5.2 Air Quality

Air quality issues for the Amended fall into two major categories: Operation and construction. Air emissions are expected to include “criteria” pollutants (those pollutants for which there is an ambient air quality standard), including nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), reactive organic compounds (ROC), respirable particulate matter (PM10), and fine particulate matter (PM2.5); toxic air contaminants (TAC), including chemical substances in the brine, byproducts of fuel (propane) combustion, diesel particulate matter from diesel fuel combustion; both organic and inorganic compounds from the operation of the cooling tower; and greenhouse gas (GHG) emissions from fuel combustion and brine. This section evaluates air emissions of criteria pollutants and GHG emissions. TAC emissions are evaluated separately in Section 5.10, Public Health.

The transmission lines that will interconnect the Project with the regional grid are already licensed and the Amended Project does not propose any changes to them. Thus, the transmission lines are not part of the Amendment Petition (AP) and are not discussed in this section.

5.2.1 Summary of Differences between Amended Project and Original SSU6

The original SSU6 project emissions were produced by multiple vent tanks, dilution water heaters, and handling and disposal of silica and sulfur filter cake. The Amended Project will not require dilution water heaters or the handling or disposal of large amounts of filter cake. This is because the Amended Project’s single flash technology maintains the heat energy of the brine at a sufficiently high level such that the silica stays in solution. Therefore, fugitive emissions associated with filter cake management will no longer occur. Single flash technology also is inherently less complicated from a material process standpoint. It eliminates the need for equipment such as crystallizers and clarifiers associated with multiple flash technology, which, in turn, greatly reduces the number of tank vents and other fugitive sources.

The original SSU6 project proposed LO-CAT plus Sulfurite technology to control hydrogen sulfide (H_2S) in noncondensable gas (NCG). The LO-CAT plus Sulfurite system would have generated approximately three tons per day of sulfur that would have required offsite disposal. LO-CAT/Sulfurite would not have controlled reactive organic compounds (ROC), benzene (a hazardous air pollutant [HAP]), or methane (a potent GHG). The Applicant proposed an activated carbon adsorption system to augment the LO-CAT/Sulfurite system, which would have controlled benzene and ROC emissions. Regeneration and/or replacement of the activated carbon would have resulted in air emissions from indirect sources from the regeneration process and transportation of waste offsite.

The Amended Project will employ a recuperative thermal oxidizer (RTO), instead of the LO-CAT/Sulfurite/activated carbon system, to control H_2S and other constituents of the NCG. The RTO uses an efficient combustion technology to oxidize both the H_2S as well as the ROC in the NCG stream. As a result, benzene, methane, and other organic species are controlled. The H_2S forms sulfur dioxide (SO_2) gas, which will be controlled in a wet scrubber downstream of the RTO. The SO_2 gas will be neutralized chemically to form water soluble salts, which become dissolved in the scrubber water. The scrubber blowdown will be injected into the geothermal brine source, helping to preserve the resource.

The original project also proposed a biological oxidation process operated in one cell of the cooling tower to control H_2S emissions in the condensate makeup water. The Amended Project will instead install a chemical oxidation process (referred to as "ChemOx") with a substantially higher control efficiency and operational reliability to control H_2S emissions.

The RTO/ChemOx system substantially reduces ambient air quality impacts associated with H_2S emissions compared to the original project. In fact, air emissions modeling performed for normal operations indicates that the Amended Project will not contribute to an exceedance of the 42 microgram per cubic meter ($\mu g/m^3$) California ambient air quality standard (CAAQS) for H_2S. As discussed below, the emission control systems proposed for control of H_2S and other NCGs from the Amended Project have been engineered so as to allow for a monitored, steady state operation, which will allow for consistency with respect to the quality of emissions from the power blocks that comprise the Amended Project. Testing of the emissions control systems, which are required by the Conditions of Certification (COCs) described below, will be sufficient to ensure that emissions are within applicable limits. Therefore, the Applicant proposes to omit the COC (AQ-29) for the original project associated with the development and operation of a meteorological monitoring station.

The Applicant is predicting a 70 percent reduction in ammonia emissions from the Amended Project compared to the original project. The reduction in emissions is attributed to the caustic scrubber following the RTO; ammonia in the NCG will be absorbed in the caustic scrubbing solution and will be injected into the formation with the scrubber blowdown.

The Amended Project will install Tier 4 diesel-fired engines to drive the emergency fire water pump and emergency generators. Tier 4 engines have substantially lower emission rates of criteria pollutants than the Tier 2 engines proposed for the original project.

The original project demonstrated via modeling significant unavoidable impacts to ambient air quality during project construction. The Amended Project will have similar significant, unavoidable impacts, as the construction activities required for the Amended Project are similar to the original project. As demonstrated through modeling, the Amended Project normal operating emissions do not cause exceedances of ambient air quality standards for criteria pollutants, and thus does not cause a significant adverse impact.

The Amended Project will also substantially reduce one of two impacts identified with the original project: 1) plant-commissioning H_2S emissions had the potential to cause an exceedance of the California Ambient Air Quality Standards, and 2) significant secondary fine particulate (PM10 and PM2.5) formation from ammonia emissions. While the H_2S-related impact would not change substantially with the Amended Project, the potential impact from ammonia emissions is anticipated to be substantially reduced.

In short, compared to the original project, the Amended Project will yield: 1) lower impacts to ambient air quality from H_2S emissions; 2) insignificant changes to combustion emissions; 3) a minor reduction in PM10 emissions; 4) substantial reductions to methane emissions; 5) substantial reductions in secondary fine particulate matter from ammonia emissions; and 6) substantial reductions in emissions associated with the activities such as transport of waste and regeneration of spent carbon. No significant changes are expected in construction phase emissions or associated impacts.

The Amended Project will not change the original project's impact conclusions with respect to ambient air quality modeling. However, the Applicant is recommending that the mitigation requirements for PM10 emissions outlined in the COC for the original project be eliminated because the PM10 emissions from the

Amended Project will not exceed the offset thresholds applicable to the Project location. In addition, because the Amended Project has lower impacts from H_2S emissions than the original project, and does not cause an exceedance of ambient air quality standards for H_2S from normal operations, the Applicant is recommending that the H_2S monitoring and mitigation requirements be eliminated.

5.2.2 LORS Compliance

Construction and operation of the Project will be performed in accordance with the applicable laws, ordinances, regulations and standards (LORS). The applicable Federal, State, and local air quality LORS are summarized in Table 5.2-1. In addition to the table, both applicable and some non-applicable LORS are briefly discussed following the table.

Table 5.2-1 Federal, State and Local LORS Applicable to Air Quality

LORS	Applicability	Where Discussed in AP Petition
Federal		
Clean Air Act (CAA) §111, 42 United States Code (USC) §7411; 40 Code of Federal Regulations (CFR) Part 60 - New Source Performance Standards (NSPS), Subpart A	Establishes the monitoring, reporting, and recordkeeping requirements for sources subject to NSPS standards.	Section 5.2.2
CAA §111, 42 USC §7411; 40 CFR Part 60 - NSPS, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	Establishes emission standards for compression ignition internal combustion engines, including emergency fire water pump engine and emergency electrical generator engines.	Section 5.2.2
State		
Title 17 California Code of Regulations (CCR) §93115, Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines	Establishes emission limits, operating limits, fuel use restrictions, monitoring and recordkeeping requirements on stationary compression ignition engines, including emergency fire water pump engine and emergency electrical generator engines.	Section 5.2.2
Assembly Bill (AB) 32 California Global Warming Solutions Act of 2006	Provides the statutory foundation for State-wide GHG reduction measures.	Section 5.2.2
Senate Bill (SB) 1368, Greenhouse Gas Emissions Performance Standard	Sets emission performance standards for GHG emissions per unit of power output.	Section 5.2.2

Table 5.2-1 Federal, State and Local LORS Applicable to Air Quality

LORS	Applicability	Where Discussed in AP Petition
Title 13 CCR, Article 4.8, Chapter 9, §§2449 *et seq*., In-Use Off-Road Diesel-Fueled Fleets	Regulation requires private and government owners of self-propelled, diesel-powered off-road vehicle fleets (e.g., forklifts, loaders, tractors, workover rigs, airport ground support), with a combined fleet power rating of more than 2,501 Hp, to have a written idling policy that is made available to vehicle operators and informs them that idling is limited to five consecutive minutes.	Section 5.2.2
Local - Imperial County Air Pollution Control District (ICAPCD)		
Rule 109 – Source Sampling	Establishes the requirement to provide and maintain such facilities as are necessary for sampling and testing.	Section 5.2.2
Rule 111 – Equipment Breakdown	Requires that the ICAPCD be notified of any occurrence which constitutes a breakdown condition within prescribed timeframes.	Section 5.2.2
Rule 201 – Permits Required	Requires permits to construct (ATC) and permits to operate (PTO) be obtained from the ICAPCD.	Section 5.2.2
Rule 202 - Exemptions	Provides list of equipment types that do not require permits.	Section 5.2.2
Rule 207 - New And Modified Stationary Source Review	Establishes the requirements that must be met to obtain an ATC including the requirement to comply with Best Available Control Technology (BACT), and provide emission offsets for emission increase above a specified threshold, modeling, an alternatives analysis, and a compliance certification.	Sections 5.2.2; 5.2.4, 5.2.5
Rule 208 – Permit to Operate	Provides the process by which a facility with an ATC may receive an approved PTO.	Section 5.2.2
Rule 216 - Construction or Reconstruction of Major Stationary Sources that Emit Hazardous Air Pollutants	Requires major sources of hazardous air pollutants to install Best Available Control Technology for Toxics (T-BACT).	Section 5.2.2
Rule 301 Permit Fees	Specifies types and amounts of fees payable by a facility.	Section 5.2.2
Rule 400 – Fuel Burning Equipment – Oxides of Nitrogen	Limits NOx discharges into the atmosphere from any non-mobile fuel burning equipment to 140 pounds per hour (lbs/hr) and establishes test requirements.	Section 5.2.2
Rule 401 – Opacity of Emissions	Limits visible emissions.	Section 5.2.2

Table 5.2-1 Federal, State and Local LORS Applicable to Air Quality

LORS	Applicability	Where Discussed in AP Petition
Rule 403 – General Limitations on the Discharge of Air Contaminants	Limits discharge of combustion contaminants, including lead, into the atmosphere from equipment to specified amounts.	Section 5.2.2
Rule 405 - Sulfur Compounds Emission Standards, Limitations and Prohibitions	Limits discharge of sulfur compounds into the atmosphere from equipment to specified amounts.	Section 5.2.2
Rule 407 - Nuisance	Prohibits the discharge of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which 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.	Section 5.2.2
Rule 414 - Storage of Reactive Organic Compound Liquids	Establishes control and inspection requirements applicable to storage tanks with a capacity equal to or greater than 1,500 gallons used to store ROC liquids with a true vapor pressure equal to or greater than 0.50 pounds per square inch absolute (psia).	Section 5.2.2
Rule 417 - Organic Solvents	Limits emissions of ROCs into the atmosphere from all ROC-containing materials not subject to source specific rules to 40 pounds per day (lbs/day) and 8 lbs/hr per device.	Section 5.2.2
Rule 418 - Disposal and Evaporation of Solvents	Limits disposal of photochemically reactive solvents to 1.5 gallons per day.	Section 5.2.2
Rule 424 - Architectural Coatings	Limits ROC emissions from architectural coatings.	Section 5.2.2
Rule 800 - General Requirements for Control of Fine Particulate Matter (PM10)	Limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and man-made conditions resulting in wind erosion.	Section 5.2.2
Rule 801 - Construction and Earthmoving Activities	Limits fugitive emissions from certain earthmoving, construction and demolition, and man-made conditions resulting in wind erosion.	Section 5.2.2
Rule 802 - Bulk Materials	Limits fugitive emissions from certain bulk storage conditions resulting in wind erosion.	Section 5.2.2
Rule 803 - Carry-Out and Track-Out	Requires use of specified measures to control emissions from vehicles that could carry-out or track-out dust from unpaved areas onto paved roads.	Section 5.2.2
Rule 804 - Open Areas	Requires use of dust suppression techniques in specified open areas.	Section 5.2.2

Table 5.2-1 Federal, State and Local LORS Applicable to Air Quality

LORS	Applicability	Where Discussed in AP Petition
Rule 805 - Paved and Unpaved Roads	Requires use of specified control techniques when constructing and using paved or unpaved roads.	Section 5.2.2
Rule 1101 - NSPS	Incorporates by reference the applicable requirements of all NSPS.	Section 5.2.2
ICAPCD CEQA Air Quality Handbook	Provides guidance on how to demonstrate compliance with CEQA for projects involving potential air quality impacts; guidelines specify daily mass-based significance thresholds for both construction and operations.	Sections 5.2.2 and 5.2.5

5.2.2.1 Federal LORS

The U.S. Environmental Protection Agency (EPA) is responsible for establishing the National Ambient Air Quality Standards (NAAQS) and enforcing the Federal CAA. Various Federal programs have been developed to regulate sources of air pollutants, including stationary, mobile and area sources. These programs include New Source Review (NSR) and other permitting requirements, as well as emissions standards for new and modified sources. Some of these Federal programs have been delegated to the ICAPCD for implementation in the local area.

Federal Programs

There are several Federal permitting and CAA programs that are applicable to major sources of emissions. However, as the Project will not be a major source, these programs, including the Prevention of Significant Deterioration regulations, the Operating Permits Program under Title V of the CAA Amendments of 1990, and the National Emission Standards for Hazardous Air Pollutants (NESHAP) for major sources (which are codified at 40 CFR Parts 61 and 63) are not applicable to the proposed Project

EPA has delegated authority to the ICAPCD to implement and enforce most of the Federal requirements that are applicable to the Project, including the NSPS and NESHAP for area sources. Compliance with the ICAPCD regulations ensures compliance and consistency with the corresponding Federal requirements as well.

New Source Performance Standards

NSPS are Federal standards promulgated for new and modified sources in designated categories codified in 40 CFR Part 60. NSPS are emission standards that are progressively tightened over time in order to achieve ongoing air quality improvement without unreasonable economic disruption. The NSPS impose uniform requirements on new and modified sources throughout the nation. These standards are based on the best demonstrated technology (BDT) for emission control. BDT refers to the best system of continuous emissions reduction that has been demonstrated to work in a given industry, considering economic costs and other factors, such as energy use. In other words, a new source of air pollution must install the best control system currently in use within that industry.

The format of the standard can vary from source to source. It can be a numerical emission limit, a design standard, an equipment standard, or a work practice standard. Primary enforcement responsibility of the NSPS rests with EPA, but this authority can be delegated to the states or local air districts. States can adopt an NSPS or impose limitations of their own, as long as the state requirements are at least as stringent as the Federal requirements. The NSPS potentially applicable to the Project are summarized below. Enforcement of the NSPS has been delegated to the ICAPCD.

Subpart A General Provisions

Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Because the Project is potentially subject to Subpart IIII, the requirements of Subpart A apply. The Project operator will comply with the applicable notifications, performance testing, recordkeeping, and reporting outlined in Subpart A.

Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence construction after July 11, 2005. Relevant to the proposed Project, the rule applies to the fire water pump CI engine and to the emergency electrical generator CI engine as follows:

(i) Non-fire pump engines manufactured after April 1, 2006;

(ii) Fire pump engines with less than 30 liters per cylinder manufactured after 2009; or

(iii) Fire pump engines manufactured as a certified National Fire Protection Association (NFPA) fire water pump engine after July 1, 2006.

For the purpose of this rule, “manufactured” means the date the owner places the order for the equipment. Based on the timeline projected for obtaining approval of the Project, the applicant expects that the engines will be ordered (and thus manufactured) in either 2010 or 2011.

Owners and operators of fire water pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards listed for all pollutants. For a model year 2009 or later, engines with a power rating between 175 and 300-horsepower (Hp), the limits are 2.6 grams per Hp-hour (g/Hp-hr) for CO, 3.0 g/Hp-hr for non-methane hydrocarbons (NMHC) and NOx combined, and 0.15 g/Hp-hr for PM. In model years 2009 through 2011, manufacturers of fire water pump stationary CI engines in this engine power category with a rated speed of greater than 2,650 revolutions per minute may comply with the emission limitations for 2008 model year engines. The Project will install an engine meeting these standards.

Owners and operators of non-fire pump engines must comply with the emission standards listed for all pollutants. For model years 2006 through 2010 engines with 750 or more Hp, the limits are 2.6 g/Hp-hr for CO, 4.8 g/Hp-hr for NMHC and NOx combined, and 0.15 g/Hp-hr for PM. The Project will install emergency generator engines that meet these standards.

5.2.2.2 State LORS

The California Air Resource Board (CARB) is responsible for ensuring implementation of the California Clean Air Act, meeting California requirements of the Federal CAA, and establishing CAAQS. It is also responsible for setting vehicle emission standards and fuel specifications, and for regulating emissions from other sources such as consumer products and certain types of mobile equipment (e.g., lawn and garden equipment, industrial forklifts). CARB also implements the California air toxic control measures (ATCM) and other air toxics programs, as discussed further in Section 5.10, Public Health.

Title 17, CCR §93115 Airborne Toxic Control Measure for Stationary Compression Ignition Engines

The California ATCM for CI engines specifies operating requirements and exhaust emission standards for stationary CI engines. Although this is an ATCM, it contains emission standards for criteria pollutants. In addition, it requires the use of CARB-specification diesel fuel (15 parts per million by weight [ppmw] sulfur).

To drive the fire water pump, the Applicant will install a new stationary CI engine that will meet the Tier 4 emissions standards for off-road engines and will limit the non-emergency hours of operation to the number of hours necessary to comply with the testing requirements of NFPA 25 "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 2002 edition, as required by the ATCM (17 CCR § 93115.6(a)(4)(A)(1)). The Project will limit the hours of operation of the fire water pump engine to one hour per week, not to exceed 50 hours per year, as recommended by NFPA 25, and will install a totalizing hour meter to substantiate compliance with the use limitation.

The Project will install six emergency generators. To drive these generators, the Applicant will install new stationary CI engines that will meet the Tier 4 emissions standards for off-road engines and will limit the non-emergency hours of operation to no more than 20 hours per year, and will install a totalizing hour meter on each engine to substantiate compliance with the use limitation.

The Project will use only CARB-specification diesel fuel in both the emergency generator and in the fire water pump engines and will retain purchase records and the Material Safety Data Sheet and/or technical data sheet to substantiate compliance with the 15 parts per million (ppm) fuel sulfur requirement.

AB 32 California Global Warming Solutions Act of 2006

California's major initiatives for reducing climate change or GHG emissions are outlined in AB 32 (signed into law in 2006); a 2005 Executive Order and a 2004 CARB regulation to reduce passenger car GHG emissions. These efforts aim at reducing GHG emissions to 1990 levels by 2020, a reduction of about 25 percent, and then an 80 percent reduction below 1990 levels by 2050. The main strategies for making these reductions are outlined in the Scoping Plan. The AB 32 Scoping Plan contains the main strategies California will use to reduce the GHG that cause climate change. The Scoping Plan has a range of GHG reduction actions which include direct regulations, alternative compliance mechanisms, monetary and non-monetary incentives, voluntary actions, and market-based mechanisms such as a cap-and-trade system. These measures have been introduced through four workshops between November 30, 2007 and April 17, 2008. A draft Scoping Plan was released for public review and comment on June 26, 2008 followed by more workshops in July, 2008. The Plan went to the Board for adoption in November, 2008. The Amended Project will comply with the requirements of these regulations when adopted.

SB 1368 GHG Emissions Performance Standard

On January 25, 2007, the California Public Utilities Commission (PUC) adopted an interim GHG Emissions Performance Standard (EPS). The EPS is a facility-based emissions standard requiring that all new long-term commitments for base-load 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 carbon dioxide (CO_2) per megawatt-hour. "New long-term commitment" refers to new plant investments (new construction), new or renewal contracts with a term of five years or more, or major investments by the utility in its existing base-load power plants.

The PUC implemented SB 1368 which prohibits load-serving entities (LSEs), including investor-owned utilities, energy service providers, and community choice aggregators, from entering into a long-term financial commitment for base-load generation unless it complies with a GHG emissions performance standard. To help mitigate climate change, the PUC has long anticipated capping GHG emissions in order to ensure LSEs make long-term commitments to energy resources that have GHG emissions profiles that are at least as clean as California's existing portfolio. The PUC approved a policy statement indicating its intent regarding GHG emissions in October 2005.

Since that time SB 1368 and AB 32 have been signed into law. The latter requires reporting and verification of State-wide GHG emissions. The PUC is implementing the EPS according to SB 1368 and may revisit the EPS once an emissions cap is operational in California as required by AB 32.

The PUC has jurisdiction over the energy commitments of investor-owned utilities. SB 1368 gives additional authority to the PUC to implement and enforce the EPS for electric service providers (competitive retail providers delivering energy to consumers within the service territories of the investor-owned utilities) as well as any potential community choice aggregators (CCAs) that may form in the future (there are currently no CCAs operating in California, though a number are in the planning stages). SB 1368 also grants specific authority to the California Energy Commission (CEC) to implement and enforce an EPS for the municipal utilities in California. The PUC and the CEC are working closely together to ensure that the standards adopted are as consistent as possible.

The EPS of 1,100 pounds of CO_2 per megawatt-hour is the baseline emission level developed for combined cycle gas turbine plants. As a geothermal plant with very few combustion sources, the Amended Project will emit 260 pounds per megawatt-hour, approximately one-quarter of the standard.

Health & Safety Code §39658, Maximum Achievable Control Technology Standards

Health & Safety (H&S) Code § 39658(b)(1) states that when EPA adopts a standard for a TAC pursuant to §112 of the Federal CAA (42 USC § 7412), such standard becomes the ATCM for the TAC. Once an ATCM has been adopted it becomes enforceable by the ICAPCD 120 days after adoption or implementation (H&S Code § 39666(d)). EPA has not to date adopted a Maximum Achievable Control Technology (MACT) standard that is applicable to the proposed Project. Should EPA adopt an applicable MACT standard in the future, the ICAPCD will be required to enforce said MACT as an ATCM on the proposed Project. MACT is also required for each major source of TAC. As shown in Section 5.10, Public Health, and Appendix E.3, Air Emission Calculations, the Amended Project will not emit more than 10 tons per year (tpy) of any individual TAC, and will not collectively emit more than 25 tpy of all TAC; therefore, MACT is not required.

