District Rule 219.E.14.c (exempting "containers, reservoirs or tanks used exclusively for: … unheated storage of organic materials with an initial boiler point of 300 F or greater.")

5.1.4.2 Facility Operations

The auxiliary boilers will be operated mainly on weekdays during the peak summer months (June through September) to augment the solar operation when solar energy diminishes or during transient cloudy conditions when solar insolation alone is not sufficient to generate adequate steam for the steam turbines. The auxiliary boilers will be started each summer weekday at about 2:30 p.m. and heated up using intermittent gas burner firing. At about 3:00 p.m. the boilers will start to generate steam and the load will be increased at a rate dictated by the boiler manufacturer. The auxiliary boilers are expected to reach full capacity by 6:00 p.m. and will continue to operate at full load for several hours. In this operating mode, all three boilers at a plant would be started, loaded, and operated in the same manner. On cloudy days,

the auxiliary boilers may operate independently, depending upon steam requirements, and may operate more hours at different loads. One auxiliary boiler at each power block would be maintained on hot standby mode (with very low heat input to maintain full pressure and minimum steam flow), while the other boilers would be on warm standby (in which a boiler is periodically started and held at low fire until it returns to the warm standby temperature). NO_x emissions from the auxiliary boilers will be continuously monitored to ensure that daily NO_x emissions remain below 25 pounds per day per boiler. The auxiliary boilers are not expected to operate between October and May. Maximum annual auxiliary boiler use will be the equivalent of approximately 200 full-load hours per year per boiler. Heat input from natural gas will be limited to below 15 percent of the heat input from the sun, on an annual basis.

The startup boilers will be operated up to two hours per day in the morning to warm the main steam systems before solar energy is available to the solar boilers. During cloudy days or in case of emergency shutdown of the solar boilers, the startup boilers may be used to keep the system hot to facilitate plant restart. Daily maximum impacts from boiler operations were calculated assuming that each boiler would be fired up to two hours at full load on any given day.

The nighttime preservation boilers will operate up to 12 hours per day (8 to 10 hours during the summer months, more during the winter months) to maintain system temperatures overnight.

Maximum annual startup boiler use will be the equivalent of approximately 800 full-load hours per year per boiler; maximum annual nighttime boiler operation will be the equivalent of approximately 4,036 full-load hours per year per boiler. The annual operating schedule is summarized in Table 5.1B-8, Appendix 5.1B.

Boiler heat inputs, as summarized in Table 5.1-14, correspond to the proposed individual unit emission limits. The daily and annual natural gas fuel use corresponding to the operating schedule described above are shown in Table 5.1-19: hourly heat input to each unit, total combined daily heat input to all units at the three plants, and total combined annual heat input to the three plants.

Emission rates and operating parameters for the boilers are shown in Appendix 5.1B, Tables 5.1B-1, B-2 and B-3. Emission rates and operating parameters for the emergency engines are shown in Appendix 5.1B, Tables 5.1B-4 and B-5. Emission rates and operating parameters for the fire pump engines are shown in Appendix 5.1B, Tables 5.1B-6 and B-7. The daily and annual fuel use levels are based on the daily/annual boiler operating hours shown in Appendix 5.1B, Table 5.1B-11.

Table 5.1-19
Maximum Facility Natural Gas Fuel Use, Boilers (MMBtu)[a]

Period	Auxiliary Boilers	Startup Boilers	Nighttime Preservation Boilers	Total Fuel Use (all boilers)
Per Hour (each unit)	500	249	15	--
Per Day (total, all units)	18,000	1,494	360	19,854
Per Year (total, all units)	900,000	597,600	181,620	1,679,220

Notes:
[a] MMBtu: million Btu

Emergency engines will be tested to ensure that they will function when needed. In order to provide maximum flexibility, it was assumed that each engine would use the 50 hours of testing allowed under the state stationary engine Airborne Toxics Control Measure (ATCM) plus an additional 150 hours per year of emergency operation.[2] It was also assumed that as a worst case, all of the emergency generator and fire pump engines would be tested at the same time. The engines would not be tested on days when the auxiliary boilers are operating. Combined annual fuel use in all engines, as shown in Table 5.1-20, will be limited by permit condition.

Table 5.1-20
Maximum Facility Diesel Fuel Use, Engines (MMBtu)[a]

Period	Power Block Emergency Engines	Common Area Emergency Engine	Power Block Fire Pump Engines	Common Area Fire Pump Engine	Total Fuel Use (all engines)
Per Hour (each unit)[b]	11.9	1.4	0.8	0.6	--
Per Day (total, all units)	35.7	1.4	2.4	0.6	40.1
Per Year (total, all units)	14,280	544	979	218	16,021

Notes:
[a] MMBtu: million Btu
[b] Based on 30-minute test operations.

As discussed above, the main process steam will be cooled using a dry cooling system. A PDCS will be used in each power block for auxiliary system cooling, including but not limited to lube and seal oil cooling for major equipment, and chemical feed system cooling requirements. Only the WSAC portion

[2] For annual criteria pollutant emissions calculations, emergency engine operation was limited to 50 hours/year to match the limit in the ATCM for operation for maintenance/testing purposes. However, for the calculation of annual greenhouse gas emissions, engine emergency operations must be included (see Section 5.1.4.5.5, Greenhouse Gas Emissions).

of the cooling system will have air emissions, and that portion of the cooling system is expected to operate only under high ambient temperature conditions.

5.1.4.3 Emissions Calculations

This section presents calculations of emissions increases from the proposed new boilers and engines. Tables containing the detailed calculations are included in Appendix 5.1B.

Criteria Pollutant Emissions: Combustion Equipment

The boilers, emergency engines, and Diesel fire pump engine emission rates have been calculated from data provided by the project engineering firm, project design criteria, and established emission calculation procedures. The emission rates for the boilers are shown in the following tables. The emission rates for the Diesel emergency and fire pump engines are shown in Tables 5.1B-4 through B-7 of Appendix 5.1B.

Boiler Emissions during Normal Operations

Emissions of NOx, CO, VOC, and SOx were calculated from the heat input (in MMBtu) and emission limits (in lbs/MMBtu). The NO_x emission limit reflects the use of low-NO_x burners and flue gas recirculation. The SOx emission factor of 0.0021 lb/MMBtu was derived from the maximum allowable (i.e., CPUC-approved tariff limit) fuel sulfur content of 0.75 grains per 100 standard cubic feet (gr/100 scf). Maximum emissions are based on the highest heat input rates shown in Table 5.1-14.

The VOC and CO emission limits reflect the use of good combustion practices. SOx, PM_{10}, and $PM_{2.5}$ emission rates are based on the use of natural gas as the fuel and good combustion practices.

Maximum hourly PM_{10} emissions are based on design specifications. $PM_{2.5}$ emissions were determined based on the assumption that all boiler exhaust particulate is less than 2.5 microns in diameter.

Emissions for the boilers are summarized in Table 5.1-21. The auxiliary and startup boilers are expected to have a 4:1 turndown ratio; the nighttime preservation boilers are expected to have a 5:1 turndown ratio. Full-load emission rates will be achieved throughout the turndown range. Emissions during other activities are discussed in more detail below.

Table 5.1-21
Maximum Hourly Emission Rates: Boilers, Normal Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
Auxiliary Boilers (each)			
NOx	9.0	0.011	5.5
SO2[a]	1.7	0.002	1.1
CO	50	0.037	18.7
VOC	12.6	0.0054	2.7

Table 5.1-21
Maximum Hourly Emission Rates: Boilers, Normal Operations

Pollutant	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
$PM_{10}/PM_{2.5}$	n/a	0.005	2.5
Startup Boilers (each)			
NOx	9.0	0.011	2.7
SO2[a]	1.7	0.002	0.5
CO	25	0.018	4.7
VOC	12.6	0.0054	1.3
$PM_{10}/PM_{2.5}$	n/a	0.005	1.25
Nighttime Preservation Boilers (each)			
NOx	9.0	0.011	0.17
SO2[a]	1.7	0.002	0.03
CO	50	0.037	0.55
VOC	12.6	0.0054	0.08
$PM_{10}/PM_{2.5}$	n/a	0.005	0.08

Notes:
[a] Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Auxiliary Boiler Emissions During Hot/Warm Standby

During cloudy conditions, when solar energy is not sufficient to keep the steam turbine online, the auxiliary boilers will be kept in warm or hot standby mode to allow them to ramp up to operating pressure within about 30 minutes. In hot stand-by, a boiler is maintained at full pressure with minimum steam flow by firing at up to about 5 percent of rated heat input. In warm standby, a boiler is periodically started and held at low fire until it returns to a preset warm standby temperature. Because of the extremely low heat input experienced during these modes, combustion is less efficient and NOx, VOC, CO, and PM_{10} emission concentrations are elevated. However, hourly mass emission rates during these standby modes will be lower than full load emission rates because of the extremely low heat input rate. Hourly emission rates for the auxiliary boilers during hot standby are summarized in Table 5.1-22. Hourly emission rates for the boilers during warm standby operations will be even lower because firing will be intermittent.

Table 5.1-22
Maximum Hourly Emission Rates: Auxiliary Boilers, Hot/Warm Standby Operations

Pollutant	ppmvd @ 3% O2	lb/MMBtu	lb/hr
Auxiliary Boilers (each)			
NOx	100	0.12	3.0
SO2[a]	1.7	0.002	0.05
CO	250	0.18	4.6
VOC	25	0.0105	0.3
$PM_{10}/PM_{2.5}$	n/a	0.01	0.25

Note:
[a] Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Boiler Emissions During Startup/Shutdown

The auxiliary boilers may require up to 6 hours to achieve permitted emission limits (at 25 percent load) after an extended period of shutdown (cold start). The startup boilers may require up to 5 hours to achieve permitted limits, while the nighttime preservation boilers are expected to require less than 4 hours. Emissions during cold startup of each boiler were calculated assuming an average heat input rate over the startup period equivalent to half the minimum load (12.5 percent of maximum hourly heat input for the auxiliary and startup boilers and 10 percent of maximum hourly heat input for the nighttime preservation boilers). Expected emissions during a cold startup of the auxiliary and startup boilers are shown in Table 5.1-23; startup emissions for the nighttime preservation boilers are shown in Table 5.1-24. Emissions were calculated assuming that only one auxiliary or nighttime preservation boiler at each plant will be in cold startup at a time, and a boiler would require the full number of hours for startup and have the emissions shown only when other boilers are not operating and available to provide preheat steam. The startup boilers may undergo a cold startup when the nighttime preservation boilers are in operation.

A cold startup of an auxiliary boiler is expected to occur about once every 2 weeks during the summer season. Based on 4 months of expected summertime operation, a cold startup of an auxiliary boiler would occur about 8 times per year. To minimize daily emissions, the cold startup of an auxiliary boiler will be staged over a two-day period. Because the startup and nighttime preservation boilers will operate year-round, cold startups of these boilers would be expected to occur about every 4 weeks, or approximately 13 times per year.

Table 5.1-23
Maximum Hourly Emission Rates: Auxiliary and Startup Boilers, Startup Operations

Pollutant	ppmvd @ 3% O2	lb/MMBtu	Auxiliary Boiler lb/hr	Startup Boiler lb/hr
NOx	75	0.09	5.6	2.8
SO2[a]	1.7	0.002	0.13	0.07
CO	300	0.22	13.7	6.8
VOC	60	0.025	1.6	0.8
$PM_{10}/PM_{2.5}$	n/a	0.01	0.63	0.31

Notes:
[a] Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Table 5.1-24
Maximum Hourly Emission Rates: Nighttime Preservation Boilers, Startup Operations

Pollutant	ppmvd @ 3% O2	lb/MMBtu	lb/hr
NOx	70	0.084	0.13
SO2[a]	1.7	0.002	0.003
CO	275	0.20	0.31
VOC	55	0.023	0.04
$PM_{10}/PM_{2.5}$	n/a	0.01	0.02

Notes:
[a] Based on maximum natural gas sulfur content of 0.75 grains/100 scf.

Hourly NO_x emissions during cold startup of the auxiliary and startup boilers are expected to be slightly higher than hourly emissions during normal operation. Hourly CO emissions from the startup boiler may also be higher during cold startup than during normal operation.

During routine daily startups, emissions concentrations may be higher than those shown for normal operations in Table 5.1-21 until each boiler reaches its minimum compliant load (25 percent of rated load for the auxiliary and startup boilers; 20 percent of rated load for the nighttime preservation boilers). However, because of the shorter startup times and low heat input rates, the boilers are expected to comply with the pound per hour emission rates on a 3-hour average basis during these routine daily startups.

Boiler Operations During Commissioning Activities

During plant commissioning, emissions will be elevated during the first several days of operation of each boiler as it is started up and held at low loads for tuning. Expected emissions during boiler commissioning activities are shown in Table 5.1B-17, Appendix 5.1B. Only one boiler at a time will be undergoing commissioning activities.

Criteria Pollutant Emissions: Wet Surface Air Coolers

The dry cooling portion of the PDCS has no air emissions. The wet portion of each cooling system emits only water vapor and will be equipped with a 4,000 gallons per minute (gpm) WSAC. Particulate emissions result from evaporation of the cooling water that drifts from the fluid cooler.

Treated well water will be used for makeup water, and the Total Dissolved Solids (TDS) level of the recirculating water is expected to be approximately 1,500 ppmw after concentration.

Details of the cooling water drift calculation for the WSACs are shown in Appendix 5.1B, Table 5.1B-9. Particulate emissions from each cooling system will be about 40 pounds per year.

Criteria Pollutant Emissions: Mirror Cleaning

Mirror washing will employ a high-pressure system using treated water, by means of vehicle-towed trailers that contain a water tank, positive displacement water pumps that deliver water at high-pressure, and spray nozzles operated by the cleaning crew. The washing is expected to be done on a 2-week rotating cycle. The water washing will be supplemented with brushing, which will be done on an 8-week schedule.

Each solar field is divided into three zones for the purpose of heliostat cleaning, depending upon the locations and density of heliostat placement. These zones determine what type of mirror washing machine can be used for the heliostats in the zone. The Near Tower Zone (NTZ) consists of the area closest to the tower. The layout in this zone allows a vehicle to drive between the heliostats so that each heliostat can be accessed directly. The NTZ mirror washing machines are small and maneuverable. Each solar plant will require four NTZ mirror washing machines.

Heliostats beyond the Near Tower Zone cannot be accessed directly and must be reached with a crane. The heliostats that are more than about 400 meters from the tower will be cleaned using tractor-towed trailers with telescoping arms that can reach the heliostats from the limited areas in which vehicles can drive. Each machine will drive a short distance, park and anchor, and then extend its crane arm to clean as many heliostats as can be reached from its location. Each solar plant will require a total of 17 tractor-pulled trailers for cleaning heliostats outside the NTZ.

Two components contribute to emissions from site maintenance activities: combustion emissions from vehicles, and fugitive dust from driving over unpaved surfaces. Calculations of emissions from mirror cleaning activities are shown in Appendix 5.1B, Table 5.1B-10 and are summarized in Table 5.1-25 below.

