UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

DOCKET
07-AFC-1
DATE JUN 0 4 2008
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June 4, 2008

Jon B. Roberts
City Manager
City of Victorville
14343 Civic Drive
P.O. Box 5001
Victorville, CA 92393-5001

Subject: Proposed Victorville II Prevention of Significant Deterioration Permit

Dear Mr. Roberts:

We have enclosed a proposed Prevention of Significant Deterioration (PSD) permit in response to your application for a United States Environmental Protection Agency Prevention of Significant Deterioration (PSD) permit (40 CFR 52.21). You have requested approval to construct a 563 MW natural gas fired combined cycle power plant in Victorville, California.

Our review of the information submitted indicates that PSD applies to the following pollutants:

Pollutant	Allowable Emission Rate (tons/year)
Carbon Monoxide (CO)	254.2
Oxides of Nitrogen (NO_x)	108.4
Total Particulate Matter (PM)	124.5
Particulate Matter less than 10 micrometers in diameter (PM_{10}), as a surrogate for $PM_{2.5}$	120.9

We have reviewed your May 4, 2007 PSD application and June 22, 2007 PSD application amendment against the review criteria established by the PSD regulations, as explained in our statement of basis and ambient air quality impact report (enclosed). EPA has concluded that the project will not cause, or contribute to, a violation of any National Ambient Air Quality Standard based on that information. We have also concluded that the project use Best Available Control Technology. EPA is proposing to approve the project subject to the enclosed conditions.

A public notice on Friday, June 6, 2008 in the Victorville Daily Press and on the EPA Region 9 website will announce the proposed project, EPA's proposed permit, and the public comment period for the proposed permit. Comments on this proposed action may be submitted to the EPA Region 9 Office, Attn: Anita Lee (AIR-3), until July 7, 2008. Should there be a significant amount of public comment with respect to the proposed action, or a specific request, EPA may hold a public hearing.

If EPA receives comments on the proposed approval, we must respond to those comments in writing by the time of our final permit action. The final permit, if granted, will be effective thirty (30) days after its receipt by the City of Victorville, unless:

1. Review is requested under 40 CFR 124.19.

2. No comments request a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

Thank you for your cooperation during this process. For questions concerning the technical review of your application, please contact Anita Lee at (415) 972-3958 or lee.anita@epa.gov.

Sincerely,

Gerardo C. Rios
Chief, Air Permits Office

cc: Allan DeSalvio, MDAQMD (via email)
John Kessler, CEC (via email)
Sara Head, ENSR (via email)
Tom Barnett, Inland Energy (via email)
Jon B. Roberts, City Manager, City of Victorville (via email)

Enclosures (2)

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION IX

STATEMENT OF BASIS AND AMBIENT AIR QUALITY IMPACT REPORT

For a Clean Air Act
Prevention of Significant Deterioration Permit

Victorville 2 Hybrid Power Project
PSD Permit Number SE 07-02

June 2008

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PROPOSED PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
VICTORVILLE II HYBRID POWER PROJECT
Statement of Basis and Ambient Air Quality Impact Report
(PSD Permit SE 07-02)

Table of Contents

Acronyms & Abbreviations

Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
Agency	U.S. Environmental Protection Agency
AQMD	Air Quality Management District
b_{ext}	Light extinction coefficient
BACT	Best Available Control Technology
BTU	British thermal units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CTG	Combustion Gas Turbine
GE	General Electric
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FWS	U.S. Fish and Wildlife Service
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
MMBTU	Million British thermal units
MW	Megawatts of electrical power
NAAQS	National Ambient Air Quality Standards
NO	Nitrogen oxide or nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of Nitrogen ($NO + NO_2$)
NP	National Park
NSPS	New Source Performance Standards, 40 CFR Part 60
NSR	New Source Review
PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 micrometers (μm) in diameter
PM_{10}	Particulate Matter less than 10 micrometers (μm) in diameter
PPMVD	Parts per Million by Volume, on a Dry basis
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RBLC	U.S. EPA RACT/BACT/LAER Information Clearinghouse
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
WA	Wilderness Area