<u>Title 13 CCR, Article 4.8, Chapter 9, §2449 *et seq*., In-Use Off-Road Diesel-Fueled Fleets</u>

Effective March 1, 2009, CARB regulations will require private and government owners of self-propelled, diesel-powered off-road vehicle fleets (e.g., forklifts, loaders, tractors, workover rigs, airport ground support), with a combined fleet power rating of more than 2,501 Hp, to have a written idling policy that is made available to vehicle operators and informs them that idling is limited to five consecutive minutes. The policy must include, at a minimum, the following elements as outlined by the regulation:

- Description of idling limitations,
- Applicable vehicle list,
- Non-compliance reporting contact information,
- Regulation language,
- Exemptions, and
- Description of potential penalties.

There are monetary penalties for not having a written policy. A training program is highly recommended, but not required by the regulation. In addition to the written policy, an initial report that includes applicable vehicles must be submitted. The deadline for large private fleets (>5,000 Hp) and state and federal fleets is April 1, 2009; for medium fleets (2,501 – 5,000 hp) is June 1, 2009; and for small fleets (0 – 2,500 Hp) is August 1, 2009. Annual updates will be required. Once the initial report is received, Equipment Identification Numbers (EIN) will be assigned by CARB and provided to the fleet owner. A label with the EIN must be affixed to the vehicle by the fleet owner within 30 days of receipt. Initial and annual update reporting can be completed online using on the Diesel Off-Road On-Line Reporting System (DOORS).

Construction of the Amended Project will involve a large number of diesel-fueled off-road vehicles, and thus it is possible that Project's construction contractor would be subject to this regulation. The Applicant will use a contractual mechanism to ensure that any construction contractor employed for the Project who is subject to this regulation complies with the regulation.

5.2.2.3 Local LORS

The local LORS are administered by the ICAPCD.

<u>Regulation I General Provisions</u>

ICAPCD Rule 109 Source Sampling

The permittee may be required to provide and maintain such facilities as are necessary for sampling and testing. In the event of such requirements, the ICAPCD shall notify the applicant in writing of the required size, number and location of sampling ports; the size and location of the sampling platform; the access to the sampling platform, and the utilities for operating the sampling and testing equipment. The platform and access shall be constructed in accordance with the General Industry Safety Orders of the State of California. The Project will provide such facilities upon request.

ICAPCD Rule 110 Stack Monitoring

The owner or operator shall provide, install, and maintain continuous monitoring systems to measure the specific pollutants from steam generators with heat input of 250 million British thermal units or more per hour. The Amended Project has no such equipment; therefore, this rule is not applicable.

ICAPCD Rule Equipment Breakdown

The owner or operator shall notify the ICAPCD of any occurrence which constitutes a breakdown condition. The owner or operator shall demonstrate the nature and extent of the breakdown by providing to the ICAPCD signed contemporaneous operating logs and/or other relevant evidence which shows that:

a) A statement that the occurrence has been corrected, together with the date of correction and proof of compliance;
b) A specific statement of the reason(s) or cause(s) from the occurrence sufficient to enable the ICAPCD to determine whether the occurrence was a breakdown condition;
c) A description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future;
d) An estimate of the emissions caused by the occurrence; and
e) Pictures of the equipment or controls which failed, if available.

Such relevant evidence shall be submitted to the ICAPCD within 10 days of the date the breakdown was reported to the ICAPCD. The Project will make such notifications and reports, as may become necessary.

Regulation II Permits

ICAPCD Rule 201 Permits Required

Any person building, altering or replacing any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate or reduce or control the issuance of air contaminants, must first obtain authorization for such construction from the ICAPCD. An ATC shall remain in effect until the PTO for the equipment for which the application was filed is granted, denied, or canceled. An air permit application for a Determination of Compliance (DOC; functionally equivalent to an ATC) will be submitted to the ICAPCD in a timely manner to satisfy this requirement.

ICAPCD Rule 202 Exemptions

The Project will employ a number of devices that emit air pollutants, but are exempt from permit pursuant to one or more exemptions listed in Rule 219, including seven diesel fuel storage tanks piped exclusively to emergency engines, a propane tank, heating ventilation and air conditioning systems, a water heater, water treatment systems, and storage tanks for water treatment chemicals.

ICAPCD Rule 207 New and Modified Stationary Source Review

Under Federal and California law, the ICAPCD is required to implement a NSR program that attains, or makes reasonable progress toward attaining, the NAAQS and CAAQS within the District. If the pollutant concentrations in ambient air exceed the standards, then the area is designated nonattainment, and offsets must be provided for major new sources or modifications to existing sources. The District is required to develop an Air Quality Management Plan (also referred to as a State Implementation Plan, which identifies rules and other measures that must be adopted to attain or maintain compliance with the NAAQS and CAAQS. ICAPCD Rule 207 is the cornerstone of this process within the District. This regulation provides the requirements, such as how offset calculations must be done and thresholds over which emissions must be offset. It also defines which pollutants must be offset, what ratios must be used, and the criteria of what can be used as an emission reduction credit (ERC). If a project meets the requirements of these rules, then the mitigation (i.e., ERC) can be considered to be completely effective since the program has been developed to ensure eventual attainment of the NAAQS and CAAQS.

Rule 207 provides for preconstruction review of new and modified stationary sources of affected pollutants to insure emissions will not interfere with attainment of NAAQS and CAAQS; ensures appropriate new and modified sources of affected pollutants are constructed with BACT; and provides for no significant net increase in emissions from new and modified stationary sources for all non-attainment pollutants and their precursors. Rule 207 addresses the specific requirements of BACT and offsets.

BACT: An applicant shall provide BACT for any new or modified permit unit which emits, or has the potential to emit, 25 lbs/day or more of any nonattainment air pollutant or its precursors; or any new or modified permit unit with a potential to emit equal to or greater than the values in Table 5.2-2.

Table 5.2-2 ICAPCD BACT Thresholds

Pollutant	BACT Threshold lbs/day
Carbon Monoxide	550
Lead	3.3
Asbestos	0.04
Beryllium	0.0022
Mercury	0.55
Vinyl chloride	5.5
Fluoride	16
Sulfuric acid mist	38
Hydrogen sulfide	55
Total Reduced Sulfur	55

The Salton Sea Air Basin (SSAB) is designated as a non-attainment area with respect to ozone and PM10 and attainment with respect to NOx, PM2.5, SO_2 and CO. Although the SSAB is in attainment with the ambient air quality standards for SO_2 and NOx, NOx is a precursor to ozone, and both SO_2 and NOx are precursors to PM10. There are no ambient air quality standards for ROC; however, ROC is a precursor to ozone. Therefore, SO_2, NOx and ROC are treated as non-attainment air pollutants as well. The net result is that BACT is required for ROC, NOx, SO_2, and PM10 if emissions of the specific pollutant exceed 25 lbs/day. Although ammonia (NH_3) is commonly considered a precursor to PM10, it is not regulated by ICAPCD, and there is no BACT threshold or emission limit applicable to NH_3. There will be several emission sources at the facility that will be required to employ current BACT. The manner in which the Amended Project will comply with BACT is addressed in more detail in Section 5.2.4, Control Technology Assessment.

Offsets: An applicant must provide offsets for new or modified stationary source of ROC, NOx, SOx, PM10, or CO for the source's potential to emit when the source's potential to emit equals or exceeds the offset trigger levels identified in the rule and shown in Table 5.2-3.

Table 5.2-3 ICAPCD Offset Thresholds

Pollutant	Offset Threshold lb/day
ROC	137
NOx	137
SOx	137
PM10	137
CO	137

As shown in Table 5.2-27, daily Project emissions do not exceed the offset threshold for any pollutant; thus offsets are not required for the Amended Project.

Additional Procedural Requirements Specified in Rule 207:

Alternative siting: For sources requiring an analysis of alternative sites, sizes, and production processes and environmental control techniques, pursuant to Section 173 of the Federal CAA, the applicant must prepare an analysis functionally equivalent to requirements of Division 13, Sections 21000 *et seq.* of the Public Resources Code.

Modeling: Emissions from a new or modified stationary source shall not make worse an exceedance of an NAAQS and CAAQS. In making this determination, the ICAPCD will take into account increases in cargo carrier and secondary emissions and offsets provided pursuant to this rule. The Project emissions exceed the offset trigger levels and, therefore, modeling is required for the Project. A modeling analysis is presented in Section 5.2.5.

Power Plants: The ICAPCD is required to prepare and submit a report to CARB and the CEC that includes:

a) A preliminary specific definition of BACT for the proposed facility;

b) A preliminary discussion of whether there is substantial likelihood that the requirements of this regulation and all other Air Pollution Control District rules and regulations can be satisfied by the proposed facility;

c) A preliminary list of conditions which the proposed facility must meet in order to comply with this regulation or any other applicable Air Pollution Control District rules or regulations.

The preliminary determinations contained in the report shall be as specific as possible within the constraints of the information contained in the Notice of Intention.

The preliminary BACT determination is provided in Section 5.2.4, Control Technology Assessment; compliance with the ICAPCD rules and regulations is addressed in Section 5.2.2.3, Local LORS; and the preliminary list of conditions is provided in Section 5.2.7, Conditions of Certification of this Amendment Petition

ICAPCD Rule 208 Permit to Operate

A person shall not operate or use any equipment, the use of which may cause the issuance of air contaminants, or the use of which may reduce or control the issuance of air contaminants, without first obtaining a written PTO from ICAPCD, or except as provided in Rule 202. The equipment shall not be operated contrary to the conditions specified in the permit to operate. The Project will comply with this rule by obtaining a permit from the ICAPCD in a timely manner and complying with the stated conditions.

ICAPCD Rule 216 Construction or Reconstruction of Major Stationary Sources that Emit Hazardous Air Pollutants

All owners and operators of stationary sources that emit HAPs are required to install T-BACT to any constructed or reconstructed major source. All T-BACT determinations shall be controlled to a level that is no less stringent than new source MACT as required by the CAA, §112 (g)(2)(B) and implemented through 40 CFR §63.40-63.44, of subpart B. The Project complies with this rule via implementation of the control devices identified in the Control Technology Assessment provided in Section 5.2.4.

Regulation III Fees

ICAPCD Rule 301 Permit Fees

Permit filing fees will be paid to the ICAPCD with the air permit application, and permit review fees will be paid upon receipt of an invoice.

Regulation IV Prohibitions

ICAPCD Rule 400 Fuel Burning Equipment – Oxides of Nitrogen

This rule applies to non-mobile fuel burning equipment, and limits NOx emissions to 140 lbs/hr. The project will have a RTO, a diesel-fueled emergency electrical generator and a diesel-fueled emergency fire pump engines. The diesel engines will be EPA and CARB certified, and the RTO will be designed to be low emitting. As shown in Table 5.2-21 hourly NOx emissions do not exceed 140 lbs/hr for the entire Project, thus, compliance with this rule is expected.

ICAPCD Rule 401 Opacity of Emissions

A person shall not discharge into the atmosphere, from any single source of emissions whatsoever, any air contaminant for a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade as that designated as No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke which is as dark or darker in shade as that designated as No. 1 on the Ringelmann Chart. The cooling towers will be equipped with BACT, the diesel engines will be EPA and CARB certified, and the RTO exhaust will pass through a scrubber. No other source is expected to produce visible emissions. Compliance with this rule is expected.

ICAPCD Rule 403 General Limitation on the Discharge of Air Contaminants

This rule limits discharges from any emission unit to the following:

1) Particulate matter, including lead and lead compounds, in excess of the rate specified in the rule;

2) Air contaminants in excess of the concentrations at standard conditions specified in the rule;

3) Combustion contaminants exceeding in concentration at the point of discharge of 0.2 grains per dry cubic foot of gas, calculated to 12 percent of CO_2 at standard conditions averaged over 25 consecutive minutes;

4) Combustion contaminants from new or existing stationary electrical utility generating units, excepting emergency standby generators, in concentrations at the point of discharge of 0.01 grains per dry standard cubic foot of gas, calculated to three percent excess oxygen (O_2) for boilers and 15 percent O_2 for gas turbines; and

5) Combustion contaminants derived from the fuel in excess of 10 lbs/hr from a new or existing stationary fuel burning equipment other than electrical utility generating units.

The cooling towers will be equipped with BACT, the diesel engines will be EPA and CARB certified, and the RTO exhaust will pass through a scrubber. As shown in Tables 5.2-21 and 5.2-23, stack emissions do not exceed rule limits, thus, compliance with this rule is expected.

ICAPCD Rule 405 Sulfur Compounds Emissions Standards, Limitations and Prohibitions

This rule limits discharges from any emission unit to the following:

1) Sulfur compounds, calculated as SO_2 in excess of 0.2 percent by volume;

2) Contaminants from any stationary fuel burning equipment, containing more than the following limits:

    a) 500 parts per million by volume (ppmv) of sulfur compounds calculated as SO_2, or

    b) 200 lbs/hr of sulfur compounds calculated as SO_2.

In addition, no gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as H_2S at standard conditions, and no liquid or solid fuel, or mixture thereof, containing sulfur in excess of 0.5 percent by weight, shall be burned.

The diesel fuel will meet CARB requirements. Propane is inherently a low sulfur content fuel. The H_2S content of the process stream is not expected to exceed the stated limit. Compliance with this rule is expected.

ICAPCD Rule 407 Nuisance

A person shall not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which 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. The cooling towers will be equipped with BACT, the diesel engines will be EPA and CARB certified, and the RTO exhaust will pass through a scrubber. Also, because of the distance from the emission sources to any potential receptors, compliance with this rule is expected.

ICAPCD Rule 413 Solvent Degreasers

This rule applies to all persons who own or operate remote reservoir cold cleaners, batch-loaded cold cleaners, open-top vapor degreasers, and all types of conveyorized degreasers that carry out solvent cleaning operations with a solvent containing ROCs. Solvent cleaning operations that are regulated by this rule include, but are not limited to, the removal of uncured coatings, adhesives, inks, and contaminants such as dirt, soil, oil, and grease from parts, products, tools, machinery, and equipment. The Project will comply with the requirements of this rule if such equipment is used at the facility.

ICAPCD Rule 414 Storage of Reactive Organic Compound Liquids

This rule applies to any storage tank with a capacity equal to or greater than 1,500 gallons used to store ROC liquids with a true vapor pressure equal to or greater than 0.50 psia. Propane, diesel fuel, various lubricating oils, and other maintenance fluids will stored at the facility. Except for the propane tanks, none of the fuel storage containers will exceed the threshold limit of 1,500 gallons and, therefore, will not be subject to this rule. The three, 2,000-gallon propane tanks will comply with Rule 414 by using pressure tanks which maintain sufficient pressures to prevent organic vapor loss to the atmosphere.

ICAPCD Rule 417 Organic Solvents

A person shall not discharge ROCs into the atmosphere from all ROC-containing materials, emissions units, equipment or processes subject to this rule, in excess of 40 lbs/day and eight lbs/hr from each source. At this time, the Applicant does not anticipate using any solvents subject to this rule, however, should the Project use any materials subject to this rule, it will document usage accordingly to ensure the emissions do not exceed the allowable limits.

ICAPCD Rule 418 Disposal and Evaporation of Solvents

A person shall not dispose of a total of more than 1.5 gallons of any photochemically reactive solvent or of any material containing more than 1.5 gallons of any such photochemically reactive solvent, by any means which will permit the evaporation of such solvent into the atmosphere. Should the Project use any materials subject to this rule, it will dispose of them properly.

ICAPCD Rule 424 Architectural Coatings

The purpose of this rule is to limit ROC emissions from architectural coatings. This rule specifies architectural coatings, storage, cleanup, and labeling requirements. The Project will comply with the requirements of this rule if architectural coatings are applied at the Project during construction or subsequent maintenance activities.

Regulation VIII-Fugitive Dust Rules

ICAPCD Rule 800 General Requirements for Control of PM10
ICAPCD Rule 801 Construction and Earthmoving Activities
ICAPCD Rule 802 Bulk Materials
ICAPCD Rule 803 Carry-Out and Track-Out
ICAPCD Rule 804 Open Areas
ICAPCD Rule 805 Pave and Unpaved Roads

The purpose of these rules is to reduce the amount of PM10 emitted from significant man-made fugitive dust sources and in an amount sufficient to maintain NAAQS. The provisions of these rules apply to specified bulk storage, earthmoving, construction and demolition, and man-made conditions resulting in wind erosion. The rules also apply to paved and unpaved roadways located in the District

Project construction will involve bulk storage of soils, earthmoving, construction and demolition, and man-made conditions that have the potential for fugitive dust emissions. The Project operator, or its contractors, will follow the fugitive dust control strategy outlined in a Dust Control Plan that will be prepared for the Project.

Project operation will involve routine vehicle travel within the property boundaries for maintenance purposes. This activity has the potential for fugitive dust emissions. The owner, or its contractors, will follow the fugitive dust control strategy outlined in the Dust Control Plan that will be prepared for the Project.

Regulation IX - Title V

As shown in Table 5.2-27, the Project will not be a major source of criteria air pollutants, and thus these standards are not applicable to the Project.

Regulation XI - New Source Performance Standards

ICAPCD Rule 1101 New Source Performance Standards

As discussed above, the Project will be subject to 40 CFR 60, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and it will comply by purchasing equipment that meets the applicable emission standards.

ICAPCD CEQA Air Quality Handbook

The handbook provides guidance on how to demonstrate compliance with CEQA for projects involving potential air quality impacts. The guidelines specify daily mass-based significance thresholds for both construction and operations. The specific thresholds are shown in Table 5.2-4.

Table 5.2-4 ICAPCD CEQA Significance Thresholds

Pollutant	Construction Threshold lbs/day	Operations Threshold lbs/day
NOx	100	55
ROC	75	55
PM10	150	150
SOx	---	150
CO	CO	55

For operation, when project emissions exceed the stated significance threshold, additional air quality impacts analysis (i.e., ambient air quality modeling) is required. Because ambient air quality modeling is presented in this Amendment Petition, Project emissions are not compared to significance thresholds.

As shown in Table 5.2-19, Project construction emissions exceed the construction significance thresholds for NOx, ROC, PM10 and CO. ICAPCD recognizes that construction impacts are short-term in nature and recommends a number of mitigation measures to reduce potential impacts. The Conditions of Certification listed in Section 5.2.7 incorporate the mitigation measures recommended by the District.

5.2.2.4 Involved Agencies

Under the CEC licensing process, the Project must obtain a DOC from the ICAPCD, (the DOC will contain all of the requirements normally contained within an ATC). Contact information for this agency is provided in Table 5.2-5.

Table 5.2-5 Agencies and Contacts

Agency Contact	Phone/email	Permits/Issue
Brad Poiriez Air Pollution Control Officer Imperial County APCD 150 S. 9th Street El Centro, CA 92243	(760) 482-4606 bradpoiriez@imperialcounty.net	Air permit (DOC/ATC)

5.2.2.5 Required Permits and Permit Schedule

Table 5.2.6 lists the air quality-related permits that are required for the Project. As noted above, under the CEC licensing process, the ICAPCD will issue a DOC; however, a DOC is equivalent to the ATC issued by the ICAPCD for other sources. Once the Project is built, the ICAPCD will issue a PTO in conjunction with the CEC license. This table also provides the schedule for when applications for these permits are needed.

Table 5.2-6 Permits Required and Permit Schedule

Permit/Approval	Schedule
DOC/ATC	In accordance with ICAPCD Rule 207, this AFC serves as an application for the DOC/ATC. The ICAPCD will work within the timeframes of the CEC's AFC process to issue the DOC.
PTO	Once the equipment becomes operational, a PTO must be obtained by the operator.

5.2.3 Affected Environment

The Project site is located approximately six miles northwest of Calipatria, southwest of the Salton Sea, near Obsidian Butte, at the northern end of the Imperial Valley, at an average elevation of 225 feet below mean sea level. Imperial Valley is a broad flat depression, centered about the Salton Sea, and flanked by mountains on the east (20 miles away) and west (24 miles away).

The site is currently used for agricultural production, and land uses in the surrounding area include existing geothermal power facilities, agriculture, and wildlife management, including the Sonny Bono Salton Sea National Wildlife Refuge. The closest residential land use to the Project site is located to the northeast, approximately 0.7 miles away (the Wildlife Refuge staff housing). The second closest residence is approximately two miles east of the site.

Imperial County has a desert climate that is characterized by low precipitation, hot summers, mild winters, low humidity and strong temperature inversions. 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 area. This high pressure ridge blocks out most mid-latitude storms, except in winter when the high is weakest and the farthest south. The coastal mountains on the western edge of the Imperial Valley also have a major influence on climatic conditions by blocking the cool, damp marine air found in the California coastal environs. The flat terrain of the valley floor in the Salton Sea area and the strong temperature differentials created by intense solar heating produces moderate winds and deep thermal convection currents. The combination of subsiding air, protective mountains, and distance from the ocean all combine to severely limit precipitation. The valley area experiences surface inversions almost every day of the year. These inversions are usually broken by solar heating. Strong, persistent subsidence inversions, caused by the presence of a Pacific high pressure system, can persist for one or more days, causing air stagnation conditions. Temperature and precipitation data from the nearest representative local cooperative station, Brawley 2 SW, over a 97-year record, 1910-2007, are used to define climatic normal, means and extremes. The hottest month, July, has an average maximum temperature of 107.6 degrees Fahrenheit (°F), an average minimum temperature of 75.2° F, and an average mean temperature of 91.4° F. The coldest month, December, has an average maximum temperature of 69.9° F, average minimum temperature of 39.2° F, and average mean temperature of 54.6° F. Annual average rainfall for this same period was 2.65 inches. The wettest month is December, averaging 0.46 inches; the driest month, June, averages 0.01 inches. Rainfall is highly variable with precipitation from a single heavy storm potentially exceeding the entire annual total rainfall during a drought year. Humidity levels have not been recorded at Brawley 2 SW.