Table 5.1-25
Emissions from Mirror Cleaning Activities

	Pollutant						
	NOx	SO2	CO	VOC	PM_{10}	$PM_{2.5}$	DPM
Hourly, lb/hr	10.7	0.19	3.1	5.1	2.9	0.6	0.4
Daily, lb/day	112.3	2.0	33.0	53.5	30.5	6.4	3.7
Annual, ton/yr	20.5	0.37	6.0	9.8	5.6	1.2	0.7

Criteria Pollutant Emissions: Plant Operation

The calculation of maximum facility emissions shown in Table 5.1-26 is based on the boiler emission rates shown in Table 5.1-21, the fuel use levels in Table 5.1-19, and the following assumptions:

- Although the auxiliary, startup and nighttime preservation boilers are unlikely to be operated at the same time, a worst-case assumption is that boiler operations occur simultaneously.
- Each engine may be operated for maintenance and testing for up to 30 minutes on a single day and up to 50 hours per year. Although it is highly unlikely that all engines will be tested at the same time, the analysis of maximum hourly emissions during emergency engine testing assumes that all of the engines may be tested at the same time. Engines will not be tested on a day when the auxiliary boilers are operating.

Mirror cleaning will occur at night and will overlap only with operation of the nighttime preservation boilers.

Hourly, daily, and annual emissions from the new facility are shown in Appendix 5.1B, Table 5.1B-11. The maximum hourly, daily, and annual emissions, summarized in Table 5.1-26, are used in the air dispersion modeling to calculate the maximum potential ground-level concentrations contributed by the project to the ambient air.

Greenhouse Gas Emissions

Direct emissions of GHGs from the Project are presented in Table 5.1-27. with the detailed GHG calculations included in Appendix 5.1B, Table 5.1B-12. Carbon dioxide, nitrous oxide, and methane emissions are based on default emission factors for boilers and reciprocating internal combustion engines in the California Air Resources Board GHG Reporting Regulation.[3] The estimated emissions include sulfur hexafluoride leakage emissions from six circuit breakers at the switchyard (five in use, one in storage) and one Generator Circuit Breaker (GCB) at each power block. Emissions of methane, nitrous

[3] CARB, *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Appendix A*, December 2007

oxide, and sulfur hexafluoride have been converted to carbon dioxide equivalents using GHG warming potentials of 21, 310, and 23,900, respectively.

When calculating criteria pollutant emissions from the emergency generators, only the allowable hours per year of operation for testing and maintenance are used to determine maximum annual emissions; emergency use is not considered.[4] However, EPA guidance for determining potential to emit from emergency engines requires the inclusion of all operations: "EPA has no policy that specifically requires exclusion of 'emergency'… emissions."[5] In the absence of any permit limitation on annual emissions, EPA "believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions."[6] Therefore, in the absence of any limiting permit condition, the calculation of PTE for GHG would have to assume that each emergency engine and fire pump engine will operate for 500 hours per year. The Applicant believes that operation of the emergency equipment will in fact not exceed 200 hours per year and is proposing an annual combined fuel use limit, equivalent to 200 hours per year of full-load operation of each unit, that will limit the GHG potential to emit for the emergency units and ensure that GHG emissions from the facility will be less than 100,000 tpy. As discussed in Section 5.1.5.2, for facility-wide annual criteria pollutant emissions calculations, engine operation was limited to 50 hours/year to match the limit in the ATCM for operation for maintenance/testing purposes.

[4] CARB, *Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled* Engines, October 2000; Footnote 3 to Table 1, Permitting Requirements for New Stationary Diesel-Fueled Engines ("The annual hours of operation for emergency standby engines include the hours of operation for maintenance and testing runs only.")

[5] EPA, Letter from Steven C. Riva, Chief, Permitting Section, Air Programs Branch, to William O'Sullivan, Director, Division of Air Quality, New Jersey Department of Environmental Protection, February 14, 2006.

[6] EPA, Memorandum from John S. Seitz, Director, OAQPS, to Regional Directors, re: "Calculating Potential to Emit (PTE) for Emergency Generators," September 6, 1995.

Table 5.1-26
Maximum Emissions from New Equipment

	Pollutant				
Emissions/Equipment	**NOx**	**SO_2**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**
Maximum Hourly Emissions[a]					
Boilers	58.2	11.1	179.8	28.6	26.5
Emergency Engines	59.0	0.06	32.3	2.1	1.9
Diesel Fire Pump Engines	2.4	<0.01	2.2	0.1	0.1
WSACs	--	--	--	--	<0.01
Total, pounds per hour	61.4	11.1	179.8	28.6	26.5
Maximum Daily Emissions[b]					
Boilers	260.4	42.8	801.2	118.9	104.0
Emergency Engines	59.0	0.06	32.3	2.1	1.9
Diesel Fire Pump Engines	2.4	<0.01	2.2	0.1	0.1
WSACs	--	--	--	--	0.5
Total, pounds per day	260.4	42.8	801.2	118.9	104.5
Maximum Annual Emissions					
Boilers	10.8	1.8	28.8	5.0	4.4
Emergency Engines	2.9	<0.01	1.7	0.1	0.1
Diesel Fire Pump Engines	0.1	<0.01	0.1	0.01	0.01
WSACs	--	--	--	--	0.04
Total, tons per year	13.8	1.8	30.6	5.1	4.5

Notes:
[a] Boilers and engines will not operate during the same hour (see Table 5.1B-11, Appendix 5.1B). Maximum hourly emissions occur during boiler operations.

[b] Engine testing will occur only on days when the auxiliary boilers do not operate (see Table 5.1B-11, Appendix 5.1B). Maximum daily emissions occur on a day when the startup boilers undergo cold startup.

Table 5.1-27
Annual Emissions of Greenhouse Gases (GHGs)

Pollutant	Emissions (metric ton/year)	CO2 Equivalent (metric ton/yr)	CO2 Equivalent (tons/yr)
CO_2	89,951	89,951	--
Nitrous Oxide	0.2	55.0	--
Methane	1.6	32.8	--
SF6	3.0x10-3	71.7	--
Total	--	90,111	99,122

Evaluation of Potential PSD Applicability

For the purposes of determining applicability of the PSD program requirements, the following regulatory procedure is used. Project emissions are compared with regulatory significance thresholds to determine whether the facility is major and thus may be subject to PSD review. If the facility emissions exceed these thresholds, it is a major facility. The comparison in Table 5.1-28 indicates that the Project would not be a major source because its emissions of all pollutants are below the applicable major source thresholds.

Table 5.1-28
Comparison of Project Emissions With PSD Major Source Thresholds

Pollutant	Maximum Annual Project Emissions (tpy)	PSD Major Source Threshold (tpy)	Is Facility a Major Source?
NO_2	13.8	100	No
SO_2	1.8	100	No
CO	30.6	100	No
VOC	5.1	100	No
PM_{10}	4.5	100	No
$PM_{2.5}$	4.5	100	No
CO_2e	99,122	100,000	No

Non-Criteria Pollutant Emissions

Maximum hourly and annual noncriteria pollutant (TAC) emissions were estimated for the proposed boilers, emergency generators, emergency fire pumps, and partial dry cooling systems (WSACs).

Maximum proposed TAC emissions for the boilers are shown in Table 5.1-29, and were calculated from the heat input rates (in MMBtu/hr and MMBtu/yr) shown in Table 5.1-19 and Table 5.1-20, EPA emission factors (in lb/MMscf), and the nominal higher heating value for the natural gas of 1020 Btu/scf.

Because Diesel particulate matter is regulated by the State of California as a TAC, all of the PM_{10} emissions from the Diesel emergency engines and Diesel fire pump engines are also included. (These are shown in Table 5.1-17, with supporting calculations shown in Appendix 5.1B, Tables 5.1B-4 through B-7.) The ambient impact of these non-criteria pollutant emissions is determined by the potential health risks calculated in the screening health risk assessment (see Section 5.1.4.6).

Detailed calculations of the TAC emissions from the facility are shown in Appendix 5.1B, Tables 5.1B-14 and 5.1B-15. Toxic air contaminant emissions from the WSACs are negligible, as shown in Table 5.1B-16 of Appendix 5.1B.

Table 5.1-29
Summary of Toxic Air Contaminant (TAC) Emissions from Project Operation

Compound	Maximum Proposed Emissions (total, all units)	
	lb/hr	tpy
Boilers[a]		
Acetaldehyde	4.8×10^{-3}	9.5×10^{-4}
Acrolein	4.2×10^{-3}	8.4×10^{-4}
Benzene	9.0×10^{-3}	1.8×10^{-3}
Ethylbenzene	1.1×10^{-2}	2.1×10^{-3}
Formaldehyde	1.9×10^{-2}	3.8×10^{-3}
Hexane	6.9×10^{-3}	1.4×10^{-3}
Naphthalene	1.6×10^{-3}	2.5×10^{-4}
Polycyclic Aromatics	5.2×10^{-4}	8.4×10^{-5}
Propylene	1.0×10^{-1}	5.9×10^{-2}
Toluene	4.1×10^{-2}	8.2×10^{-3}
Xylene	3.1×10^{-2}	6.1×10^{-2}
Emergency Engines[b]		
Diesel Particulate Matter	1.9	9.3×10^{-2}
Fire Pump Engines[b]		
Diesel Particulate Matter	0.1	7.0×10^{-3}
Mirror Cleaning[c]		
Diesel Particulate Matter	0.4	0.7
Total HAPs[d]		2.6×10^{-2}

Notes:
[a] Emission factors obtained from Ventura County APCD. See Appendix 5.1B, Tables 5.1B-13 through 5.1B-15.
[b] All PM_{10} emissions from Diesel engines are TACs.
[c] From Table .
[d] Propylene and Diesel Particulate Matter are not HAPs.

As emissions of each individual federally regulated HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the project is an area source of HAPs. Compliance with the applicable NESHAPs is discussed in Section 5.1.6.1.

Construction Emissions: Project Construction

Rio Mesa SEGF is comprised of three power blocks. All power blocks will be constructed at the same time, over a 36-month period.

There are two types of construction emissions: combustion emissions and fugitive dust. Combustion emissions come from the workers‘ vehicles, from heavy equipment (both stationary and mobile), and from delivery vehicles. Fugitive dust comes from moving, disturbing, and traveling over the work site and roads and from windblown dust sources. Other activities that create dust include scraping and grading of the site, earth moving, and the movement of various construction vehicles around the site. Two concrete batch plants will also be operated for about 21 months of the 36-month construction period. Although emissions from the batch plants will be minimized by powering the equipment with electric power instead of diesel-powered generators, the transfer activities will be a potential source of fugitive dust.

The construction schedule is broken down into several activities: mobilization, during which the sites are set up to support the equipment and workers that will be on the site; clear and grub and road construction, during which vegetation is removed from the heliostat fields, the terrain is smoothed (not, however, graded, except for the power block areas), and plant and heliostat field access roads are constructed; heliostat erection; and power block, tower and dry cooling system (air-cooled condenser) erection. Commissioning and testing will begin at the end of the construction period, when heliostat erection and power block construction are complete. Estimated land disturbance for major construction activities is summarized in Section 2.0, Project Description.

Construction equipment and vehicle exhaust emissions were estimated using equipment lists and construction scheduling information provided by the project design engineering firm, which are presented in Section 2.0, Project Description, and Appendix 5.1F. CARB‘s OFFROAD2007 and EMFAC2007 models were used to generate equipment-specific emission factors for all criteria pollutants for diesel-fueled construction equipment and for on-road vehicles, respectively. Assumptions used in calculating project construction emissions included a 36-month construction period with 5 construction days per week. Double-shift work schedules will be used during solar field assembly and installation activities and construction activities will continue around the clock when concrete is poured for the solar towers. A single-shift, 8- to 10-hour workday will be used for the remainder of the construction activities. The list of fueled equipment needed during each month of the construction effort (see Appendix 5.1F, Attachment 5.1F-1) served as the basis for estimating pollutant emissions throughout the term of construction and helped to identify the periods of probable maximum short-term emissions.

Fugitive dust emissions resulting from on-site soil disturbances were estimated using EPA AP-42 emission factors for activities including bulldozing and dirt-pushing, travel on paved and unpaved roads, material handling, and wind erosion to storage of aggregate materials. The mitigation measures of frequent watering and limiting speeds to 15 miles per hour were assumed to achieve a combined dust control efficiency of 85 percent for traveling on unpaved surfaces at the project site and temporary

construction area activities. Emissions from on-road delivery trucks and worker commute trips were estimated using trip generation information presented in Section 5.12, Traffic and Transportation, and emission factors provided by CARB's EMFAC2007 model.

The short-term maximum emissions were calculated using Month 15 for construction equipment and Month 12 for fugitive dust. Annual emissions were based on the worst 12 consecutive months of the construction period.

Detailed construction emissions calculations are provided in Appendix 5.1F. Maximum daily project construction emissions are summarized in Table 5.1-30. Maximum annual project construction emissions are summarized in Table 5.1-31.

Table 5.1-30
Maximum Daily Project Construction Emissions, Pounds Per Day, Month 15 (Combustion), Month 12 (Fugitive Dust)

	NO_x	CO	VOC	SO_x	PM_{10}	$PM_{2.5}$
Onsite						
Construction Equipment (including batch plant)	220.0	120.9	22.0	0.5	13.2	11.5
Fugitive Dust	--	--	--	--	136.5	17.4
Offsite						
Worker Travel, Truck Deliveries	754.7	872.1	118.5	1.1	39.0	31.1
Total	974.7	993.0	140.5	1.6	188.7	60.0

Table 5.1-31
Maximum Annual Onsite Construction Emissions, Tons Per Year

	NO_x	CO	VOC	SO_x	PM_{10}	$PM_{2.5}$	GHG[a]
Onsite							
Construction Equipment	25.7	14.2	2.6	0.1	1.3	1.3	5,518
Fugitive Dust	--	--	--	--	13.0	1.8	--
Offsite							
Worker Travel, Truck Deliveries	74.6	99.1	12.8	0.1	3.9	3.1	7,144
Total	100.3	113.3	15.4	0.2	18.2	6.2	12,662

Notes:
[a] GHG emissions shown as total MT for construction period.
GHG = greenhouse gases.

Construction Emissions: Linears

Rio Mesa SEGF will require an approximately 10-mile-long transmission line to connect the project to the electrical grid. The transmission line will originate at the project's onsite switchyard and head north to a new substation that will be constructed by SCE (CRS). Natural gas will be supplied to the proposed project by connecting to the TransCanada Gas Transmission Company's North Baja pipeline, which runs adjacent to the eastern edge of the solar fields. Because the natural gas supply pipeline is located towards the edge of the solar field, the natural gas tie in construction emissions are included with the power plant construction emission calculations.

Transmission line construction activities will include clearing rights-of-way, laydown areas and temporary equipment storage yards; building new temporary and permanent access roads; installing transmission structures; and conductor pulling. Some blasting may be required in rocky terrain.

Construction of the new transmission line will require approximately 4 months. Calculations of offsite construction emissions are provided in Appendix 5.1F. Expected daily transmission construction emissions are summarized in Table 5.1-32. Annual emissions from construction of linears are summarized in Table 5.1-33.