Proposed Prevention of Significant Deterioration (PSD) Permit Statement of Basis and Ambient Air Quality Impact Report

VICTORVILLE 2 HYBRID POWER PROJECT

Executive Summary

The City of Victorville has applied for an approval to construct a new power plant that will generate 563 megawatts (MW) of net electricity using natural gas and solar energy. The power plant will be located in the town of Victorville in San Bernardino County, California. The proposed Prevention of Significant Deterioration (PSD) permit is consistent with the requirements of the PSD program for the following reasons:

- The proposed permit requires the Best Available Control Technology (BACT) for Nitrogen Oxides (NO_2), Carbon Monoxide (CO), Total Particulate Matter (PM), and Particulate Matter under 10 micrometers (PM_{10}) as a surrogate for Particulate Matter under 2.5 micrometers (μm) in diameter ($PM_{2.5}$);

- The proposed emission limits will protect the National Ambient Air Quality Standards (NAAQS) for NO_2, CO, and PM_{10}, as a surrogate for $PM_{2.5}$. There is no NAAQS set for Total Particulate Matter (PM);

- The facility will not adversely impact soils and vegetation, or air quality, visibility, and deposition in Class I areas, which are parks or wilderness areas given special protection under the Clean Air Act;

- After consultation the U.S. Fish and Wildlife Service under section 7 of the Endangered Species Act, the proposed project will not jeopardize the federally threatened desert tortoise, and will not adversely affect the federally endangered least Bell's vireo or the southwestern willow flycatcher.

1. Purpose of this Document

This document serves as the Statement of Basis and Ambient Air Quality Impact Report for the proposed Prevention of Significant Deterioration (PSD) permit for the City of Victorville – Victorville 2 Hybrid Power Project. This document describes the legal and factual basis for the proposed permit, including requirements under the PSD regulations at Title 40 of the Code of Federal Regulations (CFR) §52.21. This document also serves as the fact sheet to meet the requirements of 40 CFR Part 124.7 and 124.8.