5.2.3.1 Meteorological Data

For air quality impact analyses, hourly meteorological data are needed for modeling purposes. Hourly surface meteorological data characteristic of the Project site was obtained from the National Weather Bureau Army Navy (WBAN) station at Imperial County Airport Station. The airport meteorological tower is located approximately 25 miles south of the Project site. Five years of data for the years 2002 through 2006 were used in the impact analyses. Other WBAN stations with current data in the area that are less representative include Palm Springs, Blythe Airport and Yuma Arizona Airport. Representative upper air data for the same time period were obtained from the Tucson, Arizona upper air sounding site (WMO ID 72280). The WBAN surface station data was processed with WMO upper air data to produce the meteorological files used for emissions modeling (Atmospheric Dynamics, 2008). Potential air quality impacts from the Amended Project were therefore evaluated using this meteorological data year.

Winds

High winds are occasionally experienced in the Imperial Valley. Monthly average wind speeds in the region range from 6.6 mile per hour (mph) in October to 9.5 mph in July. Annually, winds average 7.8 mph. Winds in the valley are primarily from west to east throughout the year, but have a secondary southeast component in the fall. Solar insolation data suggests that 90 percent of possible sunshine occurs in the region. The cloudiest periods occur in winter while the sunniest periods are in the summer. Wind movements in the Project area are important to several engineering decisions on plant design including the distribution of air pollutant emissions from the Project. The wind distribution for both speed and direction components are graphically represented in wind roses. A wind rose for the years 2002 through 2006 combined, and separate quarterly wind roses are presented in Appendix E.1. In general, the winds have a predominantly west to southwesterly component with the average wind speed of 5.23 mph. There is also a significant percentage of calm winds (18.5 percent) when there is no measurable wind speed or wind direction.

Temperature

Temperatures in the Project area can be very hot during the summer months and cold during the winter months. Table 5.2-7 summarizes daily maximum and minimum temperatures, extreme high and low temperatures by month; the mean number of days the maximum temperature exceeds 90°F, the mean number of days the minimum temperature is less than 0°F per month, and the mean number of days the minimum temperature is less than 32°F and less than 0°F each month.

Table 5.2-7 Temperature Data for Brawley, California

Month	Monthly Temperatures			Extremes		Mean Number of Days			
						Maximum		Minimum	
	Daily Max	Daily Min	Mean	Highest Mean	Lowest Mean	90°F & Above	32°F & Below	32°F & Below	0°F & Below
Jan	70.4	39.2	54.8	76.5	50.6	0.0	0.0	5.2	0.0
Feb	74.7	42.7	58.7	81.0	54.7	0.3	0.0	1.2	0.0
Mar	79.5	46.9	63.2	88.4	58.1	2.9	0.0	0.1	0.0
Apr	86.1	52.1	69.1	93.8	61.7	10.8	0.0	0.0	0.0

Table 5.2-7 Temperature Data for Brawley, California

Month	Monthly Temperatures			Extremes		Mean Number of Days			
						Maximum		Minimum	
	Daily Max	Daily Min	Mean	Highest Mean	Lowest Mean	90°F & Above	32°F & Below	32°F & Below	0°F & Below
May	93.8	58.7	76.3	100.9	70.2	23.2	0.0	0.0	0.0
Jun	103.3	65.9	84.6	109.6	80.7	28.5	0.0	0.0	0.0
Jul	107.0	73.7	90.4	110.7	86.8	30.7	0.0	0.0	0.0
Aug	106.2	74.8	90.5	109.5	86.1	30.6	0.0	0.0	0.0
Sep	101.7	69.0	85.4	106.2	79.7	28.5	0.0	0.0	0.0
Oct	91.4	57.6	74.5	98.2	68..5	19.3	0.0	0.0	0.0
Nov	78.9	45.2	62.1	85.0	57.2	2.2	0.0	0.0	0.0
Dec	70.3	38.7	54.5	77.7	50.4	0.0	0.0	4.2	0.0
Annual	88.6	55.4	72.0	110.7	50.4	177.0	0.0	11.3	0.0
Source: WRCC, 2008.									

Precipitation

Average annual precipitation in the Project area, based on Brawley records from 1910 through 2007, is 2.65 inches, with approximately 92 percent of the precipitation occurring in the months between August and March. Table 5.2-8 summarizes mean, highest monthly and daily rainfall by month; mean number of days with rainfall of 0.10, 0.50, and 1.0 inches or more; and mean and one-day maximum snowfall.

Table 5.2-8 Precipitation Data for Brawley, California

Month	Rainfall						Snowfall inches (”)	
	Inches			Mean Number of Days				
	Mean	Highest Monthly	Highest Daily	0.10” or more	0.50” or more	1.0” or more	Mean	One-Day Max.
Jan	0.40	3.5	1.50	1	1	0	0	0
Feb	0.39	2.0	1.10	1	1	1	0	0
Mar	0.26	2.2	1.46	1	1	0	0	2
Apr	0.11	1.9	0.83	0	0	0	0	0
May	0.03	0.60	0.60	0	0	0	0	0
Jun	0.01	0.29	0.29	0	0	0	0	0
Jul	0.05	1.14	0.78	0	0	0	0	0
Aug	0.30	4.89	3.73	1	0	0	0	0

Table 5.2-8 Precipitation Data for Brawley, California

Month	Rainfall						Snowfall inches (")	
	Inches			Mean Number of Days				
	Mean	Highest Monthly	Highest Daily	0.10" or more	0.50" or more	1.0" or more	Mean	One-Day Max.
Sep	0.25	6.75	3.80	0	0	0	0	0
Oct	0.22	3.90	3.90	0	0	0	0	0
Nov	0.17	1.36	1.17	0	0	0	0	0
Dec	0.46	4.10	2.65	1	0	0	0	3.0
Annual	2.65	8.18	3.90	6	1	0	0	3.0

5.2.3.2 Ambient Air Quality Data

The Project site is located in the SSAB and is under the jurisdiction of the ICAPCD. NAAQS and CAAQS are shown in Table 5.2-9. The attainment status of the Project area with respect to the Federal and California air quality standards is summarized in Table 5.2-10 (CARB, 2008d).

Table 5.2-9 National and California Ambient Air Quality Standards

Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards[1] Concentration[3]	California Standards[1] Method[4]	Federal Standards[2] Primary[3,5]	Federal Standards[2] Secondary[3,6]	Federal Standards[2] Method[7]
Ozone (O_3)	1 Hour	0.09 ppm (180 $\mu g/m^3$)	Ultraviolet Photometry	—	Same as Primary Standard	Ultraviolet Photometry
	8 Hour	0.070 ppm (137 $\mu g/m^3$)		0.075 ppm (147 $\mu g/m^3$)		
Respirable Particulate Matter (PM10)	24 Hour	50 $\mu g/m^3$	Gravimetric or Beta Attenuation	150 $\mu g/m^3$	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	20 $\mu g/m^3$		—		
Fine Particulate Matter (PM2.5)	24 Hour	No Separate State Standard		35 $\mu g/m^3$	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	12 $\mu g/m^3$	Gravimetric or Beta Attenuation	15.0 $\mu g/m^3$		
Carbon Monoxide (CO)	8 Hour	9.0 ppm (10mg/m^3)	Non-Dispersive Infrared Photometry (NDIR)	9 ppm (10 mg/m^3)	None	Non-Dispersive Infrared Photometry (NDIR)
	1 Hour	20 ppm (23 mg/m^3)		35 ppm (40 mg/m^3)		
	8 Hour (Lake Tahoe)	6 ppm (7 mg/m^3)		—	—	—
Nitrogen Dioxide (NO_2)	Annual Arithmetic Mean	0.030 ppm (57 μg/m3)	Gas Phase Chemiluminescence	0.053 ppm (100 $\mu g/m^3$)	Same as Primary Standard	Gas Phase Chemiluminescence
	1 Hour	0.18 ppm (339 $\mu g/m^3$)		—		
Sulfur Dioxide (SO_2)	Annual Arithmetic Mean	—	Ultraviolet Fluorescence	0.030 ppm (80 $\mu g/m^3$)	—	Spectrophotometry (Pararosaniline Method)
	24 Hour	0.04 ppm (105 $\mu g/m^3$)		0.14 ppm (365 $\mu g/m^3$)	—	
	3 Hour	—		—	0.5 ppm (1300 $\mu g/m^3$)	
	1 Hour	0.25 ppm (655 $\mu g/m^3$)		—	—	—
Lead[8]	30 Day Average	1.5 $\mu g/m^3$	Atomic Absorption	—	—	—
	Calendar Quarter	—		1.5 $\mu g/m^3$	Same as Primary Standard	High Volume Sampler and Atomic Absorption
	Rolling 3-Month Average[9]	—		0.15 $\mu g/m^3$		
Visibility Reducing Particles	8 Hour	Extinction coefficient of 0.23 per kilometer — visibility of ten miles or more (0.07 — 30 miles or more for Lake Tahoe) 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 $\mu g/m^3$	Ion Chromatography			
Hydrogen Sulfide	1 Hour	0.03 ppm (42 $\mu g/m^3$)	Ultraviolet Fluorescence			
Vinyl Chloride[8]	24 Hour	0.01 ppm (26 $\mu g/m^3$)	Gas Chromatography			

See footnotes on next page …

For more information please call ARB-PIO at (916) 322-2990

California Air Resources Board (11/17/08)

Table 5.2-9 National and California Ambient Air Quality Standards (continued)

1. California standards for ozone, carbon monoxide (except Lake Tahoe), sulfur dioxide (1 and 24 hour), nitrogen dioxide, suspended particulate matter—PM10, PM2.5, and visibility reducing particles, are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in Section 70200 of Title 17 of the California Code of Regulations.

2. National standards (other than ozone, particulate matter, and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest eight hour concentration in a year, averaged over three years, is equal to or less than the standard. For PM10, the 24 hour standard is attained when the expected number of days per calender year with a 24-hour average concentration above 150 $\mu g/m^3$ is equal to or less than one. For PM2.5, the 24 hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. Contact U.S. EPA for further clarification and current federal policies.

3. Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

4. Any equivalent procedure which can be shown to the satisfaction of the ARB to give equivalent results at or near the level of the air quality standard may be used.

5. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

6. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

7. Reference method as described by the EPA. An “equivalent method” of measurement may be used but must have a “consistent relationship to the reference method” and must be approved by the EPA.

8. The ARB has identified lead and vinyl chloride as 'toxic air contaminants' with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

9. National lead standard, rolling 3-month average: final rule signed October 15, 2008.

Table 5.2-10 Summary of Attainment Status of the Project Area

Pollutant	Attainment Status	
	Federal Standards	California Standards
Ozone – 1 Hour	No longer applicable	Moderate non-attainment
Ozone – 8 Hour	Non-attainment	Non-attainment
CO	Unclassified / Attainment	Attainment
NO_2	Unclassified / Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Non-attainment	Non-attainment
PM2.5	Unclassifiable / Attainment	Unclassified
Lead Particulates	No Designation	Attainment
Reference: CARB, 2008a.		

The closest air quality monitoring stations to the Project site are Niland (7711 English Rd., Niland, CA 92257), Westmorland (570 Cook St., Westmorland, CA 92281), and Brawley (220 Main St., Brawley, CA 92227). All are operated by the ICAPCD. Table 5.2-11 summarizes the locations of these monitoring stations relative to the Project site, the pollutants monitored, and the approximate distance from the Project site.

Table 5.2-11 Air Quality Monitoring Stations Closest to the Project Site

Monitoring Site	Pollutants Measured at Monitoring Station						Approx Distance and Direction from Project Site	County
	O_3	NO_2	SO_2	CO	PM10	PM2.5		
Niland	X				X		5.6 miles northeast	Imperial
Westmorland	X				X		9 miles east	Imperial
Brawley	X				X	X	13 miles southeast	Imperial
El Centro		X		X	X		26 miles southeast	Imperial
Calexico			X				29 miles southeast	Imperial
Note: CEC generally requires the three closest monitoring stations to be identified. However, for this Project, the three closest stations do not monitor NO_2, SO_2 or CO, thus two additional sites are identified. Reference: CARB, 2008b.								

Tables 5.2-12 through 5.2-17 provide summaries of air quality data collected by the nearest monitoring stations for the pollutant of interest and the number of times that the NAAQS and the CAAQS were exceeded for each parameter for the years 2005 through 2007.

The Salton Sea area is non-attainment for the national eight-hour ozone standard, and moderate non-attainment and non-attainment for the California one-hour and eight-hour ozone standards, respectively. These attainment statuses are reflected in the ambient monitoring data presented in Table 5.2-12. The Amended Project will be a source of ozone precursor pollutant emissions.

Table 5.2-12 Ozone Data for Monitoring Stations near the Project Plant Site

Site	# Days >1-Hr CAAQS	Highest 1-Hr Observation (ppm)	# Days >8-hr NAAQS	Highest 8-Hr Observation (ppm)
Calendar Year 2007				
Niland	0	0.091	0	0.082
Westmorland	7	0.102	5	0.091
Brawley	0	0.082	0	0.069
Calendar Year 2006				
Niland	0	0.091	0	0.080
Westmorland	8	0.104	5	0.088
Brawley	0	0.063	0	0.049
Calendar Year 2005				
Niland	0	0.091	0	0.078
Westmorland	11	0.112	10	0.1000
Brawley	ND	ND	ND	ND
ND – Insufficient data to determine valid value, so value not reported on the CARB website.				
Reference: CARB, 2008c.				

Table 5.2-13 provides PM10 monitoring data for the region. The Project area is classified as non-attainment for the California 24-hour PM10 standard. The California standard was exceeded a maximum of 159 days at Brawley, a maximum of 127 days at Westmorland, and on a maximum of 83 days at Niland during the 2005 to 2007 period.

Table 5.2-13 PM10 Data for Monitoring Stations Near the Project Plant Site

Site	# Days > 24-Hr NAAQS	# Days > 24-Hr CAAQS	Annual State Average (μg/m^3)	Highest State 24-Hr Average (μg/m^3)
Calendar Year 2007				
Niland	3.5	82.8	39.6	160
Westmorland	14	126.6	48.8	222
Brawley	13	158.6	55.8	296
Calendar Year 2006				
Niland	0	30.5	34.7	113
Westmorland	13.1	ND	ND	177

Table 5.2-13 PM10 Data for Monitoring Stations Near the Project Plant Site

Site	# Days > 24-Hr NAAQS	# Days > 24-Hr CAAQS	Annual State Average (µg/m^3)	Highest State 24-Hr Average (µg/m^3)
Brawley	0	100.2	44.6	123
Calendar Year 2005				
Niland	0	32	31.1	75
Westmorland	0	11.5	31.4	57
Brawley	0	29.4	35.2	71
ND – Insufficient data to determine valid value so value not reported on the CARB website.				
Reference: CARB, 2008c.				

Monitoring data for PM2.5 presented in Table 5.2-14 shows that the NAAQS was exceeded on three days at Calexico – Ethel Street during the 2005 to 2007 period, which is consistent with the national unclassified/attainment and California unclassified status for this pollutant.

Table 5.2-14 PM2.5 Data for Monitoring Stations Near the Project Plant Site

Site	# Days > 24-Hr NAAQS	National Annual Average (µg/m^3)	National Highest 24-Hr Average (µg/m^3)
Calendar Year 2007			
Brawley	0	ND	19.5
El Centro	0	8.5	30.5
Calexico – Ethel Street	ND	ND	52.7
Calendar Year 2006			
Brawley	0	ND	30.4
El Centro	0	8.8	33.8
Calexico – Ethel Street	3.2	12.5	68.8
Calendar Year 2005			
Brawley	0	ND	37.8
El Centro	0	9.4	57.9
Calexico – Ethel Street	ND	ND	67.6
[1]ND – Insufficient data to determine valid value, so value not reported by CARB.			
Reference: CARB, 2008c.			

CO, NO_2 and SO_2 data presented in Tables 5.2-15, 5.2-16 and 5.2-17 are below the applicable NAAQS and CAAQS and are consistent with the attainment status for these pollutants.

Table 5.2-15 CO Data for Monitoring Stations Near the Project Plant Site

Site	Highest 8-Hr Observation, (ppm)	# Days > 1- or 8-Hr NAAQS	# Days > 1- or 8-Hr CAAQS
Calendar Year 2007			
El Centro	1.67	0	0
Calexico – Ethel Street	7.53	0	0
Calexico – Central Street	4.50	0	0
Calendar Year 2006			
El Centro	2.59	0	0
Calexico – Ethel Street	9.76	1	0
Calexico – Central Street	5.80	0	0
Calendar Year 2005			
El Centro	2.23	0	0
Calexico – Ethel Street	8.98	0	0
Calexico – Central Street	7.76	0	0
Reference: CARB, 2008c.			

Table 5.2-16 NO_2 Data for Monitoring Stations Near the Project Plant Site

Site	Highest 1-Hr Observation (ppm)	# Days >1-Hr CAAQS	Annual Average (ppm)
Calendar Year 2007			
El Centro	0.071	0	0.011
Calexico – Ethel Street	0.107	0	0.014
Calexico – Central Street	0.112	0	0.010
Calendar Year 2006			
El Centro	0.066	0	0.011
Calexico – Ethel Street	0.101	0	0.014
Calexico – Central Street	0.094	0	0.012
Calendar Year 2005			
El Centro	0.065	0	0.011
Calexico – Ethel Street	0.131	0	0.015
Calexico – Central Street	0.114	0	0.012
Reference: CARB, 2008c.			

Table 5.2-17 SO_2 Data for Monitoring Stations Near the Project Plant Site

Site	Highest 1-Hr Observation (ppm)	# Days >1-Hr CAAQS	Annual Average (ppm)
Calendar Year 2007			
Calexico – Ethel Street	0.004	0	0.001
Calendar Year 2006			
Calexico – Ethel Street	0.041	0	0.001
Calendar Year 2005			
Calexico – Ethel Street	0.002	0	0.000
Reference: CARB, 2008c.			

5.2.4 Control Technology Assessment

The preliminary control technology assessment (BACT Analysis) for the Amended Project is provided in this section. The assessment presented herein is a preliminary determination based on the most current data readily available through on-line databases. The following sources were reviewed for their applicability to the BACT provisions:

- Cooling tower;
- NCG steam; and
- Emergency generator and fire water pump engines.

BACT is defined in ICAPCD Rule 101 as the more stringent of:

1. The most effective emission control device, emission limit, or technique which has been achieved in practice for such class or category of source unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitations are not achievable.

2. Any other alternative emission control device, emission control technique, basic equipment, fuel, or process determined to be technologically feasible and cost-effective by the Air Pollution Control Officer. Cost-effectiveness analyses shall be performed in accordance with methodology and criteria specified in the Best Available Control Technology Guideline for the South Coast Air Quality Management District, or an alternative methodology and criteria acceptable to the Air Pollution Control Officer.

3. Under no circumstances shall BACT be determined to be less stringent than the emission control required by any applicable provision of laws or regulations of the District, State and Federal government, or the most stringent emissions limitation which is contained in the implementation plan of any State, unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitations are not technologically achievable. In no event shall the application of

BACT result in the emissions of any pollutant which exceeds the emissions allowed by any applicable NSPS (40 CFR, part 60) or NESHAP (40 CFR, part 61)".

EPA guidance for a "top-down" BACT analysis requires reviewing the possible control options starting with the best control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because it/they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis. The steps required for a "top-down" BACT review are:

1. Identify available control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining technologies;
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts); and
5. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons).

Publicly available information on emission control technologies was reviewed for step one of this analysis. Control technologies employed at various geothermal power plants in California, including the Geysers, Bottle Rock, Coso and Salton Sea power plants were reviewed. The type of control technology employed at a geothermal power plant and its efficiency also depends upon the type of geothermal power plant. The control technologies vary depending upon whether the power plant is dry steam (e.g., Geysers), flash steam (e.g., Coso or Salton Sea), or a binary plant (e.g., ORMAT).

Since there are not many geothermal power plants operating in California, control technologies employed for processes with similar exhaust streams, or exhaust streams with similar pollutants in other industries were also reviewed. Some of the processes reviewed include the following:

- Sulfur Recovery Unit (SRU) in refineries for H_2S emission abatement from sour gas;
- Air/steam stripping in refineries for H_2S and NH_3 emission abatement from sour water;
- Wastewater treatment and sanitary sewer units for H_2S and NH_3 emission abatement;
- Spray booths for ROC emission;
- Air stripper for ROC emission abatement; and
- Waste incinerators and coal-fired boiler and power plants for mercury (Hg) abatement.

Databases reviewed include the South Coast Air Quality Management District's BACT/lowest achievable emission rate (LAER) Guidelines, EPA's reasonably available control technology/BACT/LAER Clearinghouse, Bay Area Air Quality Management District (BAAQMD's) BACT database, and recent or pending projects in the CEC database.

A source-specific and pollutant-specific BACT determination is provided in the following subsections. Each BACT determination is made through the five-step process to identify available control technologies, eliminate technically infeasible options, rank and evaluate remaining technologies, and BACT selection.

5.2.4.1 BACT Determination for Evaporative Mechanical Draft Cooling Tower

Mechanical draft evaporative cooling towers will be used for the Amended Project to provide cooling water to condense the spent steam from the back end of the steam turbine. Condensed steam will furnish the majority of the make-up water to the cooling towers. During certain times of the year, make-up water in the form of fresh water from the IID system will be required. Condensed steam contains impurities such as dissolved gases and solids which may be emitted at the cooling tower as off-gases and drift particles, respectively. The following sub-sections present the BACT determinations for cooling tower emissions.

BACT for PM10

The technologies available for control of PM10 from cooling towers include:

- Use of alternative cooling technologies such as “dry” cooling.
- High-efficiency drift eliminator for wet cooling tower.

The dry cooling method is not economically feasible for this Project. Furthermore, many other projects have demonstrated that additional criteria pollutant emissions would be generated in order to make up the power lost due to the additional electrical loads that occur in a dry-cooled plant.

The Project will install three 5-cell cooling towers. Based on the review of some of the most recent CEC-approved projects (e.g., Victorville II Hybrid Power Plant) or the projects pending CEC approval (e.g., Palmdale Hybrid Power Plant, Beacon Solar LLC facility), the current LAER for PM10 emissions from cooling tower was found to be the use of high efficiency drift eliminators with a drift rate of 0.0005 percent of the water circulation rate. Because LAER is more stringent than BACT, this technology and emission rate satisfies BACT. Therefore, BACT for PM10 from evaporative cooling towers is the use of high efficiency drift eliminators. No other control technology has been identified that could reduce the emissions of PM10 from an evaporative cooling tower beyond the levels that can be achieved with state-of-the-art drift eliminators.