Table 5.1-32
Expected Daily Transmission Line Construction Emissions, Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}	$PM_{2.5}$
Construction Equipment	181.8	113.6	14.1	0.3	7.9	7.9
Fugitive Dust	--	--	--	--	130.1	12.9
Worker Travel	21.5	20.8	3.0	0.03	1.1	0.9
Total	203.3	134.4	17.1	0.3	139.1	21.7

Table 5.1-33
Transmission Line Construction Emissions, Tons Per Year

	NO_x	CO	VOC	SO_x	PM_{10}	$PM_{2.5}$	GHG
Construction Equipment	4.9	3.1	0.4	0.01	0.2	0.2	287
Fugitive Dust	--	--	--	--	2.8	0.3	--
Worker Travel	0.3	0.3	0.0	0.00	0.02	0.01	62
Total	5.2	3.4	0.4	0.01	3.0	0.5	349

Note:
GHG = greenhouse gases; units are total MT for the construction period.

5.1.4.4 Emissions and Fuel Use Monitoring

The auxiliary boilers will be equipped with continuous emissions monitoring systems (CEMS) to measure and record emissions of NO_x and O_2, as required under 40 CFR Parts 60 and 75. The fuel flow rate (in MMscf) and oxygen levels for each of the boilers will be monitored continuously and permanently recorded.

For the startup boilers, NO_x emissions will be monitored using a predictive monitoring system (PEMS), as required under 40 CFR Part 60. This system will also monitor and permanently record fuel use. The nighttime preservation boilers will monitor and record fuel use. Vendor supplied emission factors will be used to calculate nighttime preservation boiler emissions based on fuel use data. Operating hours and fuel use will also be monitored and recorded for each of the emergency diesel engines and fire pump engines.

5.1.4.5 Air Quality Impact Analysis

The air quality impact analysis for the Project evaluates the emissions presented above in ambient air dispersion modeling and health risk assessments. These analyses are presented in this section.

Air Quality Modeling Methodology

An assessment of impacts from the Project on ambient air quality was conducted using EPA-approved air quality dispersion models. These models use a mathematical description of atmospheric dispersion to simulate the actual processes by which emissions are transported to potential ground-level impact areas. A detailed description of the methodology is provided in the Ambient Air Quality Modeling Protocol and follow-up correspondence with the MDAQMD and CEC staffs, which are included as Appendix 5.1H.

Using conservative assumptions, dispersion modeling was used to determine the maximum ground-level impacts of the Project. The results were compared with state and federal ambient air quality standards. If the standards are not exceeded in the analysis, then the facility will cause no exceedances under any operating or ambient conditions, at any location, under any meteorological conditions. In accordance with the air quality impact analysis guidelines developed by EPA[7] and CARB,[8] the ground-level impact analysis includes the following assessments:

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

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that would limit the amount of final plume rise. Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions.

[7] EPA. Guideline on Air Quality Models, 40 CFR Part 51, Appendix W.
[8] ARB. Reference Document for California Statewide Modeling Guideline, April 1989.

Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. Downwash can occur when wind speeds are high and a sufficiently tall building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee (downwind) side of the building or structure.

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

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

$$C\ x,y,z,H = \frac{Q}{2\pi\sigma_y\sigma_z u} * e^{-1/2\ y\ \sigma y\ ^2} * e^{-1/2\ z-H/\sigma_z\ ^2} + e^{-1/2\ z+H/\sigma_z\ ^2}$$

Where:

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

Q = the pollutant emission rate

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

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

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

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

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

- Model selection;
- Refined air quality impact analysis;

- Existing ambient pollutant concentrations and preconstruction monitoring; and
- Results of the ambient air quality modeling analyses.

Model Selection

The air quality impact analyses were performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (current version 11103). The AERMOD model is a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground elevations can exceed the stack heights of the emission sources (i.e., complex terrain). The model is capable of estimating concentrations for a wide range of averaging times (from 1 hour to 1 year). Inputs required by the AERMOD model include the following:

- Model options;
- Meteorological data;
- Source data; and
- Receptor data.

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

AERMOD uses hourly meteorological data to characterize plume dispersion. The representativeness of the data is dependent on the proximity of the meteorological monitoring site to the area under consideration, the complexity of the terrain, the exposure of the meteorological monitoring site, and the period of time during which the data are collected. The meteorological data set used in this analysis combined surface meteorological data (e.g., wind speed and direction, temperature) from the Blythe Airport, monitoring station, surface data (cloud cover) from the McCarran Airport in Las Vegas, NV, and upper air data from Tucson, AZ.

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

$$H_g = H + 1.5L$$

Where:

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

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

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

The boiler stack heights, at between 35 and 135 feet, are less than the GEP limit of 65 meters (213 feet). Stack heights therefore do not need to be adjusted for GEP.

Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from U.S. Geological Survey (USGS) National Elevation Dataset (NED) data in the GeoTIFF format at a horizontal resolution of 1 arc-second (approximately 30 meters). All coordinates were referenced to UTM North American Datum 1983 (NAD83), Zone 11. The AERMOD receptor elevations were interpolated among the Digital Elevation Map (DEM) nodes according to standard AERMAP procedures. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option was chosen; hills were not imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids were used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid was developed and extended outwards at least 5 km.[9] For the full impact analyses, a nested grid was developed to fully represent the maximum impact area(s). This grid has 25-meter resolution along the facility fence-line in a single tier of receptors composed of four segments extending out to 100 meters from the fenceline, 100-meter resolution from 100 meters to 1,000 meters from the fenceline, and 250-meter spacing out to 5 km from the fenceline,. Additional refined receptor grids with 25-meter resolution were placed around the maximum first-high and maximum second-high coarse grid impacts and extended out 500 meters in all directions. Concentrations within the facility fenceline were not calculated. The regions imported in Geographical Coordinates for the USGS NED data are bounded as follows:

- South West corner: UTM Zone 11 (NAD 83) 690000.0 m, 3700000.0 m; and
- North East corner: UTM Zone 11 (NAD 83) 730000.0 m, 3740000.0 m.

Meteorological Data Selection

EPA defines the term ―onsite data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality.

[9] Although the modeling protocol indicated that the coarse receptor grid would extend up to 10 km from the fenceline, the maximum impacts were very close to the project and a larger grid was not needed to identify significant impact areas.

Representativeness has been defined in the PSD Monitoring Guideline as data that characterize the air quality for the general area in which the proposed project would be constructed and operated. The meteorological data requirement originates in the Clean Air Act at §165(e)(1), which requires an analysis —of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of on-site monitoring data are also outlined in the On-Site Meteorological Program Guidance for Regulatory Modeling Applications.[10] The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected.

Hourly surface meteorological data (e.g., hourly wind speed and direction, temperature) have been obtained from the Blythe Airport for calendar years 2006 through 2010. Cloud cover data from the McCarran Airport, near Las Vegas, were used as no cloud cover data are collected at the Blythe station. Upper air data were recorded at Tucson, AZ. The Blythe monitoring station is approximately 6 miles (10 km) from the project site, and is located at a similar elevation on the same high desert plateau. Therefore, the met data station meets criteria (a), (b) and (c) above. In addition, the use of five years of meteorological data ensures adequate representation of temporal variation. Based on these considerations, the applicant believes that the proposed meteorological data are representative of conditions at the project site.

Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Blythe meteorological monitoring station. The Blythe meteorological monitoring station is in close proximity to the proposed project site (distance between the two locations is approximately 6 miles with no significant intervening terrain features), and the same large-scale topographic features located to the east and south that influence the meteorological data monitoring station influence the proposed project site in the same manner.

The values for the surface characteristics of albedo, Bowen Ratio, and surface roughness appropriate to the area around the Blythe Airport meteorological monitoring station have been obtained from AERSURFACE, designed to aid in obtaining realistic and reproducible surface characteristic values for AERMET, following EPA guidance. AERSURFACE uses land cover data from the USGS National Land Cover Data 1992 archives, meaning that the land cover data used to develop surface characteristics for the Blythe Airport area reflect conditions in 1992, before development took place in the area. The area within one kilometer of the met station, which is used in the AERMOD model to define surface characteristics, has seen some isolated development to the southwest, southeast, and east. The rest of the area surrounding the met station remains undeveloped. The prevailing winds in the area are from the south through southwest, so only the development to the south would be likely to have any significant influence on meteorological conditions monitored at the station. Because of the sparse distribution and the regular shapes of these buildings, the impacts of these buildings on the monitor are expected to be

[10] EPA, *Supplement A to the Guideline on Air Quality Models (Revised)*, 1987.

minimal. Finally, the surface characteristics associated with the Blythe Airport met data reflect conditions consistent with "shrubland (arid region)" and are in no way similar to residential or commercial surface roughness values. Therefore, the surface characteristics associated with the Blythe Airport meteorological station data appropriately reflect surface characteristics at the project site.

Upper air meteorological data are taken from soundings obtained at Tucson, AZ, located approximately 240 miles southeast of the Project. The closest upper air station to the project site is located about 150 miles southwest, at Miramar Naval Air Station, California. Miramar is a coastal site, however, and the marine-influenced surface boundary layer affects Miramar soundings in ways that would not occur in the Lower Colorado River Valley. Therefore, the meteorological data are climatologically dissimilar to the project site.

The next closest upper air station to the project site is located about 224 miles northwest, at Desert Rock, NV. For the period 2006 through 2010; however, the upper air data from Desert Rock are incomplete—approximately 15 percent missing data, which exceeds the 10 percent EPA data completeness threshold.

The third-closest upper air station to Blythe is located at Tucson. Despite its distance, Tucson is the most climatologically similar upper-air station to the project site, mostly due to its latitude. In the late summer, particularly in August, the tropical easterlies migrate so far north that they cross the U.S. Mexican border. Late in the afternoon and into the night, these easterlies sometimes bear big mesoscale convective complexes (MCCs), with all their rain. Because Blythe and Tucson are roughly the same latitude, they see these easterlies; Desert Rock does not because it is farther north. Apart from elevation differences, this difference in summertime wind direction (and precipitation) is the main distinction between the deserts of the lower Colorado River Valley, and the Mojave Desert farther north. So, despite being a farther away from Blythe than Desert Rock, Tucson is more suitable than Desert Rock for upper air data because Tucson and Blythe have more similar latitudes.

Ambient Background Data Selection

Background ambient air quality data for the project area from the monitoring site most representative of the conditions that exist at the proposed project site were used to represent regional background concentrations. Table 5.1-34 shows the monitoring stations that provide the most representative ambient air quality background data.[11]

[11] Selection of the background monitoring stations is also discussed in the modeling protocol, Appendix 5.1H.

Table 5.1-34
Representative Background Ambient Air Quality Monitoring Stations

Pollutant(s)	Monitoring Station	Distance to Project Site
Ozone	Blythe, CA (Riverside County)	6 miles
PM_{10}, $PM_{2.5}$, NO_2, CO	Palm Springs, CA (Riverside County)	107 miles
SO_2	Victorville, CA (San Bernardino County)	163 miles
Lead	San Bernardino, CA (San Bernardino County)	151 miles

Background data representative of conditions at the project site are summarized in Table 5.1-35.

Table 5.1-35
Representative Background Concentrations in the Project Area (μg/m^3)

Pollutant	Averaging Time	2008	2009	2010
Palm Springs, CA (Riverside County)				
NO_2	1 hour (1st high)	92.4	90.5	86.8
	1 hour (98th percentile)[a]	84.9	73.6	75.4
	Annual	17.0	15.1	17.0
CO	1 hour	1,148	2,641	1,837
	8 hours (CA. 1st high)	620	769	643
PM_{10}	24 hours	75	140	37
	Annual Arithmetic Mean	17.7	20.4	18.8
$PM_{2.5}$	24 hours (3-yr avg, 98th Percentile)[b]	18	17	15
	Nat'l 3-yr Avg AAM[c]	7.8	7.4	6.5
Victorville, CA (San Bernardino County)				
SO_2	1 hour	15.8	73.5	136.6
	3 hours	13.1	73.5	112.9
	24 hours	5.3	13.1	18.4
	Annual	2.6	2.6	2.6

Notes:
[a] Per email from Ms. Cohanim at SCAQMD, dated 8/4/2011.
[b] See Table 5 of the modeling protocol in Appendix 5.1H.
Three-year averages are calculated from the annual 98th percentile values.
[c] Annual arithmetic mean.

Construction Impacts

Section 5.1.4.3 describes the development of project emissions estimates over the planned 36-month construction period. An Excel workbook was created to estimate pollutant emissions from construction activities. Emissions from worker commuter trips to and from the project site and heavy trucks delivering materials to and from the site during specific construction activities were also included (see Appendix 5.1F).

Based on information provided by the project engineering design contractor and the emission estimates in Appendix 5.1F, the peak month in terms of combustion air pollutant emissions is expected to be Month 15 and Month 12 for fugitive dust emissions. Worst-case modeling was conducted for short-term averaging times using all combustion emissions from all construction equipment for Month 15 and dust emissions from activities in Month 12 (see Table 5.1-30 and Table 5.1-31). Construction activities were assumed to occur during a 20-hour work day during these periods, reflecting double-shift activity. The maximum 12-month period during the 36-month construction schedule was used to model annual impacts. The emission sources for the construction site were grouped into three categories: exhaust emissions, construction dust emissions, and windblown dust emissions. The vehicle exhaust and construction dust emissions were modeled as 50 volume sources with a vertical dimension of 6 meters. Based on the width of the construction area, the horizontal dimension for each volume source was set to 576.8 meters, with sigma-y = 134.1 meters. The fugitive dust emissions from disturbed areas were represented for modeling purposes as a single area source of approximately 5,060 acres. The effective plume height for this one area source was set at 0.5 meters in the modeling analysis.

As discussed in the modeling protocol, the OLM option of AERMOD was used to account for the role of ambient ozone levels on the atmospheric conversion rate of NO_x emissions (initially mostly in the form of nitric oxide) to NO_2 (the pollutant addressed by ambient standards). Hourly ozone measurements at the Blythe monitoring station during the same five years of the meteorological input data set were used to support the OLM calculations.

Modeling results are shown in Table 5.1-36.

Table 5.1-36 shows that the worst-case background concentration of 24-hour average PM_{10} is already above the state standard and the worst-case background annual PM_{10} concentration is equal to the state annual standard. The project‘s modeled construction PM_{10} impacts are small relative to the background with PM_{10} impacts below the 24-hr and annual PM_{10} federal thresholds for significance of 5 and 1 $\mu g/m^3$, respectively. Because the project‘s modeled construction impacts are below the federal significance thresholds, the project‘s construction emissions would not add a significant contribution to background PM_{10} levels.