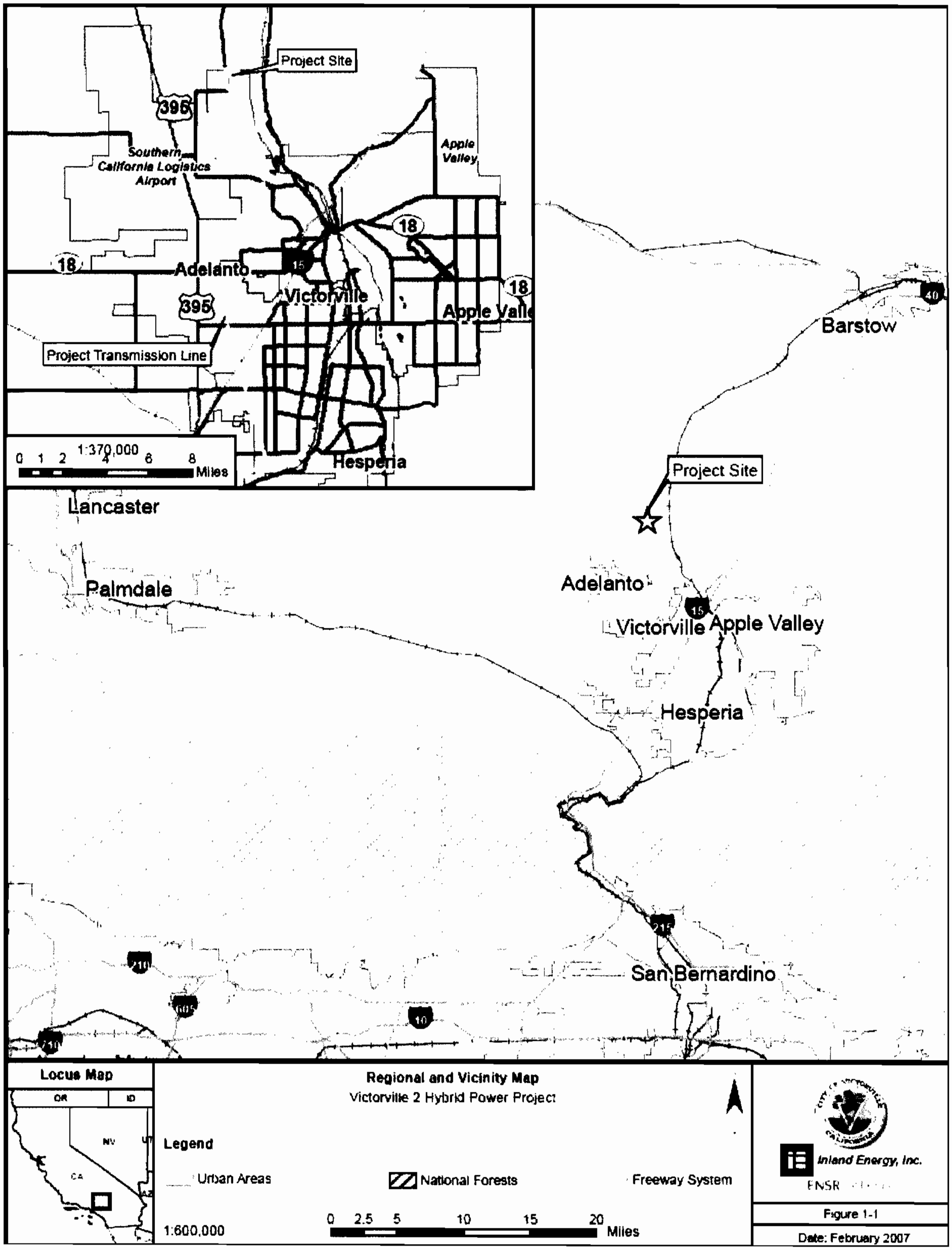
2. Applicant

City of Victorville
14343 Civic Drive
P.O. Box 5001
Victorville, CA 92395-5001

3. Project Location

The proposed location for the Victorville 2 Hybrid Power Project is in the city of Victorville, San Bernardino County, California. The site is approximately 3.5 miles east of Highway 395, and approximately 0.5 mile west of the Mojave River. The city of Victorville is located within the Mojave Desert Air Quality Management District

The map on the following page shows the approximate location of the proposed Victorville 2 Hybrid Power Project.


Project Site
395
Southern California Logistics Airport
Apple Valley
18
Adelanto
15
Victorville
Apple Valle
Project Transmission Line
1:370,000
0 1 2 4 6 8
Miles
Hesperia
Barstow
40
Project Site
Lancaster
Palmdale
Adelanto
Victorville
Apple Valley
Hesperia
215
210
605
10
San Bernardino
Locus Map
OR
ID
NV
UT
CA
AZ
Regional and Vicinity Map
Victorville 2 Hybrid Power Project
Legend
Urban Areas
National Forests
Freeway System
1:600,000
0 2.5 5 10 15 20
Miles
Inland Energy, Inc.
ENSR
Figure 1-1
Date: February 2007

4. Project Description

The City of Victorville has applied for approval to construct the Victorville 2 Hybrid Power Project to produce 563 megawatts (MW, nominal) net electrical output from a hybrid of natural gas-fired combined cycle generating equipment integrated with solar thermal components.

Electricity will be generated by the combustion turbine generators when the combustion of natural gas turns the turbine blades. The spinning blades will drive an electric generator with the potential to generate up to 154 megawatts (MW) of electricity from each turbine.