Use of the drift eliminators with a drift rate of 0.0005 percent constitute BACT for PM10 emissions from the proposed evaporative cooling towers.

BACT for H_2S

The type of H_2S abatement system employed depends on the amount of H_2S present in the condensate, which in turn depends on the type of geothermal power plant and the type of condenser employed. The most commonly used technologies for the abatement of H_2S dissolved in a liquid medium can be segregated into three categories:

- Biological oxidation,
- Chemical oxidation, and

- Air or steam stripping with downstream treatment.

Biological Oxidation. Biological oxidation for H_2S abatement in condensate stream is being utilized at the Applicant's Units 1, 2, 3, 4, and 5. With this technique, one of the top cells of the cooling tower is used as a packed bed bioreactor. Some of the advantages of biological oxidation system include reduction in the growth of micro-organisms in the cooling tower and H_2S abatement efficiency of up to 90 percent. Some of the disadvantages of this technology include the following:

1. As the bioreactor is open to the atmosphere, uncontrolled H_2S emissions can occur due to off-gassing.

2. Biological systems are vulnerable to fluctuations in operational parameters such as liquid temperature, pH, dissolved oxygen concentration, seasonal fluctuations in ambient temperature, and availability of light and nutrients for microbial growth. These fluctuations will ultimately affect the abatement efficiency.

3. Biological oxidation produces biomass resulting in operational problems due to plugging of the cooling tower.

Chemical Oxidation. Several chemical oxidation techniques are available for removal of H_2S from condensate. Most of these techniques use iron or iron salts as oxidizing agents or catalysts and oxidize H_2S to sulfur or iron sulfides. Iron catalyst was used for chemical oxidation of H_2S to sulfur in five units at the Geysers power plants until December 1978 (CEC, 1980). A combination of iron catalyst and hydrogen peroxide has been used at the five units at the Geysers power plants since January 1979 to oxidize H_2S to sulfur (CEC, 1980).

BAAQMD has specified the injection of ferrous chloride to the wastewater as BACT for H_2S abatement in sewage treatment plants. Ferrous chloride reacts with H_2S to form iron sulfide precipitate.

The Applicant has tested a chemical oxidation system referred to as "ChemOx". The ChemOx system will use a combination of chemicals including trichloroisocyanuric acid (trade name: Towerbrom) and sodium hypochlorite to oxidize H_2S into water soluble sulfates which are discharged from the cooling tower with blowdown. This system has been tested by the applicant at the existing Salton Sea geothermal facility and has demonstrated an abatement efficiency of 95 percent. The advantages of the ChemOx system over commonly used biological and other chemical oxidation systems include the following:

1. The ChemOx system will eliminate the uncertainties associated with the fluctuations of operational parameters in a biological oxidation system. It will also eliminate the operational problems associated with the formation and management of biomass.

2. The commonly available chemical oxidation systems produce sulfur or iron sulfide sludge in the cooling tower. This causes plugging and corrosion of a cooling tower resulting in operational problems and increased downtime for maintenance. The ChemOx system eliminates these problems by forming water soluble sodium sulfate.

Air/Steam Stripping. Air/steam stripping has been widely used in refineries to treat sour water for H_2S and NH_3. However, as discussed below, it cannot be concluded that this technique is BACT for the Project. An air stripper can be used upstream of the cooling towers to treat the sour condensate in the proposed Project. H_2S-laden offgas from the stripper would be vented to the H_2S abatement system for the NCG stream. Some of the advantages and limitations of air stripping to treat the H_2S in condensate are discussed below. Advantages of air stripping include:

1. An H_2S removal efficiency of up to 99 percent can be achieved (EPA, 2008a);

2. The system does not require use of expensive chemicals as required for chemical oxidation processes;

3. The system is more reliable and efficient than biological oxidation processes;

4. Air stripping can also remove NH_3 and organic compounds dissolved in the condensate; and

5. No hazardous byproducts or waste are generated that would require costly disposal and regulatory compliance.

Limitations of air stripping include:

1. The sour water in a geothermal power plant contains less H_2S than the sour water in refineries (where sour water stripping is a common practice). Lower H_2S concentrations affect mass transfer equilibrium, and make the process more expensive and less efficient (CEC, 1980). Higher air flow rates may be needed to achieve the required removal efficiency, which results in increases in power and design capacity of downstream abatement systems.

2. Designing strippers for low-H_2S content liquids is difficult, and the strippers will tend to be bulky and expensive (CEC, 1980).

3. The efficiency of the system decreases due to the presence of NH_3 at higher pH. Careful pH control is required to maintain a required H_2S removal efficiency.

4. Additional chemical handling and storage may be required.

5. The condensate is used as cooling tower make-up water. Air stripping will cause vaporization of the condensate (i.e., humidifying the airstream), thus reducing the quantity of water available as make-up to the cooling tower. Additional water from other sources will be required to fulfill the make-up water requirements.

6. If the acid gas from the stripper would require downstream H_2S abatement, the capacity, fuel and chemical requirements of the downstream abatement systems will increase; e.g., if a thermal incinerator and scrubber combination is employed to control H_2S emissions from gaseous streams, then venting the acid gas from stripper will not only increase the necessary capacity and fuel requirements of the thermal incinerator, but also increase criteria pollutant emissions from fuel combustion. Similarly, the size of the caustic scrubber, and chemical and water requirements will increase to control the increased gas flow rate and SO_2 emissions. Capital and operating costs for the downstream abatement system would increase as well.

BAAQMD BACT determinations suggest that an H_2S control efficiency of 95 percent from a sour water stripper in a refinery is possible.

Based on the BACT database review conducted for this Control Technology Assessment, no evidence was found that sour water stripping has been used for H_2S abatement for geothermal condensate streams. Therefore, it is not possible based on a literature review to assess whether or not a sour water stripper is feasible for this application, and if it were feasible, what level of control would be achieved. Further, with no operating units to evaluate, it is not possible to evaluate if such a stripper would have adverse environmental consequences that outweigh whatever benefit might be achieved. As noted, downstream treatment of the acid gas would require fuel combustion, with associated emissions, and reduce water available for cooling tower makeup, thus placing a greater demand on water resources. Therefore, because air stripping has not been achieved in practice, and a realistic assessment of the expected control efficiency cannot be made, air/steam stripping has been eliminated from further consideration as potential BACT for H_2S abatement from condensate stream in the proposed Project.

Based on the review of various control technologies, the applicant proposes the ChemOx abatement system with a control efficiency of 95 percent as BACT for H_2S emissions control from the Project's cooling towers.

5.2.4.2 BACT Determination for Noncondensable Gas Streams

The NCG stream contains several constituents for which a control technology assessment is appropriate, including H_2S, ROC and Hg.

BACT Determination for H_2S

The technologies available for the abatement of H_2S in the NCG streams can be segregated into the following categories:

- Physical processes like carbon adsorption, scrubbing or air stripping;
- Biological oxidation,
- Chemical oxidation, and
- Thermal oxidation or incineration.

Carbon Adsorption and Scrubbing

Some of the limitations of physical processes like carbon adsorption and scrubbing for abatement of H_2S in NCG include:

1. H_2S removal efficiency will be reduced significantly due to the presence water and of other pollutants like ROCs, Hg and arsenic in the NCG. To achieve a desirable efficiency more adsorbing media, frequent regeneration, and more units would be required. This will also increase the operating cost.

2. Regeneration of adsorbing media or scrubbing solution will result in secondary pollutants and associated environmental impacts at some other location.

Due to the above limitations, this technology is not considered feasible for the proposed Project and is therefore eliminated from further consideration.

Biological Oxidation

The biological oxidation technique for H_2S abatement in NCG stream is being utilized at Salton Sea Units 1, 2, 3, and 4. With this technique, the NCG stream is passed through a biofilter where microbial action oxidizes H_2S to sulfur or sulfate compounds. Some of the advantages of this system include H_2S abatement efficiency of up to 95 percent, low capital cost, and low operating cost because the technology does not require chemical additives or material handling. Some of the limitations of this technology include the following:

1. Biological systems are vulnerable to fluctuations in operational parameters such as temperature, pH, light, dissolved oxygen concentration, and availability of nutrients for microbial growth. These fluctuations will ultimately affect the abatement efficiency.

2. The end products of biological oxidation are either sulfur or sulfate. Reduction in pH of the media due to sulfate formation or sulfur deposition on the media can reduce the efficiency of the process (Syed et. al., 2006).

3. The process needs very close and frequent monitoring, operational flexibility, and frequent filter cleaning to ensure proper operation and high abatement efficiency.

4. Biomass produced might be contaminated with Hg making it a hazardous waste.

5. This system does not control other pollutants such as As and Hg that may be present in the NCG.

6. Biological oxidation systems may have lesser control efficiency than chemical oxidation systems and the efficiency is dependent upon numerous operational parameters.

Oxidation

Several types of oxidation techniques are available for removal of H_2S from NCG streams. The concentration of H_2S in the NCG will be comparable to the concentration of H_2S in the tail gas from the SRU and the Tail-Gas Treatment Unit (TGTU) at a refinery. Hence, BACT guidelines and determinations for refinery SRUs were reviewed to determine BACT for the proposed Project.

Oxidation technologies use different oxidizing agents or catalysts to oxidize H_2S to elemental sulfur. Some of the commonly available oxidation technologies to control H_2S in gaseous stream include the Stretford process, the LO-CAT II process and the Claus process. The Stretford process has been employed to treat the offgases from the condenser at Geysers and Bottle Rock geothermal power plants. LO-CAT II process is being used in several units at the Coso Geothermal Power Plant and was also accepted as BACT for the original project. The Claus process and its variations are used to treat the sour gas at refineries and produce elemental sulfur. Some of the advantages and disadvantages of these processes are discussed below.

One constituent of the brine processed in the Amended Project is Hg. Abatement systems which produce elemental sulfur from H_2S are expected to produce sulfur contaminated with Hg. Sulfur produced in such a manner may have to be disposed off as a hazardous waste resulting in increased regulatory requirements, material handling, and disposal cost. This limitation applies to any of the technologies discussed in this section which would produce sulfur as a byproduct.

Stretford Process

The main advantage of this process is its high abatement efficiency. The Stretford process can achieve an abatement efficiency of more than 99 percent. The Stretford process is expected to be quite reliable. The process has the following limitations:

1. When the power plant goes off-line, steam is not available for heating the sulfur lines in the Stretford unit. Reheating of sulfur takes approximately three hours. The Stretford unit must be shutdown or alternate methods of sulfur disposal must be arranged while the lines reheat (CEC, 1980).

2. The process is costly and complex in nature as it requires several expensive chemicals and catalyst and frequent monitoring (US Patents 4285917).

3. The Stretford process has sulfur as a byproduct, which with this particular situation would be expected to be contaminated with Hg, thus making it a hazardous waste. The contaminated sulfur cannot be sold to generate revenue and would increase the regulatory requirements, cost, and environmental impacts associated with its disposal.

4. This process would not control pollutants such as ROCs or benzene, and additional treatment units will be required to remove these pollutants. This will also increase the footprint and capital and operating cost of the Amended Project.

LO-CAT II Process

The LO-CAT II process can achieve removal efficiencies exceeding 99 percent. It uses less expensive chemicals and catalyst than the Stretford process. The LO-CAT II process has the following limitations which are very similar to the Stretford process:

1. The LO-CAT II system does not operate at low loads or during plant startup and shutdown.

2. The LO-CAT II system would produce approximately two tons per day of sulfur potentially contaminated with Hg. Hg-contaminated sulfur would require disposal as hazardous waste. The LO-CAT process would increase the regulatory requirements, cost, and environmental impacts associated with the disposal of sulfur contaminated with Hg.

3. This process would not control pollutants such as ROC or benzene, and additional treatment units will be required to remove these pollutants. The original project had proposed carbon adsorption for this purpose. Benzene-saturated carbon would have to be managed as hazardous waste and/or regenerated resulting in emissions from transportations and regeneration. This would increase the footprint and capital and operating costs of the Amended Project.

Claus Process

The Claus process and its variations are being employed at refineries to recover sulfur from acid gas. These process units, known as SRU, can achieve efficiencies exceeding 99 percent. H_2S introduced into a

Claus unit is converted in two steps. In a thermal step, the H_2S is partially oxidized with air in a high-temperature reaction furnace. Sulfur is formed, but some H_2S remains unreacted, and some SO_2 is made. In a catalytic step, the remaining H_2S is reacted with the SO_2 at lower temperatures over a catalyst to produce additional sulfur. A catalyst is needed in the second step to help the components react with reasonable speed. The reaction does not go to completion even with the best catalyst. For this reason, two or three stages are often used, with sulfur being removed between the stages. A small amount of H_2S will remain in the tail gas which is usually dealt with in a TGTU. There are a variety of technologies available for use in TGTUs. The advantages and disadvantages of SRU are similar to Stretford and LO-CAT II process.

Thermal Oxidation

Thermal oxidation or incineration is another technology available to control H_2S emissions from the NCG stream. Thermal oxidizers include regenerative thermal oxidizers, RTOs, direct oxidation, and catalytic oxidation. RTOs can achieve control efficiency of 98 percent or more. RTOs installed in process applications with lower flow rates or for ROC concentrations above 10 percent of the lower explosive limit can achieve a destruction efficiency of 99 percent.

Direct oxidation is not preferred if heat recovery is desirable or available, as fuel costs can be prohibitive. Catalytic oxidation is usually not used when sulfur compounds are present, as the sulfur will contaminate the catalyst. Direct oxidation and catalytic oxidation have been eliminated from further consideration.

A regenerative thermal oxidizer was installed at Salton Sea Units 1 and 2 for benzene control. The internal temperature of the unit was, at times, below the dew point for sulfuric acid mist, causing corrosion and eventually mechanical failure. Due to past experiences with corrosion, regenerative thermal oxidizers are not considered feasible for the Amended Project and are therefore eliminated from further consideration as BACT.

RTOs use a supplemental fuel source to maintain the combustion chamber temperature at a constant value. This inhibits the formation of sulfuric acid mists mitigating the corrosion problem encountered by the Applicant with the regenerative thermal oxidizers. The applicant has installed RTOs on Salton Sea Units 1 through 4 and proposes this technology for the Amended Project.

Some of the significant advantages of RTOs over the chemical oxidation technologies include:

1. Unlike LO-CAT II, RTOs can operate at variable loads.

2. RTOs do not require expensive chemicals for H_2S removal. This also reduces the material handling and regeneration requirements.

3. The chemical oxidation technologies discussed above can only remove H_2S from the NCG stream. RTOs can simultaneously remove H_2S, HAPs such as benzene, toluene, xylenes and ethylbenzene, along with other ROCs.

4. Unlike chemical oxidation systems, RTOs would not form an Hg contaminated sulfur byproduct.

5. One constituent of NCG is methane, a GHG, with approximately 21 times higher global warming potential than CO_2 (EPA, 2002). Chemical oxidation systems do not provide any control for

methane and it would be vented to the atmosphere untreated. RTOs will oxidize methane to CO_2, which has a lower global warming potential.

Unlike chemical oxidation systems that control only H_2S, RTOs can control H_2S, ROCs, HAPs that are ROCs, and methane emissions simultaneously. Separate units are not required to control these pollutants, thus reducing the capital and operating cost and the footprint of the proposed Project. The disadvantages of RTOs include:

1. The heat content of the NCG is insufficient to sustain the combustion process. Supplemental fuel (e.g., propane) is required to provide sufficient heat energy for thermal oxidation.

2. Because SO_2 formed during thermal oxidation needs to be removed, an additional control unit downstream of the RTOs, such as a caustic scrubber is required.

Chemical oxidation systems may have a higher control efficiency for H_2S, but they will not remove benzene from NCG. Since benzene is a HAP that could potentially be subject to a T-BACT requirement under ICAPCD Rule 216, a technology that provides higher benzene control is preferred over a technology that provides higher H_2S control.

In conclusion, based on the review of BACT determinations for similar processes and the advantages and limitations of various technologies, the applicant recommends a RTO with a total control efficiency of 95 percent as BACT for H_2S emissions control for the proposed Project. As discussed in the next section, the use of a RTO also provides the most suitable BACT alternative for ROCs.

BACT Determination for ROC

BACT is required to control emissions of ROC from the NCG streams before they are vented to the atmosphere. Commonly available technologies for ROC emissions control include:

- Carbon Adsorption
- Condensation
- Thermal Oxidation

Carbon Adsorption

Typical emission control efficiencies for ROC of 95 to 98 percent can be achieved by carbon adsorption systems. The adsorption systems can be of regenerable or non-regenerable type. In regenerable adsorption system, adsorbent regeneration is achieved by vacuum removal of the adsorbed ROCs or by steam heating of the adsorbent in order to drive off the ROC (LADCO, 2005). Thus, in regenerable adsorption systems, ROC emissions and associated environmental and health impacts could occur, but at a different location. If the adsorbent is not regenerated, it would have to be disposed off as a hazardous waste, increasing the regulatory requirements and material handling cost. Hazardous wastes with volatile constituents have to be transported to a treatment facility and incinerated prior to disposal. The transportation and incineration would both result in indirect emissions. Thus, whichever method of carbon regeneration is practiced, it would result in emissions and environmental impacts at a different location, if not at the Project site.

Condensation

In the condensation process, ROCs are cooled below their dew point and then condensed and recovered as a liquid. Although emission control efficiencies in excess of 95 percent can be achieved by condensation systems (LADCO, 2005), most of the liquid produced will consist of benzene which would have to be managed as a hazardous waste, thus increasing the regulatory requirements, material handling and disposal cost. Another limitation of this technology is the high temperature of NCG stream exiting the condenser. Due to the high temperature of NCGs, the system will require very large heat exchangers and coolant supply, which results in high energy costs, to condense the ROCs. The increased heat load could require additional cooling water from a tightly controlled supply in order to manage a larger cooling tower, increased blowdown, and increased drift.

Thermal Oxidation

Incineration or thermal oxidation is a widely used technology to control ROC emissions. It can achieve a ROC control efficiency of up to 98 percent. This technology is suitable for the Amended Project because it will control ROC emissions, and in addition control other pollutants including H_2S, CH_4, and specific HAPs (such as benzene) that are present in the NCG stream.

Based on the review of BACT determinations for similar processes and the advantages and limitations of various technologies, the applicant recommends a RTO with a destruction efficiency of 95 percent as BACT for ROC emissions control for the Amended Project.

5.2.4.3 BACT Determination for Emergency Diesel Generator and Fire Water Pump Engines

The Amended Project will include one 1.5 MW emergency diesel generator and one 1.0 MW emergency diesel generator per power block, and one diesel fire water pump rated at approximately 200 Hp for the Project. These emergency diesel engines will each operate for a maximum of 20 hours per year for maintenance and testing.

<u>BACT for NOx, CO and ROC</u>

The technologies employed for NOx, ROC and CO emissions control for internal combustion engines are listed below in descending order of effectiveness:

- Catalytic converter
- Oxidation catalyst
- California ATCM-compliant engine
- NSPS-compliant engine

Catalytic converters and oxidation catalysts have been proposed and used on a limited number of diesel engines in California; however, neither has been used on emergency engine installations due to the high cost and limited environmental benefit (due to the low number of hours of operation). Catalytic converters and oxidation catalysts are, therefore, determined to be infeasible for this application.

Title 17, CCR Section 93115, the California ATCM for Stationary CI Engines, provides standards for new stationary emergency standby diesel-fueled engines. The California emission standards specified in 13 CCR Section 2423 and the PM emission limits specified in 17 CCR § 93115 are at least as stringent as the requirements for a NSPS-compliant engine. NSPS, 40 CFR 60 Subpart IIII, was promulgated July 11, 2006 (71 Federal Register [FR] 39154) by EPA for stationary diesel engines. Therefore, compliance with the California emission standards and limits constitutes BACT for the emergency diesel generator and fire water pump engines.

The emergency diesel generator engines will meet the California Tier 4 limit of 0.67 grams per kilowatt-hour (g/kW-hr) of NOx and 0.4 g/kW-hr of NMHC for 2011 through 2014 model year diesel engines rated above 560 kW. The fire water pump engine will meet the California Tier 4 limit of 0.4 g/kW-hr for NOx and 0.19 g/kW-hr for hydrocarbon emissions for 2011 through 2014 model year diesel engines rated between 175 and 750 Hp. Use of engines that comply with these emission limits, plus an enforceable operating restriction of 50 hours per year for maintenance and testing for the fire water pump engine and 20 hours per year for each of the generator engines constitutes BACT for NOx emissions for both the emergency generator and the fire water pump engines.

The emergency diesel generator engines will meet the California Tier 4 limit of 3.5 g/kW-hr of CO for 2011 through 2014 model year diesel engines rated above 560 kW. The fire water pump engine will meet the California Tier 4 limit of 3.5 g/kW-hr for CO emissions for 2011 through 2014 model year diesel engines rated between 175 and 750 Hp. Use of engines that comply with these emission limits, plus an enforceable operating restriction of 50 hours per year for maintenance and testing for the fire water pump engine, and 20 hours per year for each of the generator engines constitutes BACT for CO emissions for both the emergency generator and the fire water pump engines.

BACT for PM10

The technologies employed for PM10/PM2.5 emissions control for CI engines are listed below in descending order of effectiveness:

- Diesel particulate trap
- California ATCM-compliant engine
- NSPS-compliant engine

Diesel particulate traps have been proposed and used on a limited number of diesel engines in California; however, they have not been used on emergency engine installations due to the high cost and limited environmental benefit (due to the low number of hours of operation). Diesel particulate traps are therefore determined to be infeasible for this application.

An ATCM-compliant engine is recommended as BACT for this application. The California emission limit for emergency engines with 31 to 50 hours per year allowed for maintenance and testing is 0.07 grams per brake horsepower-hour (g/Hp-hr) for engines above 560 kW and 0.015 g/Hp-hr for engines rated between 175 and 750 Hp. Therefore, compliance with an emission limit of 0.015 g/Hp-hr plus an enforceable operating restriction of 50 hours per year for maintenance and testing for the fire water pump engine and compliance with an emission limit of 0.07 g/Hp-hr plus an enforceable operating restriction of 20 hours per year for each of the generator engines constitutes BACT for PM10/PM2.5 emissions for these engines.