Table 5.1-36
Modeled Maximum Impacts During Project Construction

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m³)	Maximum Background Concentration (µg/m³)	Total Concentration[a] (µg/m³)	NAAQS (µg/m³)	CAAQS (µg/m³)
NO_2	1-hr (highest)	30.5	92.4	123	--	339
	1-hr (98th percentile)[b]		78.0	109	188	--
	Annual	0.9	17.0	18	100	57
SO_2	1-hr	0.08	136.6	137	196	655
	3-hr	0.05	112.9	113	1300	--
	24-hr	0.02	18.4	18	--	105
	Annual	0.00	2.6	3	80	--
CO	1-hr	18.6	1,837	1,856	40,000	23,000
	8-hr	8.8	643	652	10,000	20.000
PM_{10}	24-hr	4.5	140	145	150	50
	Annual	0.5	20.4	21	--	20
$PM_{2.5}$	24-hr[b]	0.9	18	19	35	--
	Annual[c]	0.1	7.8	8	15.0	12

Notes:
[a] Total concentrations shown in this table are the sum of the maximum predicted impact and the maximum measured background concentration. Because the maximum impact will not occur at the same time as the maximum background concentration, the actual maximum combined impact will be lower.
[b] Background concentration shown is the three-year average of the 98th percentile values (2008 to 2010), in accordance with the form of the federal standard Total concentrations shown for 1-hour NO2 is maximum modeled project impact combined with maximum background concentration (Tier 1 analysis in Section 3.6 of the modeling protocol).
[c] Background concentration shown is the three-year average of the annual arithmetic mean, in accordance with the form of the standard.

Emissions and modeled impacts from construction activities are not unusual compared with those from other construction projects. Appendix 5.1F describes the mitigation measures that will be used during construction to minimize these impacts.

The data summarized in Table 5.1-36 show that construction emissions will not cause new exceedances of any other state or federal air quality standards, including the state and federal 1-hour NO_2 standards.

Operational Impacts

Normal Plant Operations

The results of the AERMOD assessment for normal plant operations are summarized in Table 51.37. Listed below are the operating assumptions used in developing the emission rates for each emissions unit

and averaging period. Emission rates and stack parameters used in modeling impacts during normal plan operations are shown in Table 5.1D-2, Appendix 5.1D.

1-hour averages

- All emergency engines operational for testing with operation of startup/nighttime preservation boilers at full load; OR
- All boilers operating at full load.

3-hour and 8-hour averages

- All emergency engines operational for testing with operation of startup/nighttime preservation boilers at full load; OR
- All boilers operating at full load.

24-hour averages

- All boilers operating with maximum daily emissions and WSACs in operation; OR
- Startup and nighttime preservation boilers operating at full load and all emergency engines operational for testing.

Annual Averages

- All equipment included.
- For all pollutants, maximum annual emissions used to calculate average hourly emission rate.

Startup Impact Analysis

As discussed in Section 5.1.4.2, the boilers will need to undergo occasional cold startups, during which they may operate for extended periods at low loads with, in some cases, emission rates that are slightly higher than emissions during normal operations. The ambient air quality impact analysis included assessments of potential air quality impacts of boiler startups. To simplify the analyses and make sure they are conservative, the following scenarios were evaluated:

- Auxiliary boiler startup: One unit at each power block is in startup simultaneously. No other boilers or engines are operating. Although startup times for the auxiliary boilers will not exceed 6 hours and cold startups will be phased over a two-day period, 8-hour CO emission rates reflect 8 hours of startup to be conservative.
- Startup boiler startup: Startup boiler at each power block is in startup simultaneously; nighttime boilers are in operation as well. Although startup times for the startup boilers will not exceed 5 hours, 8-hour CO emission rates reflect 8 hours of startup to be conservative.
- Nighttime boiler startup: Nighttime boiler at each power block is in startup simultaneously. Startups may occur while auxiliary boilers are in operation. Although startup times for the

nighttime preservation boilers will not exceed 4 hours, 8-hour CO emission rates reflect 8 hours of startup to be conservative.

Emission rates and stack parameters for the boiler startup analyses are shown in Table 5.1D-3, Appendix 5.1D. Results of the startup impact analysis are shown in Table 5.1-37 along with results for other operating conditions. The highest startup impacts occur during startup of the auxiliary boilers.

Table 5.1-37
Summary of Modeling Results for Facility Operations

Pollutant	Averaging Period	Modeled Concentration (µg/m³)				PSD Significant Impact Level (µg/m³)
		Normal Operation	Startup Operation	Hot Standby Operation	Inversion Breakup Fumigation	
NO_2	1-hr (max)	194a	35	31	27	7.5e
	1-hr (98th pct)	149a	27	19	n/ac	--
	Annual	0.08	n/ab	n/ab	n/ad	1.0
SO_2	1-hr	10	0.9	0.6	5	7.8e
	3-hr	4	0.4	0.2	4	25
	24-hr	0.2	n/ab	n/ab	2	5
	Annual	0.01	n/ab	n/ab	n/ad	1.0
CO	1-hr	237	95	52	68	2000
	8-hr	19	24	11	45	500
PM_{10}	24-hr	0.4	n/ab	n/ab	0.8	5
	Annual	0.02	n/ab	n/ab	n/ad	1
$PM_{2.5}$	24-hr	0.4	n/ab	n/ab	0.8	1.2
	Annual	0.02	n/ab	n/ab	n/ad	0.3

Notes:

[a] Highest 1-hour average NO_2 impacts occur during emergency engine testing; maximum impacts for other pollutants and averaging periods occur during boiler operation. Maximum 1-hour NO_2 impact during normal boiler operations is 47 µg/m³; 98th percentile NO_2 impact during normal boiler operation is 32 µg/m³. All NO_2 results except fumigation reflect ozone limiting.

[b] Startup and hot standby operations are short-term operating modes and do not affect averaging periods longer than 8 hours.

[c] Inversion breakup fumigation is modeled using screening models so no 98th percentile value can be produced.

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

[e] These are interim SILs and have not been formally adopted by EPA.

Ambient Impacts During Hot Standby Operation

On some days when cloudy weather is anticipated, the auxiliary boilers may be operated on hot standby starting earlier in the day so that they will be available to augment the solar operations when solar energy diminishes or during transient cloudy conditions. When operating in hot standby mode, the boilers would operate at about 5 percent of their rated heat input rate. As discussed earlier, emissions during hot standby will be very low because of the low heat input. However, because of the low potential stack

velocities, this operating mode has been included in the ambient air quality assessment. The modeling analysis for this operating mode assumes that all six boilers are on hot standby simultaneously for up to 8 hours. This assumption conservatively overestimates impacts during this operating mode. Emission rates and stack parameters used in evaluating impacts during hot standby operation are shown in Table 5.1D-4, Appendix 5.1D. Modeled impacts are shown in Table 5.1-37.

Inversion Breakup Fumigation Modeling

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

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from EPA[12] was followed in evaluating fumigation impacts. The maximum fumigation impact from this analysis, which is shown in more detail in Table 5.1D-5, Appendix 5.1D, showed that impacts under fumigation conditions are expected to be higher than the maximum concentrations calculated by AERMOD under normal operations for 8-hr average CO, 24-hr average SO2, and 24-hr average $PM_{10}/PM_{2.5}$ impacts. Inversion breakup impacts are also shown in Table 5.1-37.

The modeling results in Table 5.1-37 show that only 1-hour NO_2 and SO_2 impacts exceed the interim PSD SILs—all other modeled impacts during all operating scenarios are below the significant impact levels.

Demonstration of Compliance

The maximum facility impacts calculated from the modeling analyses described above are summarized in Table 5.1-37 above. The highest modeled 1-hr average NO_2 and CO impacts are expected to occur during engine testing; the highest impacts for other pollutants and averaging periods occur under normal boiler operations. To determine the project‘s air quality impacts, the modeled concentrations are added to the highest reported background ambient air concentrations and then compared to the applicable ambient air quality standards. The highest reported background ambient concentrations were discussed in Section 5.1.3.4 and the monitored concentrations during the past three years are shown in Table 5.1-35. More detailed discussions of why the data collected at these stations are representative of ambient concentrations in the vicinity of the project are provided in Appendix 5.1H.

Maximum project modeling results and background ambient levels are shown in Table 5.1-38. Table 5.1-38 shows that the worst-case background concentration of 24-hour average PM_{10} is already above the state standard and the worst-case background annual PM_{10} concentration is equal to the state annual standard. The project‘s modeled PM_{10} impacts are below the 24-hr and annual PM_{10} federal thresholds

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

for significance of 5 and 1 µg/m3, respectively. Because the project's modeled impacts are below the federal significance thresholds, the project's emissions would not add a significant contribution to background PM_{10} levels. The data summarized in Table 5.1-38 show that project emissions will not cause new exceedances of any other state or federal air quality standards, including the state and federal 1-hour NO_2 standards.

Table 5.1-38
Summary of Results (Modeled Maximum Impacts plus Background)

Pollutant	Averaging Time	Project Impact (µg/m³)	Background Concentration (µg/m³)	Total Concentration (Project Impact plus Background) (µg/m³)	NAAQS (µg/m³)	CAAQS (µg/m³)
NO_2	1-hr (max)	194	92.4	286	--	339
	1-hr (98th percentile)	149	78.0	167[a]	188	--
	Annual	0.08	17.0	17	100	57
SO_2	1-hr	10	136.6	147	196	655
	3-hr	4	112.9	117	1300	--
	24-hr	2	18.4	20	--	105
	Annual	0.01	2.6	3	80	--
CO	1-hr	237	1,837	2,074	40,000	23,000
	8-hr	45	643	688	10,000	20
PM_{10}	24-hr	0.8	140	141	150	50
	Annual	0.02	20.4	20	--	20
$PM_{2.5}$	24-hrb	0.8	18	19	35	--
	Annualc	0.02	7.8	8	15	12

Note:
[a] Total concentrations shown for 1-hour NO_2 are modeled project impacts combined with concurrent hourly NO_2 monitoring data (Tier 4 analysis in Section 3.6 of the modeling protocol). This value represents the five-year average of the annual 1-hr NO_2 98th percentile (modeled impact plus background) for each year (2006 to 2010) as required by June 28, 2010 EPA 1-hr NO_2 NAAQS guidance document. All other totals shown are maximum modeled project impacts combined with maximum monitored background data from Table .Table .

[b] Background concentration shown is the three-year average of the 98th percentile values (2008 to 2010), in accordance with the form of the federal standard.

[c] Background concentration shown is the three-year average of the annual arithmetic mean, in accordance with the form of the standard.

PSD Increment Consumption

The PSD program was established to allow emission increases (increments of consumption) that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded the NAAQS. As discussed in Section 5.1.6.1, the project is not subject to PSD review.

Preconstruction Monitoring

Because the Project is not subject to PSD review, EPA will not require preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area.

Commissioning Impacts

Commissioning emissions are quantified in Table 5.1B-17, Appendix 5.1B. Maximum emissions from each boiler are expected to occur during the cold start/tuning phase of commissioning, and during that period boiler operation and emissions are expected to be similar to those that occur during cold startups. Ambient impacts during boiler startups were evaluated above (see Table 5.1-37) and shown not to be expected to cause or contribute to any violations of the ambient air quality standards.

5.1.4.6 Screening Health Risk Assessment

The screening health risk assessment (SHRA) was conducted to determine expected impacts on public health of the noncriteria pollutant emissions from the operation of the boilers and emergency Diesel engines.[13] The SHRA was conducted in accordance with the OEHHA's ―AirToxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments" (October 2003).

The SHRA estimated the offsite potential Maximum Incremental Cancer Risk (MICR) at the point of maximum impact, at the location (e.g., residence) of the maximally exposed individual (MEI), and to the maximally exposed worker (MEW); and the potential long-term (chronic) and short-term (acute) non-carcinogenic health impacts from non-carcinogenic emissions. The CARB/OEHHA-approved Hotspots Analysis and Reporting Program (HARP) (Version 1.4d) was used to evaluate multipathway exposure to non-criteria pollutant emissions. The individual pollutant carcinogenic risks are assumed to be additive. Because of the conservatism (over prediction) built into the established risk analysis methodology, the actual risks will be lower than those estimated.

The SHRA utilized the following information:

- Inhalation cancer potency factors for the carcinogenic emissions.
- Noncancer Reference Exposure levels (RELs) for determining chronic and acute non-carcinogenic health impacts.
- One-hour and annual average emission rates for each non-criteria pollutant.
- The modeled maximum offsite concentration of each non-criteria pollutant emitted.

Many of the carcinogenic compounds also have non-carcinogenic health effects and are therefore included in the determination of both potential carcinogenic and noncarcinogenic effects. RELs are used

[13] The WSACs were not included in the screening HRA because their TAC emissions are negligible (see Table 5.1B-16, Appendix 5.1B).

as indicators of potential non-carcinogenic adverse health effects. RELs are generally based on the most sensitive adverse health effect reported and are designed to protect the most sensitive individuals. However, exceeding the REL does not automatically indicate a health impact. The OEHHA RELs were used to determine potential adverse health effects from noncarcinogenic compounds. A potential chronic health hazard index for each relevant non-carcinogenic pollutant is then determined by the ratio of the pollutant maximum annual average concentration to its respective REL. Similarly, a potential acute health hazard index for each relevant non-carcinogenic pollutant is determined by the ratio of the pollutant maximum one-hour average concentration to its respective REL. The individual indices are summed to determine the overall hazard index for the project. Because noncarcinogenic compounds target different internal systems or organs (e.g., respiratory system, nervous system, eyes), this sum is considered conservative.

The SHRA results are compared with the established risk management procedures for the determination of acceptability. The established risk management criteria include those listed below.

- If the MICR at a residential receptor is less than one in one million, the facility risk is considered not significant.
- If the MICR at a residential receptor is greater than one in one million but less than ten in one million and Toxics-Best Available Control Technology (T-BACT) has been applied to reduce risks, the facility risk is considered acceptable.
- If the MICR at PMI is greater than ten in one million but less than 100 in one million and there are mitigating circumstances that, in the judgment of a regulatory agency, outweigh the risk, the risk is considered acceptable.
- For non-carcinogenic effects, total hazard indices of one or less are considered not significant.
- For a hazard index greater than one, OEHHA, the CEC, and the MDAQMD may conduct a more refined review of the analysis and determine whether the impact is acceptable.

The SHRA includes the noncriteria pollutants listed above in Table 5.1-29. The receptor grid described earlier for criteria pollutant modeling was used for the SHRA. The potential health risks are presented in Table 5.1-39, and the detailed calculations are provided in Appendix 5.1E. The locations of the maximum modeled risks are shown in Appendix 5.1E, Figure 5.1E-1.

Table 5.1-39
Potential Health Risks from the Operation of the Project

	Project	Significance Thresholds	Significant?
Maximum Incremental Cancer Risk (MICR) at Point of Maximum Impact	1.38 in one million	10 in one million	No
MICR at Residential Receptor	0.10 in one million	1 in one million	No
Acute Inhalation Health Hazard Index: 1-hour	0.003	1.0	No

Table 5.1-39
Potential Health Risks from the Operation of the Project

	Project	Significance Thresholds	Significant?
Acute Inhalation Health Hazard Index: 8-hour	0.002	1.0	No
Chronic Inhalation Health Hazard Index	0.0007	1.0	No

The acute and chronic health hazard indices are well below 1.0, and hence, are not significant. The MICR at a residential receptor is 0.1 in one million, below the MDAQMD's 1 in one million threshold for additional analysis, and the MICR at PMI is less than the ten in one million significance threshold for the project. The project will not pose a significant health risk at any location, under any weather conditions, under any operating conditions.

Potential health risks during construction are evaluated in Appendix 5.1F. This evaluation concludes that health risks during construction will not be significant.

5.1.5 Cumulative Effects

A CEQA cumulative impacts analysis examines potential cumulative air quality impacts that may result from the project and other reasonably foreseeable projects. Such an analysis is generally required only when project impacts are significant.