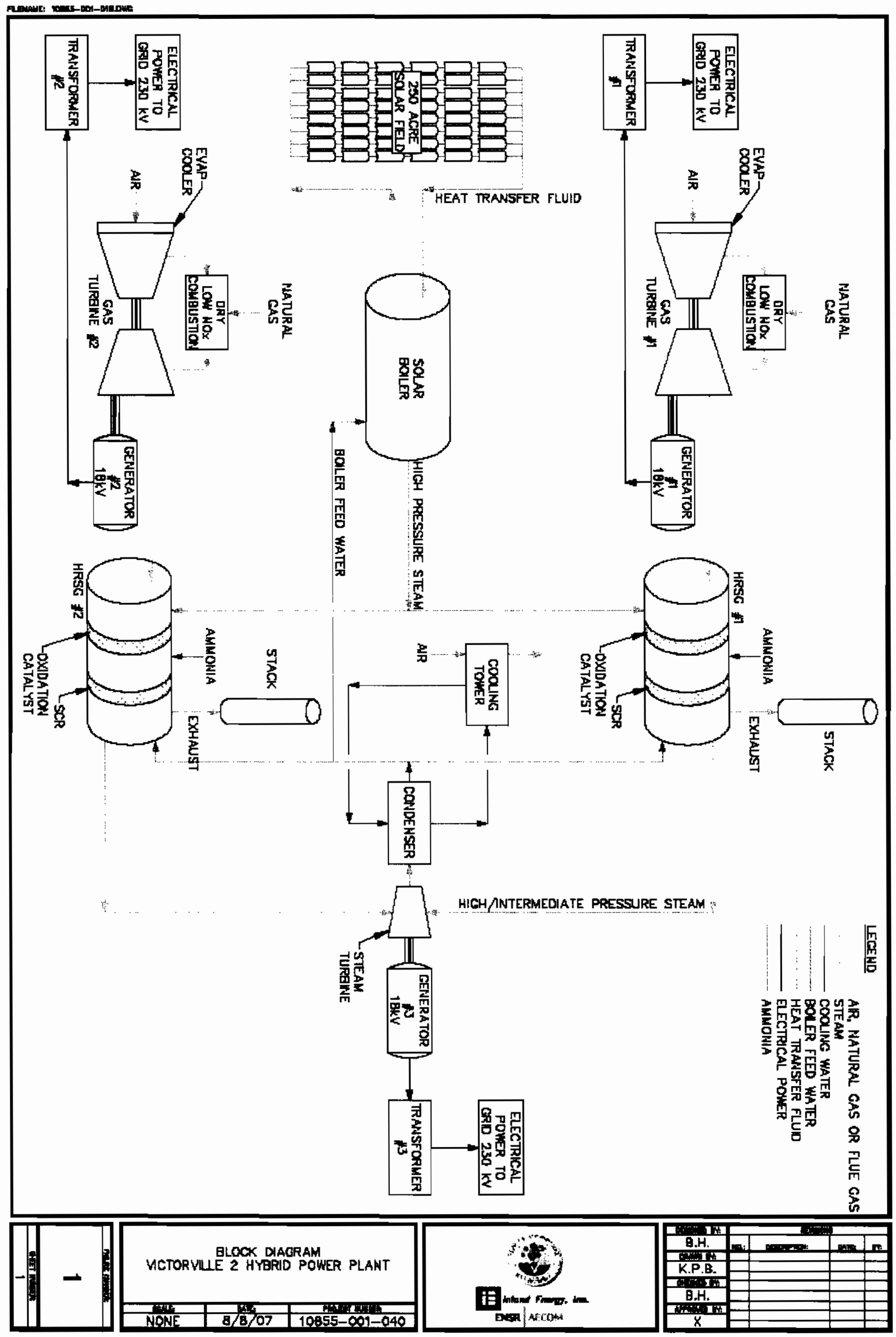
The facility will be operated in combined-cycle mode because each turbine will connect to a dedicated heat recovery steam generator (HRSG), where hot combustion exhaust gas will flow through a heat exchanger to generate steam. The facility will be equipped with duct burners firing natural gas to increase steam output from the HRSG during periods of peak demand.