<u>BACT for SO_2</u>

Only ultra-low sulfur diesel fuel (15 ppmw) will be burned in the emergency generator and fire water pump engines. No add-on SO_2 controls are available for these sources. Therefore, use of ultra-low sulfur fuel constitutes BACT for SO_2 emissions from these units.

5.2.4.4 Summary of BACT Determinations

A summary of the BACT determinations for the Amended Project, based on the above evaluation, are provided in Table 5.2-18.

Table 5.2-18 Summary of BACT for the Amended Project

Source	NOx	SO_2	CO	ROC	PM10	H_2S
Cooling Tower	NA	NA	NA	NA	0.0005% drift eliminator	ChemOx with 95% removal efficiency
NCG stream	NA	Caustic Scrubber	NA	RTO with 95% efficiency	NA	RTO with 95% efficiency
1.5 MW Emergency diesel generator engine	0.67 g/kW-hr	15 ppm fuel S	3.5 g/kW-hr	0.4 g/kW-hr	0.07 g/Hp-hr	NA
1.0 MW Emergency diesel generator engine	0.67 g/kW-hr	15 ppm fuel S	3.5 g/kW-hr	0.4 g/kW-hr	0.07 g/Hp-hr	NA
200 Hp Emergency fire water pump engine	0.4 g/kW-hr	15 ppm fuel S	3.5 g/kW-hr	0.19 g/kW-hr	0.015 g/Hp-hr	NA
NA = Not applicable						

5.2.5 Environmental Impacts

5.2.5.1 Criteria Pollutant Emissions

Within the context of this emission calculation discussion, the term “power block” is used to mean the high pressure (HP) separator, Production Test Unit (PTU) and rock muffler of the Resource Production Facility (RPF), and the steam turbine, condenser and RTO and associated scrubber of the Power Generating Facility (PGF). As such, the Amended Project has three “power blocks”. The reason behind this aggregation of units from the RPF and PGF is to simplify the explanation of emissions during startup, shutdown and commissioning of the Project, as these operations have emissions from devices in both the RPF and PGF.

Emissions from construction, commissioning, startup, shutdown and normal operations of the Amended Project are summarized in this section. Detailed emission calculations are provided in Appendix E.3.

Construction Emissions

During the construction of the Amended Project, there will be emissions similar to those associated with any large industrial construction project. Onsite emissions will arise primarily from heavy-duty vehicle and equipment use. Onsite fugitive dust emissions will also be generated during site preparation and construction. Offsite emissions will occur from construction worker vehicles and material delivery trucks. The construction-related emissions are transient in nature that may cause some unavoidable but minor localized short-term impacts.

The Amended Project will include construction of the three power blocks and a short (~500 foot) water supply pipeline. There will be substantial earthwork on the plant site including the construction of three brine ponds, a storm water retention basin and a perimeter berm for flood protection, and civil site work including soil stabilization and foundation support. In addition, the Amended Project will construct nine geothermal production wells on three well pads, nine brine injection wells on three well pads, and four plant injection wells on two well pads. Well drilling will require the construction of six temporary mud sumps.

Construction of the three power blocks, including the required earthwork will require approximately 46 months (see Section 2.0, Project Description, Figure 2-14). Construction of production and injection wells is expected to take approximately 34 months. Construction of Project elements will occur concurrently.

Table 5.2-19 summarizes maximum daily construction emissions by phase of construction and Table 5.2-20 summarizes maximum annual construction emissions by phase of construction of the Amended Project. Details of the construction emission calculations are contained in Appendix E.3.

Table 5.2-19 Maximum Daily Construction Emissions

Phase of Construction	NOx lbs/day	ROC lbs/day	CO lbs/day	SO_2 lbs/day	PM10 lbs/day	PM2.5 lbs/day
Power block	183.29	26.81	239.89	0.23	138.81	35.83
Well construction – onsite	180.80	105.27	917.19	1.74	48.81	29.16
Well construction – offsite	180.80	105.27	917.19	1.74	48.81	29.16
Earthwork – onsite	107.73	12.18	39.80	0.11	52.38	14.70
Earthwork – offsite	129.88	14.12	80.03	0.15	79.07	21.19
The emissions in this table reflect the peak operating day for each phase of construction. The peak day for each phase will not occur on the simultaneously, thus the values should not be totaled.						

Table 5.2-20 Maximum Annual Construction Emissions

Phase of Construction	NOx Tpy	ROC Tpy	CO Tpy	SO_2 Tpy	PM10 Tpy	PM2.5 Tpy
Power block	21.66	3.31	30.84	0.03	17.00	4.47
Well construction – onsite	29.24	17.05	148.57	0.28	7.15	4.56
Well construction – offsite	29.24	17.05	148.57	0.28	7.15	4.56
Earthwork – onsite	7.13	0.80	2.59	0.01	3.85	1.05
Earthwork – offsite	11.84	1.29	7.18	0.01	7.12	1.91
The emissions reported in this table reflect the peak operating year for each phase of construction. The peak year for each phase will not occur on the simultaneously, thus the values should not be totaled.						

Commissioning Emissions

Emissions from commissioning activities are attributed to the air contaminants present in the NCG that are released from the brine with the steam phase in the HP separator. The Applicant has detailed information derived from existing operating plants that demonstrate the ratio of NCG to brine, NCG to steam, and the composition of the NCG. This information is used in conjunction with steam flow rates to estimate emissions. Uncontrolled emissions are expected during specific phases of commissioning and are emitted through either the PTU or rock muffler, as described below. Other phases of commissioning will involve venting the NCG through the RTO for emissions control.

Project commissioning will take place in three phases, with each power block commissioned separately, approximately 10 months apart. Commissioning activities involve the following general steps:

- Production wells have a warm-up duration of 12 to 16 hours for the first well, followed by 16 to 24 hours for the next two wells (combined). Steam from well warm-ups vents to the PTU at a rate of 250,000 pounds per hour (lbs/hr) per well.
- Production piping and equipment have a warm-up duration of 24 to 32 hours. Steam is vented at a rate of 350,000 lbs/hr to the rock muffler.
- Steam blow has a duration of 16 to 24 hours with steam venting at 750,000 lbs/hr to the rock muffler.
- Turbine and auxiliary loops preheat with a duration of 18 to 24 hours. The total steam flow rate is 350,000 lbs/hr; 50,000 lbs/hr steam flows through the turbine, condenser and RTO, and the balance of 300,000 lbs/hr of steam flows to the rock muffler.
- Turbine load test with a duration of 18 to 24 hours, full steam flow rate of 750,000 lbs/hr through the turbine, condenser and RTO, with no venting of steam directly to atmosphere.
- Turbine performance test has a duration of 18 to 24 hours, with a steam flow rate of 750,000 lbs/hr through the turbine, condenser and RTO, with no venting of steam to atmosphere.

Commissioning emissions for one power block are shown in Table 5.2-21. Detailed commissioning emission calculations are provided in Appendix E.3.

Table 5.2-21 Commissioning Emissions, One Power Block

Pollutant	Lbs/event
NOx	30.69
ROC	171.57
CO	17.70
SO_2	88.63
PM10	129.39
PM2.5	129.39
Emissions are per event, one power block only.	

Operating Emissions

Operating emissions involve the startup, shutdown and normal operations of the PGF, which includes the operation of the steam turbine with associated emission control equipment and cooling tower. In addition, routine testing and maintenance of the emergency engines are included in normal operations.

Normal Operation

Emissions from normal operation are attributed to the air contaminants that are present in the NCG that are released from the brine with the steam phase. The Applicant has detailed information derived from existing operating plants that demonstrate the ratio of NCG to brine, NCG to steam, and the composition of the NCG. This information was used in conjunction with steam flow rates to estimate the uncontrolled emissions. Controlled emissions were estimated based on the uncontrolled emission rate and the control efficiency of the RTO and scrubber, plus the emissions associated with fuel combustion in the RTO. Normal operating emissions associated with NCG from the steam turbine are always controlled.

Normal operation is expected to occur 8,760 hours per year, and will involve the operation of all three power blocks at steam flow rates of 750,000 lbs/hr for each power block. Steam is processed through the steam turbine and condenser. NCG are then processed through the RTO and associated scrubber (one RTO and scrubber per power block) for emissions control. Normal operating emissions from the Project vent through the RTO scrubber stack, and include products of combustion from the RTO, plus the byproducts of NCG oxidation. Normal operating emissions for one power block and for the Project are shown in Table 5.2-22. Detailed operating emission calculations are provided in Appendix E.3.

Table 5.2-22 Normal Operating Emissions

Pollutant	Lbs/hr	Lbs/day	Tpy
NOx	1.28	30.69	5.60
ROC	0.46	11.02	2.01
CO	0.74	17.70	3.23
SO_2	5.36	128.66	23.48
PM10	0.07	1.65	0.30
PM2.5	0.07	1.65	0.30
Table reflects emissions from normal operations of the Amended Project, all three power blocks, 24 hours per day, 8,760 hours per year.			

Startup and Shutdown

Similar to commissioning, emissions from startup and shutdown are attributed to the air contaminants that are present in the NCG that are released from the brine with the steam phase. Uncontrolled emissions are expected during specific phases of startup and shutdown and are emitted through either the PTU or rock muffler. Other phases of startup and shutdown will involve venting the NCG through the RTO for emissions control.

As compared to the original project, brine flow to the individual power blocks is substantially less(approximately 18 million pounds per hour for the original project and approximately 6.3 million pounds per hour for each Amended Project power block). Therefore, volumes of NCG vented through the PTU and rock muffler are proportionally less during start-up and shutdown events. However, the Applicant, intends to adopt the existing COCs associated with these events (see Section 5.2.7 below).. As CEC found these COCs adequate for the original brine flow and associated NCG release, they are sufficient to accommodate the start-up and shutdown releases associated with the Amended Project's individual power blocks' lower brine flow (i.e., and NCG release). For these reasons, startup and shut-down events were not therefore, modeled in the development of this Amendment Petition.

During startup, the following activities are expected to occur:

- Production wells have a warm up duration of 12 to 16 hours for the first well, followed by 16 to 24 hours for the next two wells (combined). Steam from well warm up vents to the PTU at a rate of 250,000 lbs/hr per well.
- Production piping and equipment have a warm up duration of 24 to 32 hours. Steam is vented at a rate of 350,000 lbs/hr to the rock muffler.
- Turbine and auxiliary loops preheat has a duration of 18 to 24 hours. The total steam flow rate is 350,000 lbs/hr; 50,000 lbs/hr steam flows through the turbine, condenser and RTO, and the balance of 300,000 lbs/hr of steam flows to the rock muffler.

- Auxiliary equipment startup has a duration of 8 to 12 hours. A slip stream of steam at a flow rate of 80,000 lbs/hr is directed to the auxiliary equipment which flows to the condenser and RTO, with the balance of the steam flow of 270,000 lbs/hr vented to the rock muffler.
- Full functional trip test with a duration of 6 to 8 hours, venting steam at a flow rate of 350,000 lbs/hr to the rock muffler.
- Steam delivery to the turbine at gradual increase of steam from 350,000 lbs/hr to a full production rate of 750,000 lbs/hr over a period of 4 to 6 hours. Steam vents through the turbine, condenser and RTO.
- During shutdowns, the following activities will take place:
  - Turbine taken off line, steam vented to rock muffler, gradual flow reduction from 750,000 to 0 lbs/hr over a period of 8 to 12 hours. The procedure is to take one well offline at a time, meaning the first step will reduce the steam flow rate to 500,000 lbs/hr, followed by a reduction to 250,000 lbs/hr and, finally, the third well is taken off line to drop the steam flow down to zero.
  - After shutting down all three wells, the pipeline is drained of brine, with no steam or other emissions released to atmosphere.

The Applicant anticipates up to four starts and four stops per year. There may be unplanned plant trips; the frequency or duration of those trips cannot be predicted, and emissions from those events are not estimated. Startup and shutdown emissions for one power block and for the Project are shown in Table 5.2-23. Detailed startup and shutdown emission calculations are provided in Appendix E.3.

Table 5.2-23 Startup and Shutdown Emissions

Pollutant	Cold Start Lbs/event	Warm Start Lbs/event	Shutdown Lbs/event
NOx	17.90	1.70	0.00
ROC	124.70	15.65	15.18
CO	10.33	0.98	0.00
SO_2	12.29	4.47	0.00
PM10	75.48	7.19	0.00
PM2.5	75.48	7.19	0.00
Reported emissions are per event, one power block only.			

Cooling Towers

The Amended Project will include three five-cell cooling towers with drift eliminators, one per power block. Total Suspended Particulate (TSP) emissions were calculated based on the maximum water circulation rate and the amount of Total Dissolved Solids (TDS)/Total Suspended Solids (TSS) in the water. The reduction due to the drift eliminator was then applied. PM10 was calculated by assuming 100 percent of TSP is PM10 and 100 percent PM10 is PM2.5. ROC emissions were estimated based on the organic compound concentration in condensate (from an existing operating plant) assuming that all of the organics present volatilize completely. Hourly and annual emissions are listed in Table 5.2-24. Emissions are based on continuous operation up to 8,760 hours per year. Details of the cooling tower emission calculations are in Appendix E.3.

Table 5.2-24 Cooling Tower Emissions

Pollutant	Lbs/hr	Lbs/day	Tpy
NOx	---	---	---
ROC	0.03	0.76	0.14
CO	---	---	---
SO_2	---	---	---
PM10	5.32	127.73	23.3
PM2.5	5.32	127.73	23.3
Table reflects total emissions from three cooling towers, normal operations, 24 hours per day, 8,760 hours per year.			

Emergency Diesel Generator and Fire-Water Pump Engines

The Applicant will operate six emergency generators up to 20 hours per year each for maintenance and testing. Three generator engines are 1.5 megawatt (MW) (2,200 horsepower [Hp]), and three are 1.0 MW (1,500 Hp). NOx, ROC and CO emission factors were set equal to the California Tier 4 emission limits, with the assumption that 95 percent of the emission limit for NOx plus NMHC is NOx. SO_2 emissions were calculated using a fuel sulfur content of 15 ppmw. The PM10 emission factor was set equal to the 0.15 g/Hp-hr limit specified in 17 CCR §93115. Emissions for one 2,200-Hp emergency diesel generator engine and the annual total for three engines are presented in Table 5.2-25, and emissions from one 1,500-Hp emergency diesel generator engine and the total for three engines are presented in Table 5.2-26. Emissions from emergency operation of the engines are not estimated.

Table 5.2-25 1.5 MW Emergency Generator Engine Emissions

Pollutant	One Engine			Project Total
	Lbs/hr	Lbs/day	Tpy	Tpy
NOx	2.43	2.43	0.02	0.07
ROC	1.45	1.45	0.01	0.04
CO	12.69	12.69	0.13	0.38
SO_2	0.02	0.02	0.00	0.00
PM10	0.36	0.36	0.00	0.01
PM2.5	0.36	0.36	0.00	0.01

Table 5.2-26 1.0 MW Emergency Generator Engine Emissions

Pollutant	One Engine			Project Total
	Lbs/hr	Lbs/day	Tpy	Tpy
NOx	1.62	1.62	0.02	0.05
ROC	0.97	0.97	0.01	0.03
CO	8.48	8.48	0.08	0.25
SO_2	0.02	0.02	0.00	0.00
PM10	0.24	0.24	0.00	0.01
PM2.5	0.24	0.24	0.00	0.01

The Amended Project will operate one 200-Hp emergency fire water pump engine up to 50 hours per year for maintenance and testing. NOx, ROC and CO emission factors were set equal to the California Tier 4 emission limits, with the assumption that 95 percent of the emission limit for NOx plus NMHC is NOx. SO_2 emissions were calculated using a fuel sulfur content of 15 ppm by weight. The PM10 emission factor was set equal to the 0.15 g/Hp-hr limit specified in 17 CCR §93115. Emergency fire water pump engine emissions are presented in Table 5.2-27. Emissions from emergency operation of the engine are not estimated.

Table 5.2-27 Emergency Fire Water Pump Engine Emissions

Pollutant	Lbs/hr	Lbs/day	Tpy
NOx	0.13	0.13	0.00
ROC	0.06	0.06	0.00
CO	1.13	1.13	0.03
SO_2	0.00	0.00	0.00
PM10	0.01	0.01	0.00
PM2.5	0.01	0.01	0.00

Details of the emergency diesel generator and fire water pump engines emission calculations are provided in Appendix E.3.

<u>Operations and Maintenance (O&M) Emissions</u>

The facility will require periodic vehicle travel and equipment use for routine maintenance, inspections, and repairs. Criteria pollutant emissions are expected from the combustion of fuels in these equipment and vehicles. Fugitive PM10 emissions are also expected from vehicle traffic on paved and unpaved surfaces. Details of the emission calculations are in Appendix E.3.

Summary of Emissions

Total annual emissions from the Amended Project are shown in Table 5.2-28 below. Annual emissions include four startups, four shutdowns and 8,760 hours of normal operations of the steam turbine and RTO, 8, 760 hours per year of cooling tower operation, 20 hours of operation each for the emergency generator engines and 50 hours per year of operation of the fire water pump engine.

Table 5.2-28 Amended Project Annual Emissions

Pollutant	Lbs/day	Tpy
NOx	42.98	5.76
ROC	19.09	2.50
CO	82.35	3.91
SO_2	128.78	23.52
PM10	131.21	23.78
PM2.5	131.21	23.78
Table reflects emissions for normal operations of Amended Project, 24 hours per day, 8,760 hours per year. Daily emissions include testing of all seven emergency engines on same day. Emissions exclude O&M emissions.		

5.2.5.2 Greenhouse Gas Emissions

The operation of the Amended Project may emit GHGs from sources including: release of dissolved gases from geothermal fluids during brine processing, combustion of natural gas in the RTO, combustion of diesel fuel in the emergency fire water pump and emergency generator engines and fugitive leaks from circuit breakers. GHG emissions may include CO_2, methane (CH_4), nitrous oxide (N_2O) and sulfur hexafluoride (SF_6). The methodology used to calculate GHG emissions from each of these sources is explained below.

Calculation Methodology

GHG emissions from operation of the combustion sources including the RTO and emergency engines were estimated based on the maximum usage of the units by the Project and the emission factors listed in California Climate Action Registry General Reporting Protocol (GRP) (CCAR, 2008a).

To estimate GHG emissions from brine processing, the Applicant used detailed information derived from operating geothermal plants that demonstrate the ratio of NCG to brine, NCG to steam, and the composition of the NCG. The information used in these emission estimates is believed to be representative of the conditions and properties of the brine in the vicinity of the Amended Project; however, minor variability in the properties of the geothermal resource is expected. NCG is known to contain GHG including CO_2 and CH_4. This information was used in conjunction with steam flow rates to estimate the uncontrolled emissions. Uncontrolled emissions would occur whenever steam is vented to the rock mufflers or PTUs. Controlled emissions were estimated based on the uncontrolled emission rate and the control efficiency of the RTO. The RTO will not control CO_2 emissions, but will control CH_4 with 99.9 percent control efficiency.

The annual natural gas usage for the RTOs was estimated based on the predicted operating schedule and maximum fuel consumption rate. The annual diesel usage for the fire water pump and the emergency diesel generator engines was estimated based on fuel consumption rate and the maintenance operating schedule of 20 hours per year for the generator engines and 50 hours per year for the fire pump engine. GHG emissions are not estimated for emergency use of these engines. The SF_6 emission rate is based on the amount of in-use SF_6 and the manufacturer-guaranteed leak rate.

CO_2 equivalence (CO_2e) was calculated using the global warming potential (GWP) provided in Appendix C of the GRP (CCAR 2008b). For example, the GWP of methane is 21 times that of CO_2 and the GWP of N_2O is 310 times that of CO_2.

Summary of GHG Emissions

Total GHG emissions from a single power block are summarized in Table 5.2-29. Additional details of the calculations are provided in Appendix E.3.

Table 5.2-29 Summary of GHG Emissions

Source	CO_2 Emissions, metric tons/year	CH_4 Emissions, metric tons/year	N_2O Emissions, metric tons/year	SF_6 Emissions, metric tons/year	CO_2 Equivalence, metric tons/year
RTO Burner	1,656	0	0	0	1,658
NCG	53,544	0	0	0	53,544
Emergency Generator 1	14	0	0	0	14
Emergency Generator 2	21	0	0	0	21
Fire Pump[1]	1.7	0	0	0	1.7
				Total	**55,238.7**
1. Fire pump emissions are prorated for one power block.					

5.2.5.3 Impacts Assessment

Proposed Models and Analytical Approach

EPA dispersion models used to quantify impacts on the environment surrounding the Project site due to Project emissions include the AERMOD modeling system (version 07026, with the associated meteorological and receptor processing programs AERMET and AERMAP versions 06341) for modeling most facility operational and construction impacts in both simple and complex terrain, the Building Profile Input Program for PRIME (BPIP-PRIME version 04274) for determining building dimensions for downwash calculations in the models, and the SCREEN3 model (version 96043) for determining inversion breakup/shoreline fumigation impacts. These models, along with options for their use and how they were used, are discussed below. These models were used for the following analyses:

- Comparison of operational and construction impacts to significant impact levels, CAAQS, and NAAQS using AERMOD;

- Cumulative impacts analyses with AERMOD in accordance with local/state/EPA/CEC requirements; and
- Assessment of impacts to soil and vegetation.

Load Screen Modeling

The Project is anticipated to be operated as a base load facility and, therefore, an initial load screening analysis was not conducted to identify which operating conditions cause worst-case ambient air impacts. As a result, the refined modeling was provided for Project operating emissions.

Refined Modeling

The purpose of the refined modeling analysis was to demonstrate that air emissions from the Amended Project will not cause or contribute to a violation of NAAQS or CAAQS. For modeling the Project's operational impacts under normal conditions and temporary project construction impacts, AERMOD was used with five years of hourly meteorological data from the Imperial County Airport.