5.1.5.1 Cumulative Construction Impacts

Project construction will occur over a 36-month period, as discussed in Appendix 5.1F. In addition, as discussed in Appendix 5.1F, impacts during construction will be localized. Construction of the transmission line will occur concurrently with on-site construction, but most of the linears construction will occur at average distances of approximately 5 miles from the project site. Because impacts from linears construction are also expected to be localized, it is unlikely that any cumulative construction impacts will occur with the exception of the construction of the linears that are closest to the project. Therefore any cumulative construction impacts will be temporary and localized and as such are not expected to be significant.

5.1.5.2 Cumulative Operational Impacts

To ensure that potential cumulative impacts of the project and other nearby projects are adequately considered, a cumulative impacts analysis will be conducted in accordance with the protocol included as Appendix 5.1G.

5.1.5.3 Greenhouse Gas Cumulative Effects Analysis

In 2006, the California Legislature adopted AB 32, the California Global Warming Solutions Act of 2006. This legislation started California on the path to reduce emissions of greenhouse gases (GHGs) in California to 1990 levels. The principal regulated GHG is carbon dioxide, which is emitted primarily from the combustion of fossil fuels.

The legislation requires CARB to determine the 1990 levels, and to adopt regulatory mechanisms to bring California‘s emissions back down to those levels by 2020. The legislation does not require that individual facilities or sectors return to 1990 levels. It is expected that some sectors will achieve greater reductions than others.

It is unlikely that California‘s entire program will have a measurable impact on global climate change. Rather, it is asserted that California‘s effort, in conjunction with similar efforts worldwide, could reduce or even eliminate the negative impacts associated with anthropogenically induced global climate change.

It follows that no individual project, or even the cumulative effects of all of the reasonably foreseeable projects in California, will have a measurable impact on global climate change. However, new emissions of carbon dioxide will make it more difficult for the state to meet its goal of reducing GHG emissions to 1990 levels.

State agencies are developing the plans and regulations necessary to achieve the GHG emission reductions required by AB 32. The starting point of these plans is a projection of what emissions would be in 2020 if business went on as usual. A significant amount of new emissions in the ―business as usual” scenario comes from increased demand for electricity in California. In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

Regulations already in place require that much of that increased demand for electricity in California be met by projects like Rio Mesa SEGF, which generate energy that does not derive from the combustion of fossil fuels. Senate Bill x12 (SB 2), which requires 33 percent of retail electricity sales to come from renewable resources by 2020. SB 2 also establishes interim targets for renewable generation to ensure that timely progress is made toward the 33 percent RPS goal, requiring that 75 percent of generation must come from within California by 2016. The Rio Mesa SEGF project will help to further progress toward the SB 2 goals by providing a reliable, in-state source of renewable electricity that will come online before the 2016 interim deadline.

Most renewable energy facilities such as wind and solar are ―intermittent resources,” meaning these resources are not available to generate in all hours and thus have limited operating capacity. For example, intermittent resources can be limited by meteorological conditions on an hourly, daily, and seasonal basis. In addition, the availability of intermittent resources is often unrelated to the load profile they serve. For example, some solar resources reach peak production around 12:00 noon, while the electrical demand sometimes peaks between 5:00 p.m. and 7:00 p.m. Rio Mesa SEGF has the advantage over many other solar facilities of being able to provide electricity during the peak evening demand period through the use

of the auxiliary boilers to augment the solar operation when solar energy diminishes or during transient cloudy conditions that impact the available solar energy.

The proposed project supports the state's strategy to reduce fuel use and GHG emissions. Although the use of natural gas-fired auxiliary boilers will result in GHG emissions, the overall GHG emission rate for the project will be below the RPS standard of 0.500 metric tons CO_2 per MWh and below the rates for comparably sized fossil-fueled projects. Table 5.1-40 compares the GHG emissions performance of Rio Mesa SEGF with that of other types of power plants.

Table 5.1-40
Comparison of GHG Emissions Performance

Type of Power Plant	GHG Emissions Performance, MT CO_2/MW[a]
Rio Mesa SEGF	0.043
Natural Gas Combined Cycle	0.370 to 0.430
EPS	0.500
Natural Gas-Fired Boiler	0.550 to 0.650
Natural Gas-Fired Peaking Turbine	0.550 to 0.900
Coal-Fired Boiler	~1.00

Note:
[a] All GHG emissions performance data except Rio Mesa SEGF from Ivanpah FSA, Appendix Air-1, October 2009.

Further, even though it is possible to quantify how many gross GHG emissions are attributable to a project, it is difficult to determine whether this will result in a net increase of these emissions—and, if so, by how much—due to the displacement by the Project of emissions from fossil generating resources. However, the loading order adopted in 2003 by the CEC and PUC prioritizes the use of generation from renewables, such as Rio Mesa SEGF, over generation from fossil fuel resources. According to the CEC, "[]s California moves towards an increase reliance on renewable energy, non-renewable energy sources will be curtailed or displaced."[14] Therefore, it would be speculative to conclude that greenhouse gas emissions from any given project will cause a cumulatively significant adverse impact.

Demand for electricity in California will not be affected by Rio Mesa SEGF. Every megawatt-hour generated by the Project, however, will displace a megawatt-hour that would otherwise have been generated by a more traditional (i.e., fossil-fuel-fired) source of electricity. The Project will increase renewable generation and contribute to the state's efforts to move toward a high-renewable, low-GHG electricity system. The Project is therefore expected to result in a net reduction in GHG emissions.

[14] Commission Decision for the Ivanpah SEGS, CEC-800-2010-004 CMF, September 2010.

As directed by SB 97, the Resources Agency adopted Amendments to the CEQA Guidelines for greenhouse gas emissions (GHG CEQA Guidance) on December 30, 2009. On March 18, 2010, those amendments became effective.

The GHG CEQA Guidance included the following elements:

- Quantification of GHG emissions;
- Determination of whether the project may increase or decrease GHG emissions as compared to existing environmental setting;
- Determination of whether the project emissions exceed a threshold of significance determined by the lead agency;
- The extent to which the project complies with state, regional, or local plans for reduction or mitigation of GHGs; and
- Mitigation measures.

GHG emissions were quantified in Table 5.1-27. The discussion above supports a determination that the project can be expected to decrease GHG emissions as compared with the current situation. Rio Mesa SEGF will provide more than 2,205 GWh per year of renewable generation that could replace aging, less-efficient, coal-fired and/or once-through cooled generating resources. The preceding discussion also demonstrates that GHG emissions from the Project will be below the EPS, which is generally accepted as a threshold of significance for GHG emissions from electric generation facilities, and will further the state‘s progress toward its RPS and SB 2 goals. Because the GHG emissions are not expected to be significant, no additional mitigation is necessary.

5.1.6 Consistency with Laws, Ordinances, Regulations, and Standards

This section considers consistency separately for federal, state, and local requirements.

5.1.6.1 Consistency with Federal Requirements

Prevention of Significant Deterioration Program

The PSD requirements apply, on a pollutant-specific basis, to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 TPY, or any other facility that emits at least 250 TPY. Effective July 1, 2011, PSD will also apply to a new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) and more than 100 TPY of any individual GHG. Because the emissions of all PSD pollutants will be below 100 TPY, and the GHG emissions for the proposed project will be below the PSD major source threshold of 100,000 TPY, the proposed project is not subject to PSD review.

Nonattainment New Source Review

Nonattainment New Source Review jurisdiction has been delegated to the MDAQMD for all pollutants and is discussed further under local requirement conformance below.

New Source Performance Standards

The boilers used at the proposed project will be subject to the following NSPS:

- Subpart Da: New Source Performance Standards for Electric Utility Steam Generating Units (auxiliary boilers).
- Subpart Db: New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units (startup boilers).
- Subpart Dc: New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units (nighttime preservation boilers).

The NSPS emissions limits are compared with the proposed permit limits in Table 5.1-41 below. Emissions from the boilers will be well below the NSPS limits.

Table 5.1-41
Comparison of Boiler Emission Rates with Applicable NSPS Standards

	NO_x	SO_2	PM
Subpart Da Limit (Auxiliary Boilers)	0.11 lb/MMBtu	1.4 lb/MWh	0.015 lb/MMBtu
Subpart Db Limit (Startup Boilers)	0.20 lb/MMBtu	0.20 lb/MMBtu	none
Subpart Dc Limit (Nighttime Preservation Boilers)	None	none	none
Proposed Permit Level	0.011 lb/MMBtu	0.0021 lb/MMBtu	0.005 lb/MMBtu

The boilers are exempt from the continuous opacity and SOx monitoring requirements of the NSPS because they will burn solely natural gas fuel. The auxiliary boilers must continuously monitor NO_x emissions (40 CFR 60.49a), but will use the NO_x CEMS required under Part 75 to meet the NO_x monitoring requirement. The startup boilers will use predictive emissions monitoring in lieu of continuous monitoring for NO_x (40 CFR 48b(g)(2)).

- Subpart IIII: New Source Performance Standards for Stationary Compression Ignition Engines (emergency engines, including fire pump engines)

The power block emergency generators, rated at 2.5 MW, are subject to Nonroad Tier 2 emission standards;[15] the Project will comply by purchasing Tier 2 engines. The common area emergency generator, rated at 500 kW, is subject to Nonroad Tier 3 standards; a Tier 3 –certified engine has been selected for this application. The fire pump engines proposed for the project are certified to Tier 3 nonroad standards, as required by the NSPS.

National Emission Standards for Hazardous Air Pollutants

This program establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific source categories. These standards are implemented at the local level with federal oversight. EPA has promulgated NESHAP for boilers at area sources (40 CFR 63 Subpart JJJJJJ) and compression ignition engines (RICE; 40 CFR 63 Subpart ZZZZ). However, the area source boiler NESHAP does not apply to natural gas-fired units, while the RICE NESHAP requires only new emergency RICE to comply with the applicable NSPS. Therefore the NESHAP will impose no additional requirements on the facility.

Acid Rain Program

This program requires the monitoring and reporting of emissions of acidic compounds and their precursors from combustion power generation equipment. These requirements are implemented at the local level with federal oversight. MDAQMD has received delegation authority to implement Title IV. The project will comply with the acid rain program requirements and will file an acid rain permit application in accordance with the deadlines in MDAQMD Rule 1210.

Title V Operating Permits Program

This program requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. MDAQMD has received delegation authority for this program. The project will comply with the requirements of Title V by filing a Title V permit application in accordance with the deadlines in MDAQMD Regulation XII.

5.1.6.2 Consistency with State Requirements

As discussed in Section 5.1.2.2, state law established local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. The proposed project is under the local jurisdiction of the MDAQMD; therefore, compliance with MDAQMD regulations will assure compliance with state air quality requirements.

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[15] Because these are emergency engines, they are not required to meet standards that require –add-on" controls, such as diesel particulate filters or SCR.

The CO_2 emission rate of 0.041 MT/MWh would meet the EPS of 0.51 MT/MWh. However, as a solar power plant, the project is not designed or intended for base load generation. The EPS applies only to procurements that entail an annualized capacity factor in excess of 60 percent. With an expected operating capacity that is the equivalent of approximately 3,000 full-load hours per year, the project's annualized capacity factor will be less than 50 percent. Therefore, the SB 1368 limitation does not apply to this facility.

5.1.6.3 Consistency with Local Requirements

The MDAQMD has been delegated responsibility for implementing local, state, and federal air quality regulations in the Mojave Desert Air Basin. The proposed project is subject to District regulations that apply to new stationary sources, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from non-criteria pollutants. The following sections include the evaluation of facility compliance with applicable District requirements.

New Source Review Requirements

The MDAQMD's NSR rule (Regulation XIII-New Source Review) establishes the criteria for siting new and modified emission sources; this rule is applicable to the proposed project. There are three basic requirements within the NSR rules. First, BACT requirements must be applied at any new facility with potential emissions above specified threshold quantities. Second, all potential emission increases of nonattainment pollutants or precursors from the proposed source above specified thresholds must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of ERCs. Third, an ambient air quality impact analysis must be conducted to confirm that the project does not cause or contribute to a violation of a national or California AAQS or jeopardize public health.

BACT

A comparison of potential emissions with the BACT thresholds in MDAQMD Rule 1303.A is presented in Tbale 5.1-42. The detailed per unit daily emission calculations are included in Appendix 5.1.B, Table 5.1B-11. Under Rule 219.E.4.c, the WSACs are exempt from permitting requirements due to a water recirculation rate per WSAC of less than 10,000 gallons per minute.[16] Therefore, the WSACs are not included in this table. This table shows that the boilers and emergency engines are not required to use BACT for NOx, VOC, SO_2 or PM_{10}.

Nevertheless, a detailed discussion regarding control technology options for the boilers is provided in Appendix 5.1C. A summary of the proposed controlled emission rates is provided in Table 5.1-43

[16] The WSACs are exempt from permit requirements (MDAQMD Rule 219.E.4.c: water cooling towers with a water recirculation rate of less than 10,000 gpm and not used for evaporative cooling of process water).

Table 5.1-42
Applicability of BACT Requirements Under NSR

Pollutant	BACT Threshold, lb/day	Maximum Boiler Emissions - Per Unit, lb/day	Maximum Engine Emissions – Per Unit, lb/day	BACT Required?
NOx	25	22	19	no
VOC	25	11	1	no
SO_2	25	4	0	no
PM_{10}	25	10	1	no

Table 5.1-43
Summary of Proposed BACT

Pollutant	Control Technology	Concentration
NOx, boilers	ultra-low NO_x burners, flue gas recirculation	9 ppmc
CO	good combustion practices	25 to 50 ppmc
VOC	good combustion practices	12.6 ppmc
SO_2	natural gas fuel	--
$PM_{10}/PM_{2.5}$, boilers	natural gas fuel	--
$PM_{10}/PM_{2.5}$, WSACs	high-efficiency drift eliminators	0.0005% (drift rate)
GHGs	natural gas fuel supplementing solar generation	0.043 Mt/MWh

Offsets

MDAQMD Rule 1303.B requires that projects with operational emissions above 100 tons/year of CO, 25 tons/year of NOx, VOC, or SOx, or 15 tons/year of PM_{10} provide emission offsets by emission reductions from other sources. As shown in Table 5.1-28 above, the facility-wide annual emissions from the project will not exceed the District‘s offset thresholds.

Air Quality Impact Analysis

Under MDAQMD new source review regulations (Rule 1302.C.2.b), if a new or modified project triggers the offset requirements under Rule 1303.B, an air quality impact analysis must be performed to confirm that the emission increases for a project will not interfere with the attainment or maintenance of an applicable ambient air quality standard or cause additional violations of a standard anywhere the standard is already exceeded. As discussed above, the proposed project will not trigger offset requirements; therefore, an air quality modeling analysis is not required under the MDAQMD new source review regulations. Nonetheless, the modeling results presented in Section 5.1.4.5 show that the proposed

project will not interfere with the attainment or maintenance of the applicable air quality standards or cause additional violations of any standards.