AERMOD is a steady-state plume dispersion model that simulates transport and dispersion from multiple point, area, or volume sources based on characterizations of the atmospheric boundary layer. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions; the vertical distribution for convective conditions is based on a bi-Gaussian probability density function of the vertical velocity. For elevated terrain, AERMOD incorporates the concept of the critical dividing streamline height in which flow below this height remains horizontal, and flow above this height tends to rise up and over terrain. AERMOD also uses the advanced PRIME algorithm to account for building wake effects.

For regulatory applications of AERMOD, the regulatory default option was selected (i.e., the parameter DFAULT was employed in the MODELOPT record in the Control Pathway). The DFAULT option requires the use of terrain elevation data, stack-tip downwash and sequential date checking, and does not permit the use of the model in the SCREEN mode. In the regulatory default mode, pollutant half-life or decay options are not employed. AERMOD incorporates the PRIME algorithms for the simulation of aerodynamic downwash induced by buildings.

These effects are important because many of the emission points are below Good Engineering Practice (GEP) stack height. If an emission point is less than GEP, then the effects of downwash are calculated in the modeling analysis. All point source locations used in the normal modeling analysis considered the potential for downwash impacts. The area around both the meteorological monitoring location and the Project site are considered rural, so urban options (either in Control or Source Pathways) were not employed. Flagpole receptors were not used. AERMAP was used to calculate receptor elevations and hill height scales for all receptors from 30-meter Digital Elevation Model (DEM) data in accordance with EPA guidance.

For the assessment of cooling tower emissions, the cooling tower vendor provided two ambient operating conditions (summer and winter), which were used to determine worst-case air impacts. Specifically, the vendor provided the temperature differential (ΔT) between the entering ambient air and the cooling tower exit temperature for both the winter and summer cases. The winter case ΔT was 28.2°F and the summer case was 6.7°F. Since AERMOD has the capability to model ΔT for stacks, the ΔT that would produce the smallest amount of buoyancy flux was used as the exit temperature for the cooling towers.

Annual NO_2 concentrations were calculated using the Ambient Ratio Method, adopted in Supplement C to the Guideline on Air Quality Models (EPA, 1994). The Guideline allows a nationwide default conversion rate of 75 percent for annual NO_2/NOx ratios. If one-hour NO_2 standards were exceeded, then the Ozone Limiting Method (OLM) was used with hourly ozone data collected near the Project site. The hourly ozone data were input into the AERMOD dispersion model to calculate the one-hour NO_2 impacts.

Fumigation Effects

Air dispersion modeling analysis can account for the natural occurrence of increased in air concentrations due to temperature through what is called shoreline and inversion breakup fumigation effects. The Amended Project was determined to not be susceptible to shoreline fumigation, as described below. However, a screen modeling analysis was used to evaluate inversion breakup effects.

Shoreline fumigation is the process in which a plume, emitted into a stable marine layer, intersects a thermally unstable layer over land. The plume travels with relatively little diffusion in this stable layer, but upon intersecting the thermally unstable layer over land, fumigation can occur leading to high ground level concentrations. Internal boundary layers develop near a coastline because of the two basic physical differences between land and water: roughness and temperature (the change in surface heating due to the difference in surface temperature between land and water). Roughness over the water is generally less than roughness over the land. Frictional effects on air moving over a water surface are minimal and mechanical turbulence produced by varying wave heights is generally low. The mechanical turbulence produced by roughness elements over land may be quite high. Thus, with onshore flow, a mechanically-forced internal boundary layer develops from the change in shear stress because of the roughness discontinuity present at the shoreline.

The formation of a Thermal Internal Boundary Layer (TIBL) is based on flow adjustment theory. An air mass advected over a cold lake or ocean surface is not destabilized by convective elements as would an overland air mass. Instead, the marine air mass cools from below via conduction from the cold water's surface and thus becomes stable. As the stable marine layer crosses the shoreline (i.e., onshore flow) it must adjust itself, first in the lowest levels, then in the higher levels, to the resulting discontinuity in temperature between the water and land. This adjustment is accomplished by the generation of turbulence which acts as a transport mechanism for surface heat from the land surface. The TIBL interface generally slopes upward from the coastline until at some point downwind it assumes an equilibrium height, which is the height of the inland mixed layer.

The land-water interface of the Salton Sea does not likely generate the physical and dynamical processes needed for shoreline fumigation for the following two reasons. First, the area surrounding the Salton Sea is classified as desert and any air mass advected over the Salton Sea already is characteristic of a desert. The Salton Sea is not a large water body when compared to the land mass surrounding it, nor is it considered a cold mass of water. Typically, air masses advected over cold water surfaces need large amounts of time and distance to acquire a stable marine characteristic. Given the limited size of the water body, and the fact that the Salton Sea is not considered a cold body of water, it is doubtful that a desert air mass will become a stable marine layer as it is transported over the Salton Sea. Second, because the Project is located in flat desert terrain, which is somewhat similar to the roughness length of water, there is not a large difference in roughness length between the water and land, which is needed for the formation of shoreline fumigation.

Thus, the needed physical processes for the generation of a stable marine layer don't exist in the Project area. Shoreline fumigation is not expected to occur in this desert climate since the Salton Sea lacks the size or temperature structure needed to form such a stable marine layer.

To evaluate inversion breakup fumigation impacts the SCREEN3 model was used following the methodology in EPA 454/R-92-019, Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised. Fumigation-impact analysis included evaluating the impacts of the Amended Project during inversion breakup events.

Receptor Grids

Receptor and source base elevations were determined from US Geological Survey (USGS) DEM data using the most recent 7½-minute format (i.e., at this time, only DEM files with 30-meter spacing between grid nodes are available). All coordinates were referenced to Universal Transverse Mercator (UTM) North American Datum 1927 (NAD27), zone 11. The receptors from the DEM files were placed exactly on the DEM nodes. Every effort was made to maintain receptor spacing across DEM file boundaries.

Cartesian coordinate receptor grids were used to provide adequate spatial coverage surrounding the Project area for assessing ground-level pollutant concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. The maximum extent of the significant impact isopleth for any pollutant was used to represent the impact radius.

For the full impact analyses, a nested grid was developed to fully represent the significance area(s) and maximum impact area(s). The downwash receptor grid had a receptor spacing of 30 meters along the facility fence line and out to 0.5 kilometers (km) from the Project site; 90-meter spacing out to 2.0 km from the Project site; and the coarse receptor grid had a 210-meter receptor spacing that extended outwards at least 10 km (or more as necessary to calculate the significant impact area). This receptor grid is slightly different than the one proposed in the Modeling Protocol. Specifically, the 30 meter grid was reduced to 0.5 km from the Project site from 2.0 km in order to decrease the overall run-time of each AERMOD model run. When maximum impacts occurred in areas outside the 30-meter spaced receptor grids, additional refined receptor grids with 30-meter resolution were placed around the maximum impacts and extended as necessary to determine maximum impacts. Ambient concentrations within the facility fence line were not calculated. DEM receptor data were input into AERMAP (version 06341) to calculate hill height scales as per EPA guidance.

Model Options and Impacts

The AERMOD model allows the selection of a number of options that affect model output. The regulatory default options were used that included:

- Elevated terrain effects;
- Stack tip downwash; and
- Calms processing.

An analysis was performed to determine whether to if the “urban” option should be used. This analysis used the procedures of Auer (1978) and included drawing a three-kilometer radius around the Project site. Within this region, land use was classified as either rural or urban. Over 95 percent of the land use within three kilometers of the Project site was identified as rural. Therefore, the urban option was not used in the modeling analysis.

As part of the AERMET input requirements, Albedo, Bowen Ratio, and Surface Roughness were classified. The AERSURFACE program was used to generate the surface characteristics for use in AERMET as specified in EPA’s January 2008 AERMOD Guidance Document and AERSURFACE User’s Guide using default settings where appropriate. AERSURFACE was executed for two sectors (Sector 1 = 110º-355º and Sector 2 = 355º-110º) to define surface roughness. The actual values are presented in the modeling protocol (see Appendix E.2).

Building Wake Effects

Stack locations and heights, and building locations and dimensions will be input to BPIP-PRIME. The first part of BPIP-PRIME determined and reported on whether a stack is being subjected to wake effects from a structure or structures. The second part calculates direction-dependent “equivalent building dimensions” if a stack was being influenced by structure wake effects. The BPIP-PRIME output was formatted for use in AERMOD input files.

Meteorological Data and Site Representation

The Applicant used recent five years (2002-2006) of meteorological data collected at the Imperial County Airport, which is approximately 22 miles south from the Project site, and believes use of these data satisfies the criteria for use as “onsite data”. The meteorological data collected at Imperial County Airport accurately represents meteorological conditions at the Project site because there is no terrain or other steering mechanisms that would have a significant affect on the meteorology at the Project site. The surface roughness, height, and length of the large-scale terrain features are consistent throughout the area, and play a large role in the affect on the horizontal and vertical wind patterns. There is no slope aspect in the vicinity of the site that would reasonably affect the wind direction or speed. The mesoscale features at both the Project site and the Imperial County Airport site are similar.

Meteorological data were used in two ways. First a long-term record of meteorological data defines the overall climate of a region. Second, hourly meteorological observations of certain parameters were used to define the area’s dispersion characteristics. These data were used in the air dispersion models described above for defining the Project’s impact on air quality.

Preparation of the Meteorological Data Set

The Applicant used the formatted meteorological data collected at Imperial County Airport from 2002 through 2006 in the atmospheric dispersion modeling analyses. The data was preprocessed for direct use by the AERMET (version 06341) preprocessor model. Surface data were acquired from the nearest available representative surface weather station at Imperial, California (WBAN 03144). As recommended by the EPA in the Guideline on Air Quality Models (EPA, 2000), five years of meteorological data are used. National Climatic Data Center provided the data. Upper air data for the same time period was taken from the closest representative National Weather Service radiosonde station that, when combined with the proposed surface dataset, meet the EPA required data recovery rates of 90 percent. The radiosonde station used was Tucson, Arizona. Any missing data were substituted as per EPA recommended procedures, as discussed in the EPA memorandum (Lee, R. & Atkinson, D., 1992). Periods with more than one consecutive missing hour of wind speed or wind direction were set to calm/missing to ensure that worst-case predicted impacts were not derived from interpolated meteorological conditions.

Construction

Analysis of Ambient Impacts from Facility Construction

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

Existing Ambient Levels

As with the modeling analysis of Project operating impacts (see below), monitoring stations identified in Section 5.2.3.2 were used to establish the ambient background levels for the construction impact modeling analysis. Existing air quality data are available from several monitoring sites in the regional area and have been used to derive background levels for several pollutants. The maximum air quality values over the past three years of data available in Imperial County or the Salton Sea Basin are presented below in Table 5.2-30.

Table 5.2-30 Background Air Quality Values

Pollutant and Averaging Time	Background Value[1] μg/ m^3
PM10, 24-hour	291.0
PM10, Annual	56.4
PM2.5, 24-hour	57.9
PM2.5, Annual	9.4
CO, 1-hour	16,345.0
CO, 8-hour	8,870.0
NO_2, 1-hour	215.1
NO_2, Annual	22.6
SO_2, 1-hour	499.2
SO_2, 3-hour	431.6
SO_2, 24-hour	49.4[2]
SO_2, Annual	2.6

Table 5.2-30 Background Air Quality Values

Pollutant and Averaging Time	Background Value[1] µg/ m³
1. High values for all years, all applicable stations. The gaseous pollutant conversion factors used were 1,143, 1,887, and 2,600 (ug/m³)/(ppm) based on the 1-hour CO, annual NO_2, and 3-hour SO_2 NAAQS, respectively. 2. Value used is the second highest value for the period. The highest value was determined by CARB to be invalid (CARB 2008e).	

Dispersion Model

As in the analysis of Project operating impacts, the USEPA-approved model AERMOD (version 07026) was used to estimate ambient impacts from construction activities. A detailed discussion of the AERMOD dispersion model and the associated processing programs AERSURFACE, AERMET, and AERMAP is included above.

There are four primary construction activities associated with the Project: 1) power block construction, 2) well drilling onsite, 3) well drilling offsite, and 4) earthwork activities. Not all of these construction activities will take place during the same time periods (i.e., hourly and daily). However, where there is overlap between the four primary construction activities on an hourly or daily basis, construction activities were modeled cumulatively. For example, well drilling activities both onsite and offsite will occur at the same time, and were therefore modeled concurrently. Other than drilling rigs, combustion source exhaust emissions were modeled as 3.048 meter high point sources (exhaust parameters of 750 degrees Kelvin, 64.681 meters per second (m/s) velocity, and 0.1524 meter diameter). Drilling rig exhaust emissions were assumed to be the same as the 1.5 MW emergency generator engines modeled for facility operations.

For power block construction, the emission sources were grouped into two categories: exhaust emissions and fugitive dust emissions. All combustion equipment emission from onsite motor vehicles and construction equipment were modeled collectively as 20 point sources spread evenly at 100-meter intervals across the power block and construction laydown areas. Construction fugitive dust emissions were modeled as an area source covering the power block and laydown areas with an effective plume height of 0.5 meters.

For the onsite and offsite well drilling construction, the combustion equipment emissions from the drill rig engines and bulldozer were grouped and modeled using the drill rig stack parameters. Additionally, each drill rig (one each in onsite and offsite locations) consists of three engines each that were modeled as a single point source. Onsite motor vehicle emission associated with construction activities were modeled as four point sources spaced evenly across each drilling location. As construction and drilling activities would occur at one onsite drilling location and one offsite drilling location during the worst-case hour and day, these well pad locations were modeled cumulatively. The fugitive dust emissions were modeled as area sources with an effective plume height of 0.5 meters covering the entire area of each of two drilling locations. Drilling activities for each power block were modeled separately as source groups. The source group that produced the largest impacts was used to represent the total impacts from this construction activity.

For earthwork construction, the combustion equipment emission from earthmoving equipment and onsite motor vehicles were modeled as point sources spaced evenly across the Project site. For onsite construction activities, nine point sources spaced at 250 meter intervals over the entire area, up to the property fence line, were modeled. For offsite construction activities, seven point sources spaced at 200-meter intervals over the borrow pit area were modeled. Both onsite and offsite activities were modeled cumulatively. The fugitive dust emissions were modeled as area sources with an effective plume height of 0.5 meters covering the entire area of the two earthwork activity locations described above.

Combustion and fugitive dust emissions were assumed to occur for eight hours per day (8 AM to 4 PM). The construction impacts modeling analysis used the same initial receptor grids and meteorological data as used for the Project operating impact analysis. Since construction activities in offsite areas were modeled without restricting receptor placement near these activities, refined 30-meter receptor grids were not used for maximum impacts in 90-meter spaced receptor areas. A detailed discussion of the receptor locations and meteorological data is included elsewhere in this section. For the construction impacts modeling involving area sources, the TOXICS keyword was used to minimize execution times.

Modeling Results

Based on the emission rates of NOx, SO_2, CO, PM2.5, and PM10, the modeling options, receptor grids, and meteorological data, AERMOD calculates short-term and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour, 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NOx, SO_2, CO, PM2.5, and PM10 spread over the estimated daily hours of construction. The annual impacts are based on the worst-case annual emission rates of these pollutants.

The annual average concentrations of NO_2 were computed following the revised EPA guidance for computing these concentrations (Federal Register, 60 FR 40465, August 9, 1995). The annual average was calculated using the ambient ratio method (ARM) with the national default value of 0.75 for the annual average NO_2/NOx ratio.

The modeling analysis results are shown in Tables 5.2-31 through 5.2-33 for the four construction activities. Also included in the tables are the maximum background levels that have occurred in the last three years and the resulting total ambient impacts. As shown in the tables below, modeled construction impacts for SO_2 and CO pollutants are expected to be below the most stringent State and Federal standards, while NO_2, PM10 and PM2.5 impacts exceed standards. Total combined (modeled plus background) impacts are greater than the 1-hour NO_2 state standard and the 24-hour and annual average PM10 and PM2.5 standards.

Table 5.2-31 Modeled Maximum Power Block Construction Impacts

Pollutant	Averaging Time	Maximum Construction Impacts µg/m³	Background µg/m³	Total Impact µg/m³	State Standards µg/m³	Federal Standards µg/m³
NO_2[a]	1-hour Annual	231.5 1.6	215.1 22.6	466.6 24.2	339 57	- 100
SO_2	1-hour 3-hour 24-hour Annual	0.3 0.1 0.04 0.003	499.2 431.6 49.4 2.6	499.5 431.7 49.4 2.6	655 - 105 -	- 1,300 365 80
CO	1-hour 8-hour	198 87.3	16,345 8,870	16,543 8,957	23,000 10,000	40,000 10,000
PM10	24-hour Annual[b]	1308 7.2	291.0 56.4	1,599 63.6	50 20	150 -
PM2.5	24-hour Annual	277 1.6	57.9 9.4	335 11.0	- 12	35 15

Notes:
[a]ARM applied for annual average, using national default 0.75 ratio.
[b]Annual Arithmetic Mean.

Table 5.2-32 Modeled Maximum Onsite and Offsite Well Drilling Construction Impacts

Pollutant	Averaging Time	Maximum Construction Impacts µg/m³	Background µg/m³	Total Impact µg/m³	State Standards µg/m³	Federal Standards µg/m³
NO_2[a]	1-hour Annual	120.5 4.7	215.1 22.6	335.6 27.3	339 57	- 100
SO_2	1-hour 3-hour 24-hour Annual	0.7 0.6 0.2 0.06	499.2 431.6 49.4 2.6	499.9 432.2 49.6 2.7	655 - 105 -	- 1300 365 80
CO	1-hour 8-hour	386 288	16,345 8,870	16,731 9158	23,000 10,000	40,000 10,000
PM10	24-hour Annual[b]	7,446 24.1	291.0 56.4	7,737 80.5	50 20	150 -
PM2.5	24-hour Annual	1,578 5.2	57.9 9.4	1,636 14.6	- 12	35 15

Notes:
[a] ARM applied for annual average, using national default 0.75 ratio.
[b] Annual Arithmetic Mean.

Table 5.2-33 Modeled Maximum Earthwork Construction Impacts

Pollutant	Averaging Time	Maximum Construction Impacts µg/m³	Background µg/m³	Total Impact µg/m³	State Standards µg/m³	Federal Standards µg/m³
NO_2[a]	1-hour Annual	158.3 1.6	215.1 22.6	373.4 24.2	339 57	- 100
SO_2	1-hour 3-hour 24-hour Annual	0.2 0.1 0.03 0.002	499.2 431.6 49.4 2.6	499.4 431.7 49.4 2.6	655 - 105 -	- 1,300 365 80
CO	1-hour 8-hour	79.8 37.7	16,345 8,870	16,425 8,908	23,000 10,000	40,000 10,000
PM10	24-hour Annual[b]	22.2 5.5	291.0 56.4	313 61.9	50 20	150 -
PM2.5	24-hour Annual	4.9 1.2	57.9 9.4	63 10.6	- 12	35 15

Notes:
[a] ARM applied for annual average, using national default 0.75 ratio.
[b] Annual Arithmetic Mean.

The construction impacts described here are not unusual for construction projects on sites of this size. However, construction projects that use good dust suppression techniques and low-emitting vehicles typically achieve substantial reductions in emissions and resulting impacts. Note that modeling input and output files are provided on CD-ROM as part of the Amendment Petition submittal to the CEC (see Appendix E.5).

Commissioning, Start up and Shutdown

The commissioning activities associated with the Amended Project are substantially reduced when compared to the original project, as each individual power block will be commissioned individually, approximately 10 months apart. Each power block has approximately one-third of the brine flow and steam flow compared to the original project, and thus the potential emissions during these events will be approximately two-thirds lower, and the associated impacts to ambient air quality will be reduced substantially compared to the original project.

The startup activities associated with the Amended Project will be substantially reduced when compared to the original project, as each individual power block will typically be started individually. Each power block has approximately one-third of the brine flow and steam flow compared to the original project, and thus the potential emissions during these events will be approximately two-thirds lower and the associated impacts to ambient air quality will be reduced substantially compared to the original project. Similarly, during controlled shutdowns, one power block would be shut down at a time, reducing emissions associated with these events by two-thirds when compared to the original project, and reducing the impacts to ambient air quality.

During uncontrolled shutdowns (i.e., plant trip), all three power blocks could be shutdown simultaneously, and under these circumstances, the Amended Project emissions and associated impacts would be similar to the original project.

The ambient air quality modeling for the original project concluded that there would be some short-term, unavoidable significant impacts during commissioning, startup, and shutdown of the original project. Measures to minimize emissions are included in the existing COC for the original project.

Because commissioning, startup and shutdown activities associated with the Amended Project will either result in substantially lower emissions and associated impacts, or similar emissions and impacts when compared to the original project, modeling for these short-term events was not conducted for the Amended Project.

Normal Operation

There are several activities that cause air emissions during the operation of the power plants. They include:

- Noncondensible gases being emitted at the cooling towers,
- Offgassing at the cooling towers,
- Drift (i.e., PM10/2.5 emissions) from the cooling towers,
- RTO emissions including criteria pollutants and HAPs, and
- Emergency generators and the fire pump criteria pollutants and HAPs.

The modeling scenarios used to assess their impact on ambient air quality standards are described below. Emissions from the cooling towers were modeled as 15 point sources (each cooling tower has five cells). Exhaust from the RTOs were modeled as three point sources. The emergency generators and fire pump were modeled as seven point sources. The parameters used for emission calculations for cooling towers RTO, emergency generators, and the fire pump are listed in Table 5.2-34.

Table 5.2-34 Operation Modeling Equipment Parameters

Source	Stack Height m	Stack Temperature	Stack Diameter m	Stack Velocity m/s
Cooling Tower	19.8	Varies by ambient temperature; nominal 37°C	9.95	9.6
RTO	19.7	342°K	1.08	11.1
Emergency Generator (480V)	4.7	751°K	0.41	29.5
Emergency Generator (4160V)	4.7	680°K	0.46	31.8
Fire Pump	4.6	665°K	0.15	53.3

For the criteria pollutants, the following averaging periods were modeled:

- 1 hour: H_2S, CO, NO_2, and SO_2
- 3 hour: SO_2
- 8 hour: CO
- 24 hour: SO_2
- Annual: NO_2 and SO_2

Based on the pollutant being modeled, the following sources were assessed for each of the criteria pollutants:

- NO_2 – Emergency equipment and the RTOs
- CO – Emergency equipment and the RTOs
- PM10/2.5 – Emergency equipment, RTOs, and the cooling towers
- H_2S – RTOs and the cooling towers.