New Source Review Requirements for Air Toxics

Regulation XIII, Rule 1320 (NSR for TACs) provides a mechanism for evaluating the potential impact of toxic air contaminant air emissions from new, modified, and relocated facilities or permit units in the MDAQMD. The rule requires a demonstration that the source will not exceed the applicable health risk thresholds. The project will comply with the requirements of this rule. An air toxics health risk assessment consistent with MDAQMD requirements is provided in Section 5.16, Public Health.

New Source Performance Standards

The MDAQMD's New Source Performance Standards (Regulation IX) incorporates the federal NSPS from 40 CFR Part 60. The applicability and requirements of and compliance with the New Source Performance Standards are discussed above under the federal regulations section.

Federal Programs and Permits

The federal Title IV acid rain program requirement and Title V operational permit requirements are in MDAQMD's Regulation XII. The applicability and requirements of and compliance with these programs and permits are discussed above under the federal regulations section.

Public Notification

Public notice under Rule 1306.E.2 (Electric Energy Generating Facilities) is required and the applicant expects the MDAQMD Air Pollution Control Officer will provide this notice in a timely manner.

Permit Fees

The MDAQMD requirements regarding permit fees are specified in Regulation III. This regulation establishes the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources. The project will pay the applicable fees in accordance with these requirements.

Prohibitions

The MDAQMD prohibitions for specific types of sources and pollutants are addressed in Regulation IV. The prohibition rules that apply to the project are summarized below.

Rule 401 – Visible Emissions: This rule prohibits any source from discharging any emissions of any air contaminant that is darker in shade than that designated as Number 1 on the Ringelmann Chart for a period or periods aggregating more than 3 minutes in any period of 60 consecutive minutes. The project's use of natural gas would eliminate the possibility of dark visible emissions. Therefore, the project is expected to comply with this requirement.

Rule 402 – Nuisance: This rule prohibits the discharge from a facility of air contaminants that cause injury, detriment, nuisance, or annoyance to the public, or cause damage to business or property. The project would not emit odorous pollutants, and the screening level health risk assessment included in the Section 5.16, Public Health demonstrates that the potential health risk from the emissions is less than significant.

Rule 403 – Fugitive Dust: This rule prohibits visible dust emissions off property due to transport, handling, construction, or storage activity. Requires dust minimization during grading and clearing of land. Limits the difference between upwind and downwind PM concentrations to 100 µg/cubic meter (5 hour average). Requires removal of particulate matter from equipment prior to movement on paved streets. Construction emission mitigation measures will ensure compliance with this requirement.

Rule 404 – Particulate Matter: This rule prohibits PM emissions in excess of grains per dry standard cubic foot (gr/dscf) limits based on exhaust flow rates. The combustion of fuels in steam generators is exempt from this rule. Therefore, this rule only applies to the emergency engines at the proposed project. The proposed PM_{10} emission rates for the engines are below the rule limits. For example, the power block emergency engine PM_{10} emissions are approximately 0.0065 gr/dscf compared to the rule limit of approximately 0.06 gr/dscf.

Rule 406 – Specific Contaminants: This rule prohibits sulfur emissions, calculated as SO_2, in excess of 0.05 percent by volume (500 ppmv), and acid gas emissions above specified levels. SO_2 emissions from the project will be below 0.5 ppmv, based on the maximum expected fuel sulfur content of 0.75 gr/100 scf.

Rule 407 – Liquid and Gaseous Air Contaminants: This rule prohibits carbon monoxide emissions in excess of 2000 parts per million by volume, ppmv. CO emissions from the project boilers and engines will be well below 2000 ppmv.

Rule 409 – Combustion Contaminants: This rule prohibits PM emissions in excess of 0.1 grains per dry standard cubic foot (gr/dscf) from combustion equipment. This rule applies to the boilers and emergency engines at the proposed project. The proposed PM_{10} emission rates for the boilers and engines are below the rule limit. For example, the power block emergency engine PM_{10} emissions are approximately 0.0065 gr/dscf and the auxiliary boiler PM_{10} emissions are approximately 0.0019 gr/dscf.

Rule 431 – Sulfur Content of Fuels: This rule prohibits any stationary source from using any gaseous fuel containing a total sulfur content of more than 800 ppm (47 grains per 100 cubic feet) and liquid fuel with a sulfur content of more than 0.5 percent sulfur by weight. The natural gas used for the Project will have a maximum sulfur content of 0.75 (short term) grains per 100 cubic feet of dry gaseous fuel and the CARB Diesel used by the emergency engines will have a maximum sulfur content of 0.0015 percent by weight, well below the limits under this rule.

Rule 475 – Electric Power Generating Equipment: This rule limits NO_x and PM emissions from electrical generating equipment rated greater than or equal to 50 MMBtu/hr to RACT levels. The NO_x and PM limits apply to the auxiliary and startup boilers (NO_x limit = 80 ppmv @ 3 percent O2; PM limit not to exceed 0.01 gr/dscf @ 3 percent O2 and 11 lbs/hour). The proposed auxiliary and startup boilers will meet this requirement.

Rule 476 – Steam Generating Equipment: This rule limits NO_x emissions from steam generators rated above 50 MMBtu/hr to 125 ppm. This rule applies to the boilers at the proposed project. The boilers will be designed to meet a NO_x level of 9 ppm.

5.1.7 Mitigation Measures

5.1.7.1 Operational Emissions: Permitted Units

The project's emissions are below the levels that require BACT or offsets under MDAQMD regulations. Although BACT is not required, emissions from the boilers and engines will be well controlled, as discussed in Appendix 5.1C. Modeling shows that the project will not result in any significant air quality impacts.

Table 5.1-44 compares the emissions from the project with the emissions that would occur if the energy provided by the project were provided by a new 750 MW natural gas-fired combined cycle turbine project operating 3,000 hours per year, utilizing Best Available Control Technology (assumptions: heat rate of 7,000 Btu/kWh HHV, 2 ppmv NOx, 3 lb PM_{10} per 100 MW, 2 ppmv CO, 1.4 ppmv VOC, 0.0006 lb/MMBtu SO_2, 200 starts per year per gas turbine at approximately 56 lbs/start for NO_x per 250 MW gas turbine and 417 lbs/start for CO per 250 MW gas turbine).

Table 5.1-44
Comparison of Emissions Between Rio Mesa Solar Electric Generating Facility and a Well-Controlled Gas Turbine

Emissions/Equipment	Pollutant					
	NO_x	SO_2	CO	VOC	$PM_{10}/PM_{2.5}$	GHG
Maximum Annual Emissions, total tons per year						
Rio Mesa SEFG	13.8	1.8	30.6	5.1	4.5	99,122
Combined-Cycle Gas Turbine Project	82.9	4.7	118.1	12.6	33.8	916,837

5.1.7.2 Construction Activities

Mitigation measures for construction period impacts are discussed in Appendix 5.1F.

5.1.7.3 Greenhouse Gas Emissions

Every megawatt-hour generated by the project will displace a megawatt-hour that would otherwise have been generated by a more traditional (i.e., fossil-fuel-fired) source of electricity. The project therefore is expected to result in a net reduction in emissions of GHGs.

As discussed above, the project's GHG impacts are not significant. GHG regulatory offset requirements will be addressed through CARB-approved measures, including the possible acquisition of allowances under a cap-and-trade program.

5.1.7.4 Mirror Cleaning and Other Maintenance Activities

Emissions from mirror cleaning activities were quantified in Section 5.1.4.3. To minimize exhaust emissions from the mirror washing and refueling vehicles, the project will use new model year vehicles that meet then-current California on-road vehicle emission standards or applicable EPA /California off-road engine emission standards for the model year in effect when the vehicles are purchased. To minimize fugitive dust emissions from maintenance operations, including travel of mirror washing vehicles on unpaved roads, a dust control plan will be prepared that includes fugitive dust control measures such as use of soil stabilization techniques and limits on vehicle speed. Mitigation measures that will be included in the operational dust control plan include the following:

- Operations and wind erosion control techniques, such as windbreaks and chemical dust suppressants, and ongoing maintenance procedures that will be used on areas that could be disturbed by vehicles or wind anywhere within the project boundaries; and
- Limitations on vehicles speeds to not more than 10 mph on unpaved roadways that are not stabilized and up to 25 mph on stabilized unpaved roads as long as such speeds to not create visible dust emissions.

5.1.8 Involved Agencies and Agency Contacts

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

CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update as necessary the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards (HSC §39500 et seq.).

When the state's air pollution statutes were reorganized in the mid-1960s, local APCDs were required to be established in each county of the state (HSC §40000 et seq.). There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs), with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California (HSC §40200 et seq.).

Air pollution control districts and air quality management districts in California have principal responsibility for:

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

Each level of government has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project. The other air agencies having permitting authority for this project are shown inTable 5.1-45. The applicable federal LORS and compliance with these requirements are discussed in more detail in Subsection 5.1.7. An application for a Determination of Compliance will be filed with the MDAQMD at approximately the same time as the AFC is filed with the Commission. An application for an Acid Rain permit will be filed at approximately the same time as the AFC. An application for a federal operating permit (Title V permit) will be filed within 12 months of commencement of operation of the facility.

Table 5.1-45
Agency Contacts

Agency	Authority	Contact
Right-of-Way Grant	Bureau of Land Management	Cedric Perry, Bureau of Land Management 22835 Calle San Juan de Los Lagos Moreno Valley, CA 92553-9046 (951) 697-5200 cperry@blm.gov
Application for Certification	California Energy Commission	Pierre Martinez, California Energy Commission 1516 Ninth Street, Sacramento, CA 95814 (916) 651-3765 PMartine@energy.state.ca.us
United States Environmental Protection Agency Region 9	Prevention of Significant Deterioration Permit Issuance, Enforcement	Gerardo Rios, Chief Permits Office, EPA Region 9 75 Hawthorne Street, San Francisco, CA 94105 (415) 972-3974
California Air Resources Board	Regulatory Oversight	Mike Tollstrup, Chief, Project Assessment Branch California Air Resources Board 2020 L Street, Sacramento, CA 95814 (916) 322-6026

Table 5.1-45
Agency Contacts

Agency	Authority	Contact
Mojave Desert Air Quality Management District	Permit Issuance, Enforcement	Eldon Heaston, Executive Director Mojave Desert Air Quality Management District 14306 Park Avenue, Victorville, CA 92392 (760) 245-1661

5.1.9 Permits Required and Permit Schedule

Under Regulations II and XIII of its Rules and Regulations, MDAQMD regulates the construction, alteration, replacement, and operation of new stationary emissions sources and modifications to existing sources. In addition, pursuant to its Rule 1306 Electric Energy Generating Facilities, the District's Air Pollution Control Officer will conduct a Determination of Compliance (DOC) review upon receipt of the AFC for the Project. This DOC for the project will be provided by MDAQMD as part of the CEC review to confirm that the project will meet all of the District's rules and regulations. A preliminary DOC (PDOC) is expected within approximately 180 days after the District accepts the application as complete. The PDOC will be circulated for public comment, and a final DOC (FDOC) will be issued by the MDAQMD after comment has been considered and addressed. Upon approval of the AFC by the CEC with conditions incorporating the requirements of the FDOC, the FDOC will confer upon the applicant all of the rights and privileges of an Authority to Construct (ATC). The District will then assume responsibility for issuing and enforcing a Permit to Operate (PTO) for the Project. This permitting process allows the MDAQMD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls will be used. An ATC allows for the construction of the air pollution source and remains in effect until the PTO application is granted, denied, or canceled. Once the project has completed construction and commences operations, MDAQMD will require verification that the Project conforms to the ATC application and, following such verification, will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with all air quality standards and regulations.

The MDAQMD has also received delegation from EPA to administer the federal Title IV and Title V programs for sources in the MDAB. The Project will be exempt from many of the acid rain program requirements, but the Project will be required to estimate SO_2 and CO_2 emissions from the project and to monitor NO_x and O_2 emissions with a certified CEMS, and will submit an acid rain permit application 24 months prior to commencement of operation pursuant to MDAQMD Rule 1210. The Rio Mesa SEGF must also submit a Title V permit application within 12 months after commencement of plant operation pursuant to MDAQMD Regulation XII.

Table 5.1-46
Permits and Permit Schedule

Permit	Agency Contact	Permit Schedule

Table 5.1-46
Permits and Permit Schedule

Permit	Agency Contact	Permit Schedule
Determination of Compliance (DOC) with conditions limiting emissions.	Eldon Heaston, Executive Director Mojave Desert Air Quality Management District (MDAQMD)	Agency approval to be obtained before start of construction.
Acid Rain program requirements included in Determination of Compliance, Permit to Operate, and Title V permit.	Eldon Heaston, Executive Director MDAQMD	Meet compliance deadlines listed in regulations.
Title V permit after review of application.	Eldon Heaston, Executive Director MDAQMD	Permit application to be submitted within 12 months after commencement of operation.
DOC with conditions limiting emissions.	Eldon Heaston, Executive Director MDAQMD	Screening Health Risk Assessment (HRA) submitted as part of AFC. Agency approval to be obtained before start of construction.
Final Certification with conditions limiting emissions.	Pierre Martinez, Project Manager California Energy Commission (CEC)	MDAQMD issuance of DOC precedes CEC approval of AFC.
Issues Title V permit after review of application.	Eldon Heaston, Executive Director MDAQMD	Application to be made within 12 months of start of facility operation.
Title IV requirements included in DOC, Permit to Operate, and Title V permit.	Eldon Heaston, Executive Director MDAQMD	Application to be made 24 months before start of facility operation.

Notes:
AFC = Application for Certification
DOC = Determination of Compliance
CEC = California Energy Commission
HRA = Health Risk Assessment
MDAQMD = Mojave Air Quality Management District

5.1.10 References

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U.S. Environmental Protection Agency (EPA). 2010b. OAQPS, Memo from Tyler Fox, Leader, Air Quality Modeling Group, to EPA Regional Air Division Directors, "Applicability of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard," June 28, 2010.