Table 5.2-30 represents the highest values reported for any site during any single year of the most recent three-year period. These concentrations were added to the modeled results to calculate the total impact from the Project during normal operations.

Once the modeled impacts were added to background monitoring data, the resultant concentrations were compared with the CAAQS/NAAQS as necessary. Table 5.3-35 summarizes maximum modeled concentrations for each criteria pollutant and associated averaging periods. All modeled concentrations, with the exception of 24-hour and annual PM10 along with 24-hour PM2.5 are less than the CAAQS/NAAQS standards. The background concentrations for the 24-hour and annual PM10 and the 24-hour PM2.5 exceed the applicable AAQS. In these cases, the modeled concentration is compared to the SIL. For normal operations, the modeled PM10 and PM2.5 impacts do not exceed the applicable SILs. Thus, all Project impacts for normal operations, including PM10/2.5 are less than significant.

Table 5.2-35 Air Quality Impact Results for the Refined Modeling Analysis for Normal Operating Conditions

Pollutant	Avg. Period	Maximum Conc. $\mu g/m^3$	Background $\mu g/m^3$	Total $\mu g/m^3$	Class II Significance Level $\mu g/m^3$	Ambient Air Quality CAAQS $\mu g/m^3$	Ambient Air Quality NAAQS $\mu g/m^3$
NO_2	1-hour Annual	85.16 0.17	215.1 22.6	300.26 22.77	- 1	339 56	- 100
CO	1-hour 8-hour	419.97 22.35	16,345 8,870	16,764 8,892	2,000 500	23,000 10,000	40,000 10,000

Table 5.2-35 Air Quality Impact Results for the Refined Modeling Analysis for Normal Operating Conditions

Pollutant	Avg. Period	Maximum Conc. $\mu g/m^3$	Background $\mu g/m^3$	Total $\mu g/m^3$	Class II Significance Level $\mu g/m^3$	Ambient Air Quality CAAQS $\mu g/m^3$	Ambient Air Quality NAAQS $\mu g/m^3$
SO_2	1-hour 3-hour 24-hour Annual	9.07 7.73 4.18 0.896	499.2 431.6 49.4 2.6	508.27 439.33 53.58 3.49	- 25 5 1	655 - 105 -	- 1,300 365 80
PM10	24-hour Annual	3.44 0.81	291.0 56.4	294.44 57.21	5 1	50 20	150 -
PM2.5	24-hour*	2.39	57.9	60.29	5	-	35
H_2S	1-hour	11.88	24.6	36.48	1	42	--
*98th Percentile Concentration							

Fumigation

Fumigation analyses with the EPA Model SCREEN3 (version 96043) were conducted for inversion breakup conditions based on EPA guidance given in “Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised” (EPA-454/R-92-019)). Impacts were evaluated with SCREEN3 for the cooling towers, RTOs, and the emergency generator and fire pump engines. Shoreline fumigation impacts were not assessed.

SCREEN3 predicted inversion breakup impacts only for the cooling tower cells. No inversion breakup fumigation impacts were predicted to occur for emissions from any of the other facility sources (i.e., any of the engines, the fire pump, or the RTOs). An inversion breakup fumigation impact of 8.733 $\mu g/m^3$ for a unitized emission rate (1 gram/second, g/s) was predicted to occur at a downwind distance of 3,875 meters. This result is predicted to occur by SCREEN3 for rural conditions of F stability and 2.5 m/s wind speed at the stack release height.

Inversion breakup impacts are generally expected to occur for periods less than 90 minutes. Therefore, only ambient standards for H_2S were evaluated based on pollutants expected to be emitted by the cooling tower cells. The maximum H_2S inversion breakup impact would be 4.40 $\mu g/m^3$, calculated by conservatively combining the impact for all three cooling towers (i.e., 8.733 ($\mu g/ m^3$)/(g/s) x 0.0336 g/s/cell x 3 cooling towers x 5 cells/cooling tower). This is significantly less than the maximum H_2S impact predicted to occur for the cooling tower cells by AERMOD of 5.97 $\mu g/ m^3$.

Since 1-hour H_2S fumigation impacts are less than the maximum overall AERMOD 1-hour impacts, no further analysis of additional short-term averaging times (3-hour, 8-hour, or 24-hour) is required as described in Section 4.5.3 of “Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised” (EPA-454/R-92-019).

Soil and Vegetation Analysis

The Amended Project stack emissions CO, PM10, and NOx and SO_2 from the RTO stacks and cooling towers were evaluated to determine potential impacts to surrounding soil and vegetation. Based on the AERMOD modeling results, no pollutant emissions are predicted to result in concentrations exceeding the EPA prevention of significant deterioration (PSD) significant impact levels, for either short-term or annual averaging periods for CO, PM10, NOx, and SO_2. Table 5.2-36 presents the total maximum impact concentrations from the Amended Project.

The results of the evaluation of Amended Project stack emissions are discussed below.

Carbon Monoxide

Plants metabolize and produce CO. However, few studies on thresholds for detrimental effects on vegetation from exposure to CO have been conducted. Most available studies use very high CO concentrations (above 100 parts per million [ppm]). Soil microorganisms probably act as a buffering system and sink for CO. There are no known detrimental effects on plants due to CO concentrations of 10,000 to 230,000 $\mu g/m^3$ (EPA, 1979).

Zimmerman et al. (1989) exposed a variety of plant species to CO at concentrations of 115,000 $\mu g/m^3$ to 11,500,000 $\mu g/m^3$ from 4 to 23 days. While practically no growth retardation was noted in plants exposed at the lower level, retarded stem elongation and leaf deformation were observed at the higher concentrations. Pea and bean seedlings also exhibited abnormal leaf formation after exposure to CO at 27,000 $\mu g/m^3$ for several days (EPA, 1979).

Comparatively low levels of CO in the soil have been shown to inhibit nitrogen fixation. Concentrations of 113,000 $\mu g/m^3$ have been shown to reduce nitrogen fixation, while 572,000 to 1,142,000 $\mu g/m^3$ result in nearly complete inhibition (EPA, 1979).

Maximum predicted 1-hour and 8-hour CO emissions have been calculated from the RTO exhaust stack. The maximum 1-hour CO concentration is 419.97 $\mu g/m^3$. This figure is substantially less than the CO concentration of 115,000 $\mu g/m^3$ determined to result in minimal growth retardation in plants, as well as the 113,000 $\mu g/m^3$ concentration found to result in slight reduction of nitrogen fixation. Therefore, predicted CO emission levels from the Amended Project are not expected to result in adverse effects on vegetation.

Sulfur Dioxide and Nitrogen Oxides

SO_2 is the major airborne pollutant of concern for the Amended Project; NOx emissions are comparatively low. The extent of the effect of SO_2 and NOx emissions have on soils and vegetation would be directly related to a variety of factors, including wind speed, direction and frequency, air temperature, humidity, the geomorphology of the area, and the location of the Amended Project in relation to sensitive plant communities in the zone of impact. Environmental factors, such as temperature, light, humidity, and wind speed, influence both the rate of gas absorption and the plant physiological response to absorbed quantities— the higher the humidity, the higher the absorption of gases. Exposure duration and frequency are also important factors that determine the extent of injuries.

Guidelines for air emission impact assessment provided in the technical literature are diverse, and threshold dosages required to cause injury are extremely variable. This is due to the variety of factors affecting plant responses to phototoxic gases. Consequently, in cases where emissions are below lower threshold limits, decreased yields can result in the absence of visible injury (Sprugel et al. 1980) and long-term impacts should be addressed.

SO_2 can affect vegetation directly (as a gas), or indirectly by means of its principal reaction product, sulfate (e.g., acidification of soils). In addition, a third mechanism of impact is the formation and deposition of acid mist. Direct effects of injury can be manifested as foliar necrosis, decreased rates of growth or yield, predisposition to disease, and reduced reproductive capacity.

Among the different published attempts to define SO_2 thresholds for vegetation effects, two represent worst-case situations. Loucks et al. (1980) presented threshold ranges between 131 μg/m^3 and 262 μg/m^3 SO_2, and McLaughlin (1981) suggested values of 1,310 μg/m^3 SO_2 for the 1-hour average and 786 μg/m^3 for the 3-hour average.

According to the dose-injury curve for SO_2-sensitive plant species provided by the US Fish and Wildlife Service (USFWS) (1978), the lowest 3-hour concentration expected to cause injury to plants is approximately 390 μg/m^3, which is significantly higher than the projected emissions from the Amended Project. However, these predicted values are applicable only when plants are growing under the most sensitive environmental conditions and stage of maturity. Thresholds for chronic plant injury by SO_2 have been estimated at about 130 μg/m^3 on an annual average basis (USFWS, 1978). The maximum annual average concentration modeled for the Project (0.896 μg/m^3) is substantially below the USFWS threshold for chronic exposure, and the worst-case projected 3-hour maximum of about 7.73 μg/m^3 is substantially below the McLaughlin protection level of 786 μg/m^3. Consequently, the predicted maximum concentration of SO_2 from the Amended Project is not expected to cause visible foliar injury or significant adverse chronic effects.

SO_2 tends to convert to sulfite and sulfate during chemical transformation in soils. Interpretation of the results of investigations published to date has engendered considerable controversy due to the complexity of terrestrial ecosystems. However, the effects of acidified precipitation containing sulfate on terrestrial ecosystems have been investigated with respect to alteration of soil chemistry as it relates to vegetation health. High levels of sulfate may reduce soil pH, thereby decreasing the availability of certain essential nutrients and increasing the concentrations of soluble aluminum, which reduces plant growth.

Sulfur is a major plant nutrient and can be directly absorbed into the soil. Therefore, an increase in SO_2 in the soil (particularly at levels below threshold limits) would not have an adverse effect on vegetation.

NO_2 is potentially phytotoxic, but generally at exposures considerably higher than those resulting from most industrial emissions. Exposures for several weeks at concentrations of 280 to 490 μg/m^3 can cause decreases in dry weight and leaf area, but 1-hour exposures of at least 18,000 μg/m^3 are required to cause leaf damage. The modeled impacts of maximum Project emissions of 85.16 μg/m^3 are substantially below these threshold limits (219.0 μg/m^3 or 0.1169 ppm). In addition, the total predicted maximum 1-hour NO_2 concentrations of 300.26 μg/m^3 are substantially less than the 1-hour threshold (7,500 μg/m^3 or 3,989 ppm) for five percent foliar injury to sensitive vegetation (EPA, 1991). This indicates that NOx emissions from the Amended Project, when considered in the absence of other air pollutants, would not adversely affect vegetation.

NOx tends to convert to nitrates in soils. In soils, where nitrate-nitrogen is not limiting plant growth, excess nitrate may percolate through the soil column, carrying base cations and exerting an acidifying effect. Increased atmospheric contributions of nitrate may influence vegetation in a species-specific way, with some species taking advantage of its fertilizing characteristics while others (such as those occurring in nitrogen-limited soils) are adversely affected.

Airborne Particulate Matter

Particulate emissions from the cooling towers will be controlled with a high-efficiency mist eliminator. The water quench and scrubber flow to the RTO likely will control PM10 emissions from the RTO, although the quench and scrubber are installed for other purposes. The deposition of airborne particulates (PM10) can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Information on physical effects is scarce, presumably in part because such effects are slight or not obvious except under extreme situations (Lodge et al., 1981). Studies performed by Lerman and Darley (1975) found that particulate deposition rates of 365 g/m^2/year caused damage to fir trees, but rates of 274 g/m^2/year and 400 to 600 g/m^2/year did not damage vegetation at other sites.

The maximum annual predicted concentration for PM10 from the Amended Project is 0.81 $\mu g/m^3$. Assuming a deposition velocity of two cm/sec (worst-case deposition velocity, as recommended by the CARB), this concentration converts to an annual deposition rate of 0.511 g/m^2/year, which is several orders of magnitude below the concentration that would be expected to result in injury to vegetation (i.e., 365 g/m^2/year).

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

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

Cooling Tower Discharges

Contaminants within the Amended Project cooling tower drift are expected to consist almost entirely minerals. Metals and other chemicals of concern will be neutralized and removed from the cooling tower makeup water before it is introduced into the plant cooling water system.

PM10 emissions from the RTO stacks and cooling towers were calculated for the Amended Project. The maximum annual deposition rate for the Amended Project of 0.81 g/m^2/year is several magnitudes below the rate that would be expected to result in mechanical injury to vegetation (i.e., 365 g/m^2/year; see previous discussion on airborne particulates; Lerman and Darley 1975).

Various inorganic compounds (e.g., salts) from cooling water are expected to be in the cooling tower water. These low levels of salts are not expected to result in injury to the surrounding environment. Pahwa and Shipley (1979) exposed vegetation (corn, tobacco, and soybeans) to varying salt deposition rates to simulate drift from cooling towers that use saltwater (20 to 25 parts per thousand) circulation. Salt stress symptoms on the most sensitive crop plants (soybeans) were barely perceptible at a deposition rate of 2.98 g/m^2/year (Pawha and Shipley 1979). Using an assumption that 100 percent of the airborne particulates from the Amended Project emissions produce salts in the cooling tower drift, the calculated deposition rate of 0.19 g/m^2/year (which includes RTO stack emissions) is more than one order of magnitude below the deposition rate that was shown to cause barely perceptible vegetation stress from salt mist. This highly conservative estimate of deposition, combined with the fact that the Amended Project cooling tower will use condensate as make-up water renders this evaluation considerably overstated. Therefore, cooling tower drift is not expected to have any impact on vegetation in surrounding habitats within the maximum impact radius for the Amended Project cooling tower drift.

Conclusions

Based on this evaluation, NOx, SO_2, CO and PM10 emissions from the RTO stacks and cooling tower drift will not have a significant adverse impact on vegetation and soils surrounding the Amended Project area.

5.2.6 Mitigation Measures

Air Quality mitigation measures are embodied in the CEC's COC for the original project. These COCs have been adopted and modified by the Applicant to make them appropriate for the Amended Project in the following section.

5.2.7 Conditions of Certification

The COC provided in the Commission's Decision for the original SSU6 project are shown below. The Applicant proposes a number of changes to these Conditions for the Amended Project. Recommended changes are indicated using *italics* for additional text and ~~strikethrough~~ for deleted text.

The Applicant is requesting several changes to the Conditions of Certification. These changes can be attributed to one or more of the following circumstances:

- The Amended Project does not exceed the ICAPCD offset threshold for PM10 emissions, thus conditions related to PM10 offset requirements and/or emission limitations are not necessary or appropriate;
- The Amended Project does not cause an exceedance of CAAQS for H_2S, thus conditions related to H_2S offset requirements are not necessary or appropriate, and monitoring of background H_2S levels is unnecessary;
- Low sulfur (i.e., 15 ppmw) diesel fuel is readily available and the Applicant has committed to use low sulfur diesel, regardless of how far from the Project site it is available;
- The H_2S control technology has been changed from LO-CAT and carbon adsorber to an RTO and scrubber, and thus any conditions that reference the original project's H_2S abatement technology have been either deleted or modified;
- Because the control efficiency of an RTO is temperature dependent, temperature is an appropriate measure of an RTO's control efficiency and thus a continuous emissions monitoring system for H_2S is unnecessary; and
- Dilution water heaters are not part of the Amended Project, and thus references to them are no longer appropriate.

CONSTRUCTION CONDITIONS OF CERTIFICATION

AQ-C1 The project owner shall fund all expenses for an on-site air quality construction mitigation manager (AQCMM) who shall be responsible for maintaining compliance with conditions AQ-C2 through AQ-C4 for the entire project site and linear facility construction. The on-site AQCMM shall have full access to areas of construction of the project site and linear facilities, and shall have the authority to appeal to the CPM to have the CPM stop any or all construction activities as warranted by applicable construction mitigation conditions. The on-site AQCMM shall have a current certification by the California Air Resources Board for Visible Emission Evaluation prior to the commencement of ground disturbance. The on-site AQCMM shall not be terminated without written consent of CPM.

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, current ARB Visible Emission Evaluation certificate, and contact information for the on-site AQCMM.

AQ-C2 The project owner shall provide a construction mitigation plan (CMP) for approval, which shows the steps that will be taken, and reporting requirements to ensure compliance with conditions AQ-C3 through AQ-C4.

Verification: At least 60 days prior to start any ground disturbance, the project owner shall submit the construction mitigation plan to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. Otherwise, the plan shall be deemed approved.

AQ-C3 The on-site AQCMM shall submit to the CPM, in the monthly compliance report (MCR), a construction mitigation report that demonstrates compliance with the following mitigation measures:

(a) All unpaved roads and disturbed areas in the project and linear construction sites shall be watered until sufficiently wet to comply with the dust mitigation objectives of AQ-C4. The frequency of watering can be reduced or eliminated during periods of precipitation.

(b) The main access and egress routes to and from the SSU6 main construction site for construction employees and delivery trucks shall be paved prior to the initiation of construction. All internal power plant roads shall be paved as early as possible. Construction employees and delivery drivers shall use paved roads to access and leave the main construction site.

(c) No vehicle shall exceed 10 miles per hour within the construction site.

(d) The construction site entrances shall be posted with visible speed limit signs.

(e) All vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

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

(g) No construction vehicles can enter the construction site except through the treated entrance roadways. Gravel pads shall be installed at all access points to prevent tracking of mud on to public roadways.

(h) Construction areas adjacent to and above grade from any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan to prevent run-off to the roadway.

(i) All paved roads within the construction site shall be swept twice daily.

(j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept twice daily. The use of dry rotary brushes is expressly prohibited except where preceded or accompanied by sufficient wetting to limit the visible dust emissions. Use of blower devices is expressly forbidden.

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

(l) All vehicles that are used to transport solid bulk material and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard. Bedliners shall be used in bottom-dumping haul vehicles.

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

(o) Diesel Fired Engines

(1) All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur~~, as soon as it is available at a terminal that by road is no more than 35 miles from the project site~~.

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

(3) All large construction diesel engines and drill rig engines, which have a rating of 50 hp or more shall meet, at a minimum, the Tier ~~1~~*4* CARB/USEPA certified standards for off-road equipment unless certified by the on-site AQCMM that a certified engine is not available for a particular item of equipment. In the event a Tier ~~1~~*4* CARB/USEPA certified engine is not available for any off-road engine larger than 50 hp, that engine shall be equipped with a catalyzed diesel particulate filter (soot filter), unless certified by engine manufacturers or the on-site AQCMM that the use of such soot filters is not practical for the specific engine type. For the purposes of this condition, a Tier ~~1~~*4* diesel engine is "not available" or the use of such soot filters is "not practical' if the AQCMM in applying recognized industry practice certifies that:

- The Tier ~~1~~*4* diesel engine is not available. For purposes of this condition, "not available" means that a Tier ~~1~~*4* diesel engine certified by either CARB or USEPA is: (i) not in existence at any location for use by the project owner at or near the time project construction commences; (ii) in existence but the construction equipment is intended to be on-site for ten (10) days or less or (iii) not available for a particular piece of equipment.

- Despite the project owner's best efforts, use of the soot filter is not practical. For the purposes of this condition, "not practical" means any of the following: (i) the use of the soot filter is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance and/or reduced power output due to an excessive increase in backpressure; (ii) the soot filter is causing or is reasonably expected to cause significant engine damage; (iii) the soot filter is causing or is reasonably expected to cause a significant risk to workers or the public; (iv) the construction equipment is intended to be on-site for ten (10) days or less or (v) other good cause approved by the CPM.

(p) The construction mitigation measures shall include necessary fugitive dust control methods required to maintain compliance with District Rule 800. Where there are similar measures the more stringent requirement shall apply. Where there is an actual conflict between these measures and a substantive control measure requirement of Rule 800, the Rule 800 requirement shall apply.

(q) For backfilling during earthmoving operations, water backfill material or apply dust palliative to maintain material moisture or to form a crust when not actively handling; cover or enclose backfill material when not actively handling; if required mix backfill soil with water prior to moving; dedicate water truck or large hose to backfilling equipment and apply water as needed; water to form a crust on soil immediately following backfilling; empty loader bucket slowly; minimize drop height from loader bucket. *The Applicant will be exempted from this condition as it applies to the placement of (earth) structural fill material to the extent that addition of water to soil would prohibit the attainment of desired engineering characteristics.*

(r) During clearing and grubbing, pre-wet surface soils where equipment will be operated; stabilize surface soil with dust palliative unless immediate construction is to continue; and use water or dust palliative to form a crust on soil immediately following clearing/grubbing.

(s) While clearing forms, use single stage pours where allowed; use water spray, sweeping and/or industrial shop vacuum to clear forms; and avoid use of high pressure air to blow soil and debris from the form.

(t) During cut and fill activities, pre-water with sprinklers or wobblers to allow time for penetration; pre-water with water trucks or water pulls to allow time for penetration.

(u) Post a publicly visible sign with the telephone number to contact regarding dust complaints. The Project Owner shall respond and take corrective action with 24 hours.

(v) Building pads should be laid as soon as possible after grading. ~~unless seeding or soil binders are used~~. *In lieu of this, the Applicant will employ the measures delineated in AQC-3(p), above.*

(w) The project owner shall require that well drilling and maintenance personnel observe reduced travel speed requirements on unpaved roadways that are under the control of CEOE and shall enforce this requirement.

Observations of visual dust plumes in excess of the dust mitigation objectives of AQ-C4 ~~would~~ *may* indicate that the existing mitigation measures are not resulting in effective mitigation. The AQCMM shall implement the following procedures for additional mitigation measures if the AQCMM determines that the existing mitigation measures are not resulting in effective mitigation:

I. The AQCMM shall direct more aggressive application of the existing mitigation methods within 15 minutes of making such a determination.

II. The AQCMM shall direct implementation of additional methods of dust suppression if step a) specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

III. The AQCMM shall direct a temporary shutdown of the source of the emissions if step II, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not be restarted until the implemented dust control mitigation is effective or, due to changed conditions, unnecessary. The owner/operator may appeal to the CPM any directive from the AQCMM to shutdown a source, provided that the shutdown shall go into effect within one hour of the original determination unless overruled by the CPM before that time.

Verification: In the MCR, the project owner shall provide the CPM a copy of the construction mitigation report and any diesel fuel purchase records, which clearly demonstrates compliance with condition AQ-C3.

AQ-C4 No construction activities are allowed to cause any visible plumes which have the potential to leave the project site, are in excess of 200 feet beyond the centerline of the construction of linear facilities, or are within 100 feet upwind of any regularly occupied structures not owned by the project owner.

Verification: The on-site AQCMM shall conduct a visible emission evaluation at the construction site fence line, or 200 feet from the center of construction activities at the linear facility, or adjacent to occupied structures each time he/she sees excessive fugitive dust from the construction or linear facility site. The records of the visible emission evaluations shall be maintained at the construction site and shall be provided to the CPM on the monthly construction report.

AQ-C5 The project owner shall submit to the CPM for review and approval any modification proposed by either the project owner or issuing agency to any project air permit.

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

AQ-C6 The project owner shall submit to the CPM and Air Pollution Control Officer (APCO) Quarterly Operations Reports, no later than 30 days following the end of each calendar quarter, that include Operations and emissions information as necessary to demonstrate compliance with all operating Conditions of Certification. The Quarterly Operations Report will specifically note or highlight incidents of noncompliance.

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

AQ-C7 All diesel-fueled engines used in the operation and maintenance of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur~~, as soon as it is available at a terminal that by road is no more than 35 miles from the plant site~~.

Verification: The project owner shall maintain records of fuel purchases, or other, records indicating the fuel sulfur content of the diesel fuel being used at the site and shall make them available for inspection on request by the CPM.

~~**AQ-C8** In addition to a LO-CAT system abating H_2S in the process, the project owner shall install a polishing system that uses a solid bed H_2S removal scavenger system.~~

~~**Verification:** Prior to initial commissioning the owner/operator shall provide design drawings of the polishing system to the District and the CEC CPM.~~ [A different H_2S abatement system will be used.]

~~**AQ-C9** As a means to decrease maximum impacts below the California ambient H_2S standard during transient conditions, the project owner shall move the four vent tanks to the emergency relief tank (ERT) location. The ERTs shall be removed from the project equipment, and the relocated vent tanks will be called vent relief tanks (VRTs). The steam routed to the VRTs will be a mix of SP, LP and HP steams. The VRT stack heights shall be 80-feet in height above grade level.~~

~~**Verification:** Prior to initiation of construction the owner/operator shall provide design layout drawings of the vent relief tanks and stacks, or other suitable proof of the stack height, to the District and the CEC CPM.~~

AQ-C10 As a means to decrease maximum impacts below the California ambient H_2S standard during well flow tests, the project owner shall limit the brine flow rate to 0.8 million pounds per hour during normal well flow testing for both the production wells and injection wells. In the event that large amounts of drilling mud are present in the well during test flow, brine flow rate may be temporarily increased up to 1.2 million pounds per hour.

Verification: A summary of brine flow rates during normal well flow testing for both production wells and injection wells shall be included in each Quarterly Operations Report or other means approved by the CPM, quarterly PM10 emission estimates for the SSU6 plant to demonstrate that the annual operational emissions are no more than 13.71 tons/year on a rolling 12-month basis.

AQC-11 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly PM10 emission estimates for the SSU6 plants to demonstrate that the annual operational emissions are ~~no more than 13.71 tons/year on a rolling 12-month basis~~ *in compliance with the Permits to Operate issued in association with this project.*

Verification: The project owner/operator shall provide the CPM with a proposed PM10 emission estimation methodology within 30 days of the start of commercial operations and shall provide the PM10 emissions estimates in the Quarterly Operations Report.

AQ-C12 The project owner shall provide through chemical monitoring and mass balance, or other means approved by the CPM, quarterly ammonia emission estimates for the SSU6 plant.

Verification: The project owner/operator shall provide the CPM with a proposed ammonia emission estimation methodology within 30 days of the start of commercial operations and shall provide the SSU6 ammonia emissions estimates in the Quarterly Operations Report.

AQ-C13 The project owner shall provide an Ammonia Control Technology and Alternative Water Source Report to the CEC on advances in ammonia control technologies and availability of new alternative cooling water sources.

Verification: The Ammonia Control Technology and Alternative Water Source Report shall be submitted to the CPM by December 15th of the calendar year that is three years after the completion of the initial commissioning of the plant, and update it every five years thereafter.

~~**AQ-C14** The emissions of PM10 from the Cooling Towers shall not exceed 2.91 lbs/hr, and the drift eliminator shall be designed to limit drift to no more than 0.0005% of the circulating water flow.~~

~~**Verification:** The project owner shall provide copies of the cooling tower specifications and a vendor warranty of the drift efficiency to the CPM 60 days prior to cooling tower equipment delivery on-site.~~

AQ-C15 Compliance with the Cooling Towers PM10 emission limit shall be determined by circulating water sample analysis by independent laboratory within 60 days of commercial operation and quarterly thereafter.

Verification: The results and field data collected from cooling tower blowdown water samples analysis shall be submitted to the CPM as part of the Quarterly Operations Reports.

DISTRICT CONDITIONS

Commissioning Period Conditions

The following Conditions AQ-1 through AQ-3 shall apply during commissioning period only.

AQ-1 At least 60 days before commissioning, the project owner shall submit a Commissioning Plan. *This plan and its associated requirements will apply to each of the Salton Sea Unit 6 plants unless the Project Owner is otherwise notified by the CPM.* The Plan shall include the following:

~~1. A public noticing of the commissioning.~~

~~2~~*1*. An H2S monitoring ~~and mitigation~~ program during the commissioning period.

2. An evaluation of available mitigation measures to control emissions of H_2S during commissioning activities.

3. ~~An updated scheduling time for all start-up events as proposed in AIR QUALITY Table 20 Plant Commissioning Schedule.~~ *A tentative schedule for all commissioning activities by plant.*

4. Reporting of all monitoring and commissioning events.

Verification: At least sixty days prior to the commissioning period, the project owner/operator shall submit a Commissioning Plan to the District and the CPM. The plan shall include an H_2S monitoring *plan* and mitigation *measures deemed economically and technologically feasible*, a schedule for all start-up events, public noticing and reporting requirements. *If necessary, the CPM and District shall provide written comment within 30 calendar days of receipt of the Commissioning Plan. The project owner shall if necessary, within 30 days of receipt of written comment from the CMP and District, furnish written response to the aforementioned comments. Notwithstanding the forgoing, neither the CMP nor the District shall unreasonably withhold approval of the Commissioning Plan from the Project Owner.* Prior to commissioning, the project owner shall provide documentation of public noticing to the District and the CPM.

AQ-2 The Commissioning Plan may be revised if found necessary by the CPM or APCD.

Verification: The project owner shall submit the Commissioning Plan and any updates of the Plan to the District and CPM for review and approval prior to the commissioning period.

AQ-3 The Commissioning Plan must be approved by the CEC and APCD before commissioning can commence.

Verification: The project owner shall submit the Commissioning Plan and any updates or revisions of the Plan to the District and CPM for review and approval prior to the commissioning period. *If necessary, the CPM and District shall provide written comment within 30 calendar days of receipt of the Commissioning Plan. The project owner shall if necessary, within 30 days of receipt of written comment from the CMP and District, furnish written response to the aforementioned comments. Notwithstanding the forgoing, neither the CMP nor the District shall unreasonably withhold approval of the Commissioning Plan from the Project Owner.*

SS Unit 6 Operations Specifications and Permit Limitations Compliance

AQ-4 The facility shall be constructed to operate in *substantial* compliance with the project description, and operating parameters ~~of the Application for Determination ff Compliance and AFC Application dated July 2002~~*delineated in the Amendment Petition*, except as may be modified by more stringent requirements of law or these conditions. Non-compliance with any condition(s) or emission specification of this Permit shall be considered a violation and subject to fines and or imprisonment. This Permit does not authorize the emissions of air contaminants in excess of those allowed by USEPA (Title 40 of the Code of Federal Regulation), the State of California Division 26, Part 4, Chapter 3 of the Health and Safety Code, or the APCD (Rules and Regulations). This permit cannot be considered permission to violate applicable existing laws, regulations, rules or statutes of other governmental agencies.

Verification: The project owner shall demonstrate compliance status in the Quarterly Operations Reports.

Emission Offsets

~~**AQ-5** The project owner shall provide, ***before*** the construction, placement or testing of any emission source(s), offsets in tons listed per source or sources listed below in TABLE A: Offsets may be in the form of ERCs (Emission Reduction Credits) owned by certified ERC holders registered with the Imperial County Air Pollution ERC Agricultural or Stationary Bank. ERCs must be transacted and validated through the APCD. New well drilling will not coincide with any other stationary emissions source for the entire project that will trigger offsets for other pollutants (other than NOx and PM10) greater than 137 lbs/day threshold. The actual calculated emissions per source has been multiplied by the ratio 1.2 to 1 to comply with offsetting ratio requirements of Rule 207 for permanent stationary sources and 1 to 1 for temporary sources.~~

~~**TABLE A**~~

~~**Sources**~~	~~**Offset Amount**~~	~~**Offset Source**~~
~~SS Unit 6 (21.1 tpy) x 1.2 + temporary emissions (0.9 tpy) x 1~~	~~26.21 tons H_2S~~	~~Leathers LP 38 Mwe Geothermal Power Plant (70 tons/yr H2S uncontrolled) control with Biofilters, sparging or APCD approved system~~
~~Well Flow Testing (temporary)~~	~~5.00 tons H_2S~~ ~~29.8 tons PM10~~	~~H_2S from Leathers LP emissions control.~~ ~~PM10 from ERC Stationary or Ag bank~~
~~SS Unit 6 pm10 (permanent) (Mitigation agreement July 24, 2003)~~	~~19.6 tons PM10~~	~~ERC Stationary or Ag bank~~
~~Commissioning (temporary)~~	~~8.7 tons H_2S~~ ~~5.63 tons PM10~~	~~H_2S from Leathers LP emissions control.~~ ~~PM10 from ERC Stationary or Ag bank~~

~~**Verification:** The project owner/operator must submit all H_2S ERC documentation to the District and the CPM prior to the start of construction. At least 30 days prior to project commissioning, the project owner shall identify and surrender the permanent and commissioning operations PM10 ERCs to the District in~~

~~the amount shown above and shall provide the CPM with documentation of the ERC surrender. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire permanent offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn secession ERCs being used to offset the project's PM10 emissions prior to each calendar or operational year, as required by the District. The project owner shall identify and surrender the well flow testing PM10 ERCs to the District as required in the District permit.~~

On or Before a Permit to Operate for ~~Unit 6~~ Can Be Issued

~~**AQ-6** The project owner shall install and have in operation a biofilter system, sparging system, or other APCD approved system at the Leathers LLC power plant capable of reducing 25.3 tons/yr (5.77 lbs/hr) of H2S at all times.~~

~~**Verification:** The project owner/operator shall make arrangements for periodic inspections of the Leathers LLC power plant by representatives of the District, CARB, USEPA and CEC.~~

~~**AQ-7** The total emissions rate of Leathers LLC H2S shall not exceed 17.03 lbs/hr after the installation of the bio-filtrations system.~~

~~**Verification:** The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.~~

~~**AQ-8** The project owner shall obtain PM10 offsets in the total amount of 19.6 tons PM10 per operating year. Offsets may be obtained through the APCD's Stationary Source and/or Agricultural Burning Emission Reduction Credits (ERCs) Bank list registered with the APCD. The Project owner shall have ERC Certificates in their possession totaling a minimum of 19.6 tons PM10 at all times during the operation of SS Unit 6. The Project owner shall surrender 19.6 tons PM10 ERC certificate(s) to the APCD prior to initial startup and annually thereafter.~~

~~**Verification:** At least 30 days prior to project commissioning, the project owner shall identify and surrender PM10 ERCs in the amount shown above. Until such time as the project owner has committed traditional stationary source ERCs to cover the entire offset burden, the project owner shall annually provide to the CPM and the District the agricultural burn cessation ERCs being used to offset the project's PM10 emissions prior to each calendar or operational year, as required by the District.~~

~~**AQ-9** The Leather's LLC Permit to Operate # 1927E H2S emission rate shall be revised to reflect **AQ-7** above.~~

~~**Verification:** The project owner/operator shall maintain the latest version of the Leathers' LLC Permit to Operate on site for the duration of the SS Unit 6 operating lifetime, or until H2S offsets from a different source have been obtained, and shall be provided to District or CPM upon request.~~ [May no longer be appropriate].

Standby Internal Combustion Engines

~~**AQ-10** Temporary or permanent internal combustion engines for this project shall not exceed the engine emissions specifications listed for this project. Upon proper notice and findings by the APCO, the project~~

~~owner shall replace or modify IC engines or apply the use of secondary emissions control measures as directed by the APCO.~~

~~**Verification:** The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.~~

AQ-11 Stationary Standby IC *Generator* Engines shall be limited to operate not more than ~~100~~ *20* hours per year for maintenance *and testing* purposes. *Stationary Standby IC Fire Water Pump Engine shall be limited to operate not more than 50 hours per year for maintenance and testing purposes.*

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-12 All IC Engines shall be equipped with diesel flow and hour meters.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-13 The IC engines shall not discharge into the atmosphere any visible emissions (which is 20% opacity or greater) other than visible water vapor, for a period or periods aggregating more than three minutes in any one hour.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-14 The project owner shall maintain logs on the premises showing hours of operation and routine repairs of the engines.

Verification: The project owner shall make the logs available for inspection by representatives of the District, CARB, USEPA and CEC.

Well Drilling

AQ-15 The project owner shall submit to the APCD fuel usage and hours of operation records.

Verification: The project owner/operator shall submit fuel usage and hours of operation to the District and CPM no later than 30 days after completion of well drilling.

Geothermal Power Plant Startups

AQ-16 Upon plant startups, the project owner shall

- Notify APCD of the time duration of the anticipated startup.
- Vent high pressure steam to condenser as soon as technically feasible during startup.

Verification: The project owner/operator shall notify the District and CPM seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup. The project owner/operator shall notify the District and CPM within three (3) days after completion of a startup. The project owner/operator shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

Geothermal Power Plant Emissions Standards

AQ-17 Under normal operations, the Project owner shall not exceed a plant wide total emission rate of the following:

Hydrogen sulfide (NCG +CT Offgassing ~~+ DWH~~)	6.48 lbs/hr
Hydrogen sulfide (NCG +CT Offgassing ~~+ DWH~~)	4.81 lbs/hr over a 24 hour average
Hazardous organics (NCG +CT Offgassing ~~+ DWH~~)	0.180 lbs/hr over a 24 hour average
NCG = exhaust form H2S abatement system CT Offgassing = cooling tower offgassing ~~DWH = Dilution Water Heater Stacks~~	

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Geothermal Steam Venting Emissions Standards

AQ-18 Noncondensible gases from the high pressure steam shall be directed to the ~~hydrogen sulfide abatement and carbon absorption~~ *RTO and associated scrubber* units at all times*, except during periods of commissioning, startup, shutdown, or malfunction.*

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

AQ-19 Emissions of uncontrolled ~~standard and low pressure~~ noncondensible *gases* shall be calculated from most recent source tests *where practical*. *In lieu of this, the project owner may use operating data from operating geothermal plants provided that these data are reviewed and approved for said use by the CPM and APCD.*

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

Monitoring

AQ-20 The project owner shall install and maintain in good working order an APCD approved continuous ~~H_2S in-stack~~ *temperature* monitor *in the oxidation chamber of the abatement equipment* ~~and flow gas meter at the H_2S control system exhaust~~. The ~~flow gas meter and in-stack~~ *temperature* monitor shall meet all specification, calibration, accuracy and quality assurance checks as set forth by the manufacturer. The monitor shall be equipped with a data logger capable of recording the continuous *temperature in the oxidation chamber*.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and CEC.

AQ-21 The project owner shall submit to the APCD an approved performance test protocol.

Testing shall not be conducted without prior APCD approval.

Verification: Thirty (30) days prior to performance testing the owner/operator shall provide a written test and emissions calculation protocol for District and CPM review and approval. The approved protocol shall be in place when written notice for the initial performance tests is submitted. Written notice of the performance test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such performance tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-22 The project owner shall establish and submit an approved monitoring protocol and method(s) for monitoring and calculating cooling tower (offgassing) H_2S offgassing and benzene emissions from carbon absorption unit.

Verification: Thirty (30) days prior to initial commissioning the project owner shall submit a monitoring protocol and method(s) for monitoring and calculating cooling tower H_2S offgassing and benzene emissions from carbon absorption unit for District and CPM review and approval. The approved monitoring protocol shall be in place prior to the end of the initial commissioning period.

AQ-23 Unless waived by the APCO, the project owner shall perform annual source testing at (1) the ~~LOCAT/Solid bed H_2S scavenger unit/Carbon adsorption~~ *RTO scrubber* exhaust for H_2S and Benzene emissions + total speciated organic emissions+ total speciated metals; *and* (2) at the cooling tower cells exhaust for H2S and ammonia and benzene emissions+ total speciated organic emissions+ total speciated metals~~, and (3) the Dilution Water Heater (DWH) exhaust emissions for H2S and benzene emissions+ total speciated organic emissions+ total speciated metals and total PM10~~.

Verification: The annual source test report shall be submitted to the District and CPM as part of the Quarterly Operations Reports. Each annual source test report shall either include the results of the initial compliance test and supplemental source tests for the current year or document the date and results of the last such tests.

AQ-24 Source tests shall be conducted at no less than 85% power capacity of the plant.

Verification: The project owner/operator shall submit records of compliance as part of the Quarterly Operations Reports.

AQ-25 The project owner shall provide the necessary scaffolding and access for source testing.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.

~~**AQ-26** In-stack monitoring equipment shall be available for inspection by the APCD at all times.~~

~~**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.~~

~~**AQ-27** The project owner shall measure and submit to the APCD monthly, in an approved format, the H_2S concentrations from the continuous H_2S monitor and benzene concentrations from the carbon absorption Unit(s).~~

~~**Verification:** The data required in this Condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.~~

~~**AQ-28** The project owner shall submit to the APCD the H_2S concentration (ppmv) and H_2S mass flow (lb/hr) measured at the non-condensable gas line before the abatement on a monthly basis. The project owner shall measure the efficiency of the cooling tower oxidizer boxes by measuring the flow rate and H_2S concentration of the condensate inlet and the H_2S outlet of the oxidizer boxes on a weekly basis and; the project owner shall measure the pH and temperature of the condensate at the inlet of the oxidizer boxes on a weekly basis. All sampling and analysis shall be performed on the same day. The project owner shall source test all cooling tower shrouds annually.~~

~~**Verification:** The data required in this condition shall be submitted to the APCD monthly and shall be provided to the CPM in the Quarterly Operations Reports.~~

~~**Ambient H_2S Monitoring**~~

~~**AQ-29** The project owner shall, with the cooperation of APCD and CARB, install and support an approved ambient H_2S monitor and supporting equipment at an Ambient Air Quality Station located near Salton Sea Geothermal area. The monitor shall meet all specification, calibration, accuracy and quality assurance check as set forth by the manufacturer. The monitor shall be equipped with a data logger capable of recording the continuous H_2S concentrations in PPB/PPMV.~~

~~**Verification:** The project owner shall make the monitoring site available for inspection by representatives of the District, CARB, USEPA and CEC, and shall make the monitoring data available to the CPM in hardcopy or electronic format upon request.~~

~~**AQ-30** The monitor shall be in full operation no later than flow testing of the first production well for the SS Unit 6 project.~~

~~**Verification:** The project owner shall make the monitoring site available for inspection by representatives of the District, CARB, USEPA and CEC. The project owner shall inform the CPM within 15 days after the ambient monitoring site becomes operational.~~

Reporting Requirements

AQ-31 The project owner shall notify the APCD before plant startups.

Verification: The project owner/operator shall notify the District and the CPM at least seven (7) days prior to an anticipated startup, including both the estimated time and duration of the startup.

AQ-32 The project owner shall notify the APCD at least 48 hours before any official source tests. All official tests shall be witnessed by an APCD official.

Verification: The project owner/operator shall notify the District and the CPM at least 48 hours prior to any official source test. The project owner/operator shall provide to the CPM the name of the APCD official who witnessed the source test in the source test report required under condition **AQ-33**.

AQ-33 The project owner shall submit source test results to the APCD no later than 30 days after the initial performance test. All source tests after the performance test shall be submitted no later than February 28th of the subsequent year for the preceding year results.

Verification: Copies of the required source tests shall be submitted to the CPM and the District simultaneously by the schedule required in this condition.

~~**AQ-34** The project owner shall submit to the APCD monthly, the benzene mole concentrations, mass rate (lbs/hr) and total NCG gas flow rate (SCFM and lbs/hr) from the carbon absorption units no later than 15 days the subsequent month for the preceding month and; the project owner shall submit to the APCD monthly, the continuous H_2S concentration (PPMv) and Mass (lbs/hr) no later than 15 days the subsequent month for the preceding month.~~

~~**Verification:** The APCD required monthly concentration and flow data shall be provided to the CPM in the Quarterly Operations Reports.~~

AQ-35 The project owner shall submit annual fuel consumption and hours of operation of diesel standby equipment no later than February 28th of each year for the subsequent year use.

Verification: The project owner/operator shall submit to the CPM the annual fuel consumption and hours of operation of diesel standby equipment in the Quarterly Operations Report for each fourth quarter.

AQ-36 The project owner shall notify the APCD of all emissions exceedances and breakdowns within 24 hours of the occurrences.

Verification: The project owner/operator shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM and the APCO as part of the Quarterly Operations Reports.

~~**Control and Monitoring Equipment Maintenance**~~

~~**AQ-37** The H_2S and carbon absorption control, and drift eliminators and or other future control devices and monitoring equipments shall be maintained in good working and operating at its maximum control efficiency level specified in accordance to the operating instructions.~~

~~**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.~~

~~**AQ-38** The Project owner shall keep a sufficient supply of catalyst, reagents and carbon for immediate system replenishment.~~

~~**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, USEPA and CEC.~~

5.2.8 References

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