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Figure 5.1-1
2006-2010 Annual Wind Rose -- Blythe, CA #23158

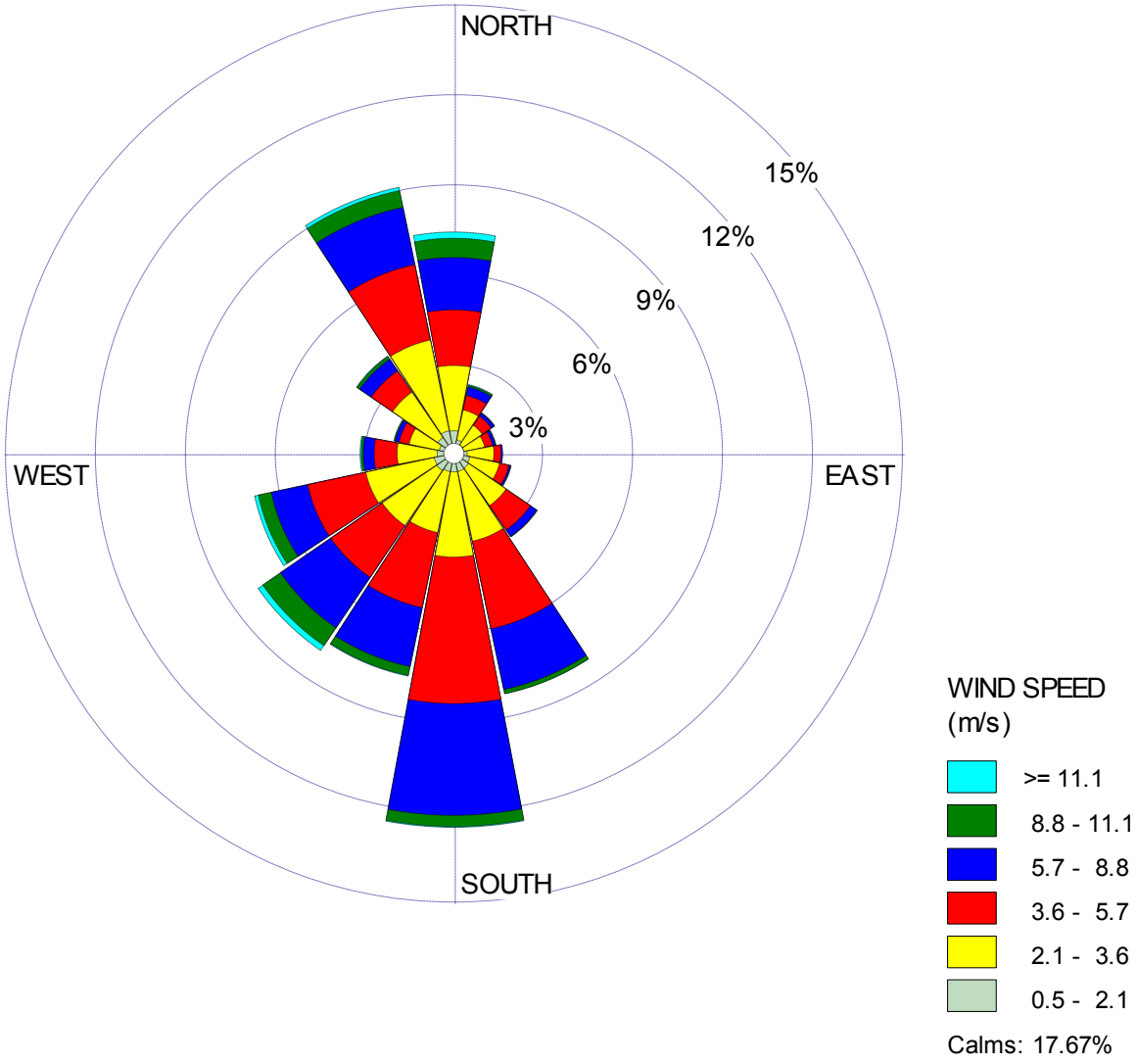


Figure 5.1-2
2006-2010 First Quarter Wind Rose -- Blythe, CA #23158

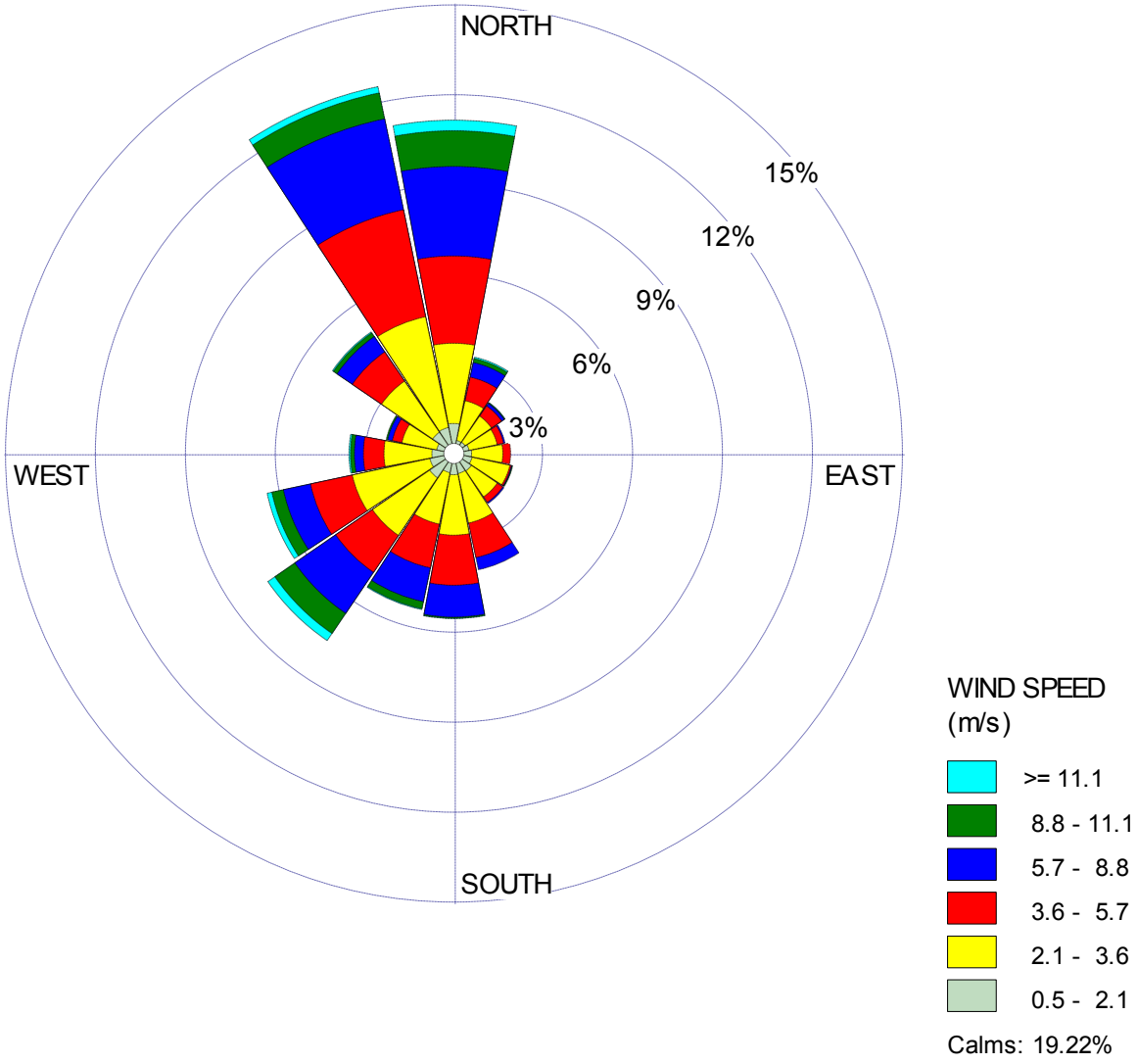


Figure 5.1-3
2006-2010 Second Quarter Wind Rose -- Blythe, CA #23158

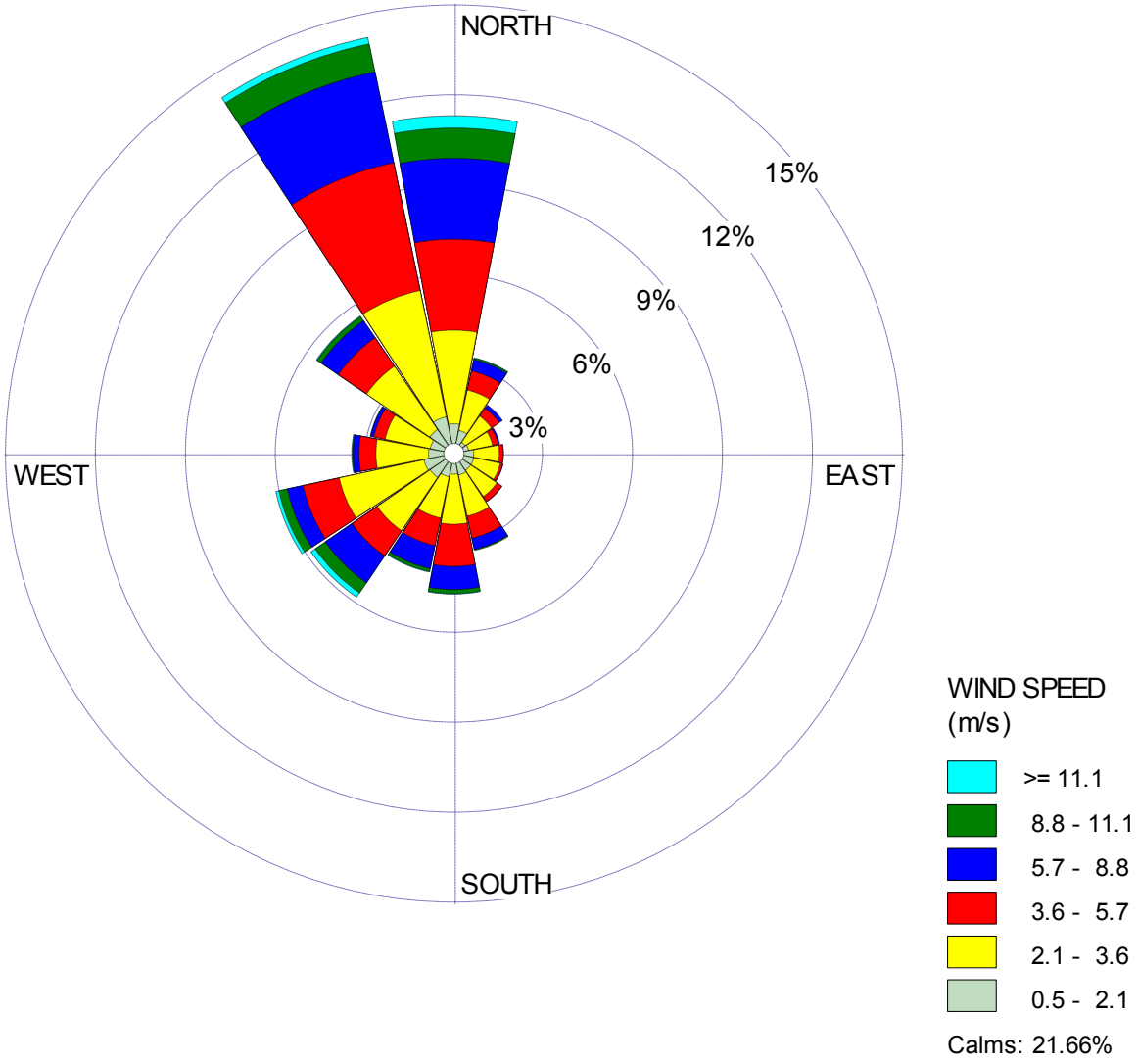


Figure 5.1-4
2006-2010 Third Quarter Wind Rose -- Blythe, CA #23158

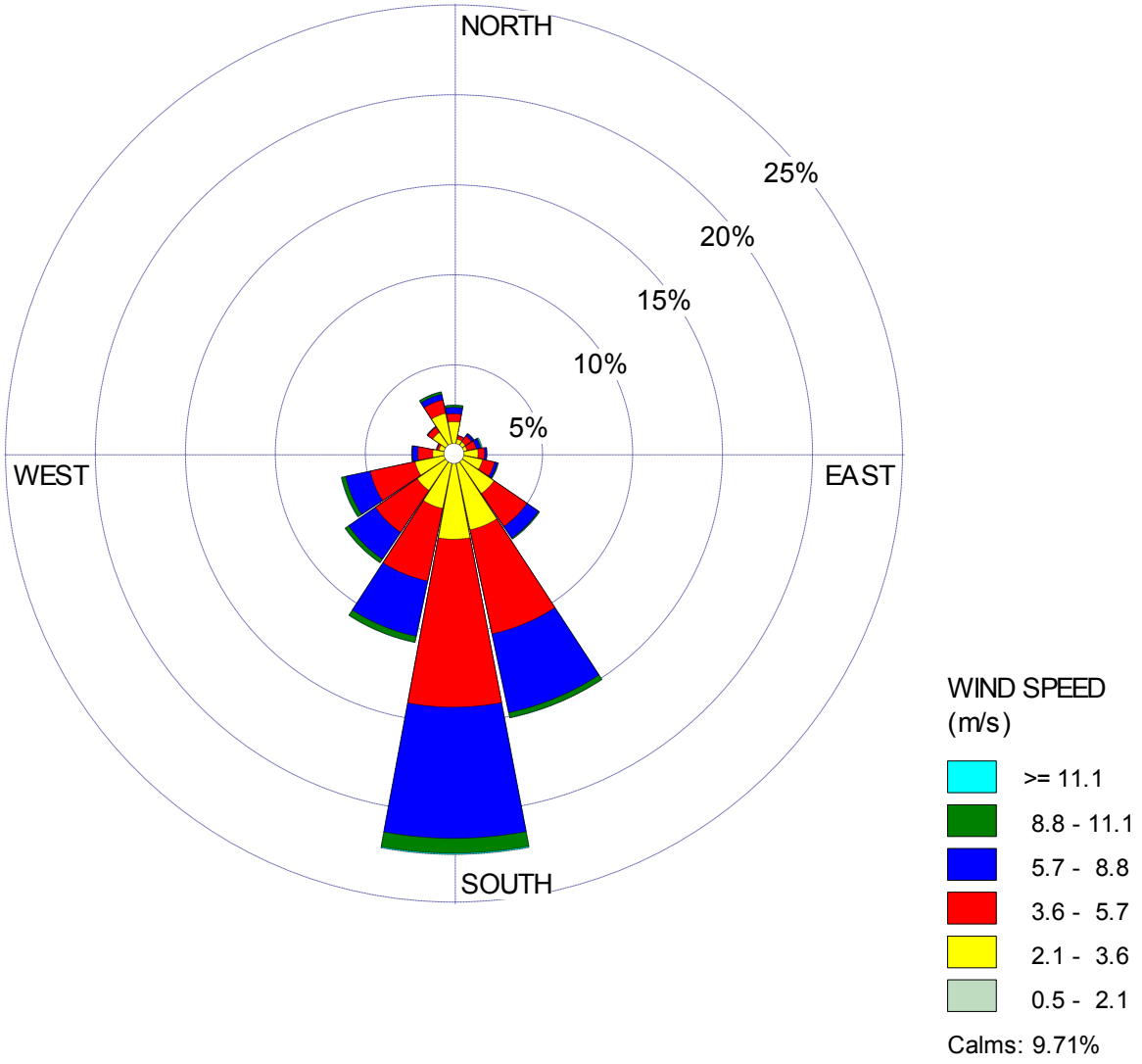


Figure 5.1-5
2006-2010 Fourth Quarter Wind Rose -- Blythe, CA #23158

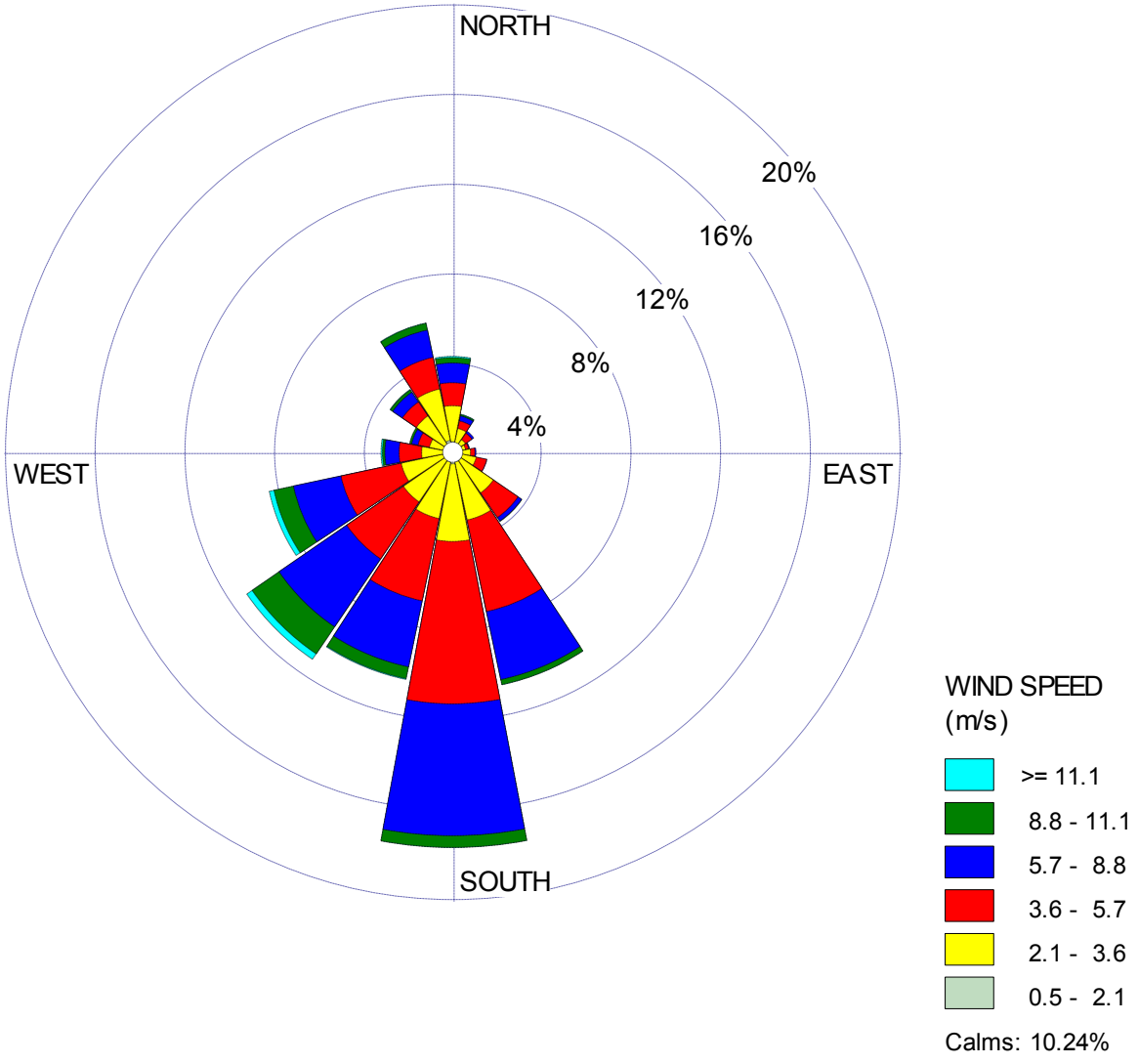
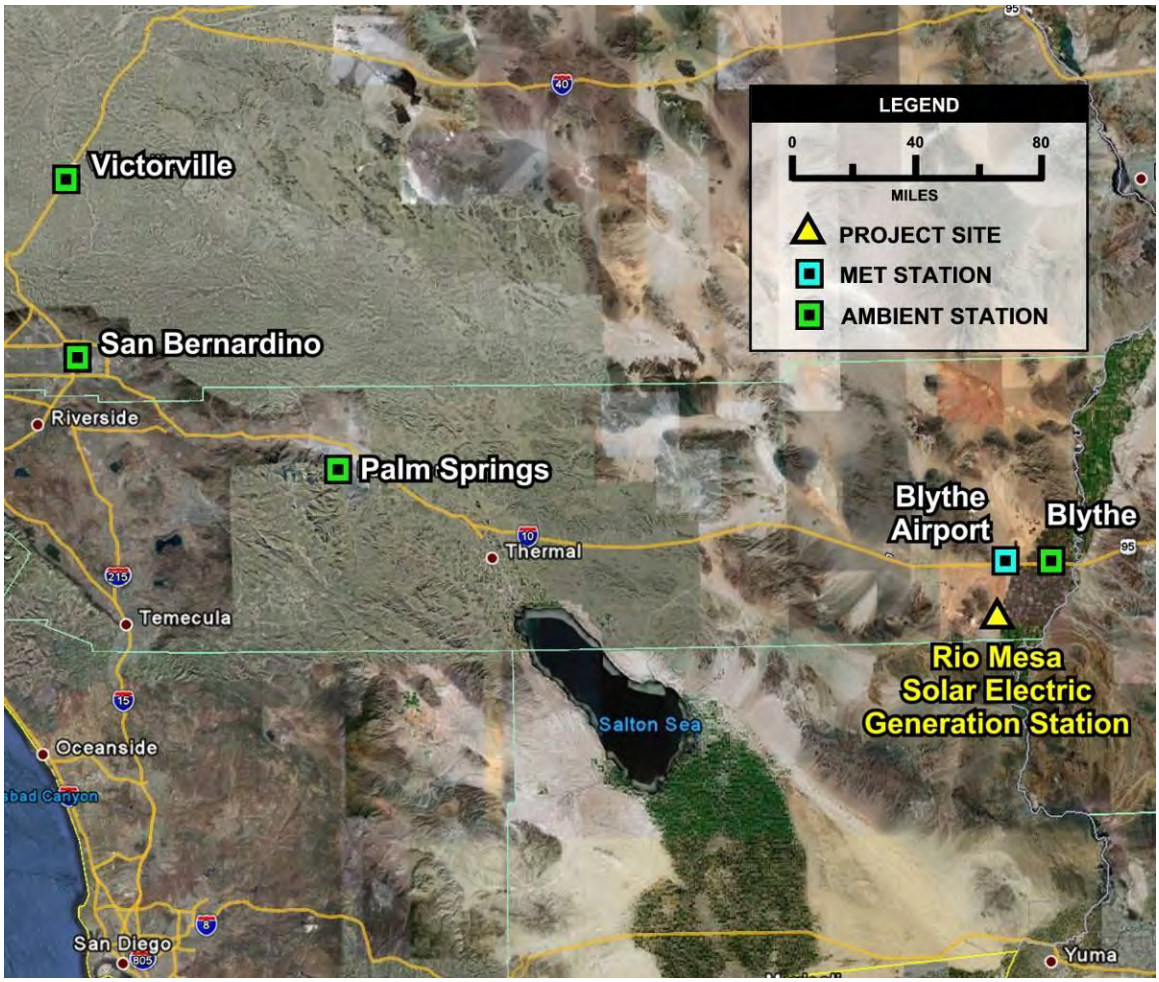


Figure 5.1-6
Relative Locations of the Project and Monitoring Stations



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DATA ADEQUACY WORKSHEET

Revision No. 0 Date ____

Technical Area: **Air Quality** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (1)	...provide a discussion of the existing site conditions, the expected direct, indirect and cumulative impacts due to the construction, operation and maintenance of the project, the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation.	Section 5.1.3 (pages 5.1-19 to 5.1-29) Section 5.1.5 (pages 5.1-65 to 5.1-68) Section 5.1.7 (pages 5.1-75 to 5.1-76)		
Appendix B (g) (8) (A)	The information necessary for the air pollution control district where the project is located to complete a Determination of Compliance.	Section 5.1.3 (pages 5.1-19 to 5.1-29) Section 5.1.5 (pages 5.1-65 to 5.1-68) Section 5.1.7 (pages 5.1-75 to 5.1-76) Section 5.1.8 (pages 5.1-76 to 5.1-78) Appendix 5.1 Enclosed modeling CD		
Appendix B (g) (8) (B)	The heating value and chemical characteristics of the proposed fuels, the stack height and diameter, the exhaust velocity and temperature, the heat rate and the expected capacity factor of the proposed facility.	Section 5.1.5 (pages 5.1-65 to 5.1-68) Table 5.1-16 Appendix 5.1B (Tables 5.1B-1 to 5.1B-7, Tables 5.1B-8, 5.1B-11) Appendix 5.1D (Tables 5.1D-2 to 5.1D-4)		
Appendix B (g) (8) (C)	A description of the control technologies proposed to limit the emission of criteria pollutants.	Section 5.1.5 (pages 5.1-65 to 5.1-68) Appendix 5.1C		

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SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (8) (D)	A description of the cooling system, the estimated cooling tower drift rate, the rate of water flow through the cooling tower, and the maximum concentrations of total dissolved solids.	Appendix 5.1B (Table 5.1B-9)		
Appendix B (g) (8) (E)	The emission rates of criteria pollutants and greenhouse gases (CO2, CH4, N2O, and SF6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources.	Section 5.1.5.3 (pages 5.1-66 to 5.1-68) Appendix 5.1B		
Appendix B (g) (8) (F)(i)	A description of typical operational modes, and start-up and shutdown modes for the proposed project, including the estimated frequency of occurrence and duration of each mode, and estimated emission rate for each criteria pollutant during each mode.	Section 5.1.5.3 (pages 5.1-66 to 5.1-68) Appendix 5.1B		
Appendix B (g) (8) (F)(ii)	A description of the project's planned initial commissioning phase, which is the phase between the first firing of emissions sources and the commercial operations date, including the types and durations of equipment tests, criteria pollutant emissions, and monitoring techniques to be used during such tests.	Section 5.1.5.3 (pages 5.1-66 to 5.1-68) Appendix 5.1B (Table 5.1B-17)		
Appendix B (g) (8) (G)	The ambient concentrations of all criteria pollutants for the previous three years as measured at the three Air Resources Board certified monitoring stations located closest to the project site, and an analysis of whether this data is representative of conditions at the project site. The applicant may substitute an explanation as to why information from one, two, or all stations is either not available or unnecessary.	Section 5.1.4.5 (pages 5.1-50 to 5.1-63)		

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SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (8) (H)	One year of meteorological data collected from either the Federal Aviation Administration Class 1 station nearest to the project or from the project site, or meteorological data approved by the California Air Resources Board or the local air pollution control district.	Section 5.1.4.5 (pages 5.1-54 to 5.1-56)		
Appendix B (g) (8) (H) (i)	If the data is collected from the project site, the applicant shall demonstrate compliance with the requirements of the U.S. Environmental Protection Agency document entitled "On-Site Meteorological Program Guidance for Regulatory Modeling Applications" (EPA - 450/4-87-013 (August 1995)), which is incorporated by reference in its entirety.	Not Applicable		
Appendix B (g) (8) (H) (ii)	The data shall include quarterly wind tables and wind roses, ambient temperatures, relative humidity, stability and mixing heights, upper atmospheric air data, and an analysis of whether this data is representative of conditions at the project site.	Section 5.1.4.5 (pages 5.1-54 to 5.1-56) Appendix 5.1A Enclosed modeling CD		
Appendix B (g) (8) (I)	An evaluation of the project's direct and cumulative air quality impacts, consisting of the following:	Sections 5.1.5 (pages 5.1-65 to 5.1-68) Section 5.1.7 (pages 5.1-75 to 5.1-76)		
Appendix B (g) (8) (I) (i)	A screening level air quality modeling analysis, or a more detailed modeling analysis if so desired by the applicant, of the direct criteria pollutant impacts of project construction activities on ambient air quality conditions, including fugitive dust (PM_{10}) emissions from grading, excavation and site disturbance, as well as the combustion emissions [nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter (PM2.5)] from construction-related equipment;	Section 5.1.4.5 (pages 5.1-57 to 5.1-58) Appendix 5.1F		

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SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (8) (I) (ii)	A screening level air quality modeling analysis, or a more detailed modeling analysis if so desired by the applicant, of the direct criteria pollutant (NO_x, SO_2, CO, PM_{10}, and $PM_{2.5}$) impacts on ambient air quality conditions of the project during typical (normal) operation, and during shutdown and startup modes of operation. Identify and include in the modeling of each operating mode the estimated maximum emissions rates and the assumed meteorological conditions;	Section 5.1.4.5 (pages 5.1-58 to 5.1-59) Appendix 5.1D		
Appendix B (g) (8) (I) (iii)	A protocol for a cumulative air quality modeling impacts analysis of the project's typical operating mode in combination with other stationary emissions sources within a six mile radius which have received construction permits but are not yet operational, or are in the permitting process. The cumulative inert pollutant impact analysis should assess whether estimated emissions concentrations will cause or contribute to a violation of any ambient air quality standard; and	Section 5.1.5 (pages 5.1-65 to 5.1-68) Appendix 5.1G		
Appendix B (g) (8) (I) (iv)	An air dispersion modeling analysis of the impacts of the initial commissioning phase emissions on state and federal ambient air quality standards for NO_X, SO_2, CO, PM_{10}, and $PM_{2.5}$.	Section 5.1.4.5 (page 5.1-63)		
Appendix B (g) (8) (J)	If an emission offset strategy is proposed to mitigate the project's impacts under subsection (g)(1), provide the following information:	Not applicable		
Appendix B (g) (8) (J) (i)	The quantity of offsets or emission reductions that are needed to satisfy air permitting requirements of local permitting agencies (such as the air district), state and federal oversight air agencies, and the California Energy Commission. Identify by criteria air pollutant, and if appropriate, greenhouse gas; and	Not applicable		

Adequacy Issue: Adequate ____ Inadequate ____

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Revision No. 0 Date ____

Technical Area: **Air Quality** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (8) (J) (ii)	Potential offset sources, including location, and quantity of emission reductions;	Not applicable		
Appendix B (g) (8) (K)	A detailed description of the mitigation, if any, which an applicant may propose, for all projects impacts from criteria pollutants that currently exceed state or federal ambient air quality standards, but are not subject to offset requirements under the district's new source review rule.	Section 5.1.7 (pages 5.1-75 to 5.1-76)		
Appendix B (i) (1) (A)	Tables which identify laws, regulations, ordinances, standards, adopted local, regional, state, and federal land use plans, leases, and permits applicable to the proposed project, and a discussion of the applicability of, and conformance with each. The table or matrix shall explicitly reference pages in the application wherein conformance, with each law or standard during both construction and operation of the facility is discussed; and	Table 5.1-1 (pages 5.1-3 to 5.1-5)		
Appendix B (i) (1) (B)	Tables which identify each agency with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies which would have permit approval or enforcement authority, but for the exclusive authority of the commission to certify sites and related facilities.	Table 5.1-45 (pages 5.1-77 to 5.1-78)		
Appendix B (i) (2)	The name, title, phone number, address (required), and email address (if known), of an official who was contacted within each agency, and also provide the name of the official who will serve as a contact person for Commission staff.	Table 5.1-45 (pages 5.1-77 to 5.1-78)		

Adequacy Issue: Adequate ____ Inadequate ____

DATA ADEQUACY WORKSHEET

Revision No. 0 Date ____

Technical Area: **Air Quality** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (i) (3)	A schedule indicating when permits outside the authority of the commission will be obtained and the steps the applicant has taken or plans to take to obtain such permits.	Section 5.1.9 (pages 5.1-78 to 5.1-79)		