The hybrid plant design will include a 250 acre solar thermal array of parabolic troughs that concentrate sunlight to heat an oil-based transfer fluid. The heat transfer fluid will be circulated to a boiler to supply steam directly to the HRSG to increase electrical generation from the steam turbine. The fluid will then be recirculated to the solar arrays.

The steam generated from HRSG will drive a 268 MW steam turbine. On sunny days, the solar array is capable of providing 50 MW of the total electrical generation from the steam turbine. Net power plant output, after subtracting electricity used on-site, will be 563 MW.

Exhaust gas exiting the steam turbine will enter a condenser. Cooling water circulating through the condenser will condense the steam into water, which will be circulated back to the HRSG. The condenser cooling water will then flow through a mechanical draft wet cooling tower, where the remaining heat will be dissipated to the atmosphere, and small quantities of dissolved solids will become airborne as particulate matter.

The diagram on the following page shows a simplified diagram of the proposed Victorville 2 Hybrid Power Project.



FILENAME: 10855-001-040.DWG
ELECTRICAL POWER TO GRID 230 kV
TRANSFORMER #1
TRANSFORMER #2
TRANSFORMER #3
250 ACRE SOLAR FIELD
HEAT TRANSFER FLUID
EVAP-COOLER
AIR
NATURAL GAS
DRY LOW NOx COMBUSTION
GAS TURBINE #1
GAS TURBINE #2
SOLAR BOILER
GENERATOR #1 18kV
GENERATOR #2 18kV
GENERATOR #3 18kV
HIGH PRESSURE STEAM
BOILER FEED WATER
HRSG #1
HRSG #2
AMMONIA
OXIDATION CATALYST
SCR
EXHAUST
STACK
COOLING TOWER
CONDENSER
HIGH/INTERMEDIATE PRESSURE STEAM
STEAM TURBINE
LEGEND
AIR, NATURAL GAS OR FLUE GAS
STEAM
COOLING WATER
BOILER FEED WATER
HEAT TRANSFER FLUID
ELECTRICAL POWER
AMMONIA
BLOCK DIAGRAM
VICTORVILLE 2 HYBRID POWER PLANT
NONE
8/8/07
10855-001-040
1
B.H.
K.P.B.
B.H.
X
Inland Energy, Inc.
ENSR | AECOM

Air Pollution Control

The Victorville 2 Hybrid Power Project will use Selective Catalytic Reduction (SCR) to reduce NO_x emissions from the combustion turbine generators. Diluted ammonia vapor will be injected into the exhaust gas before it reaches the SCR catalyst located in each of the two HRSGs. The catalysts facilitate reaction of the ammonia with NO_x to create atmospheric nitrogen (N_2) and water.

Victorville 2 will use an oxidation catalyst to reduce emissions of carbon monoxide and volatile organic compounds. Although carbon monoxide is regulated in this proposed PSD permit, volatile organic compounds will be regulated by a New Source Review permit issued by the Mojave Desert AQMD, as explained in Section 6 below.

Power Plant Start-up

In a typical combined cycle gas turbine power plant, components of the steam cycle cannot withstand rapid temperature changes, limiting how fast the steam turbine may be started. The "rapid start" design of this project is expected to reduce the time required for steam cycle start-up in half. This is important to air quality for two reasons. First, the exhaust gas temperature when the steam cycle is not operating is higher than the design temperature window for the SCR and oxidation catalysts. Secondly, the plant will generate more electricity for the amount of fuel burned when the hot gas turbine exhaust is used to power the steam generator in combined cycle. Therefore, the rapid start technology will produce more electricity and less air pollution.

The applicant describes the "Rapid Start Process" as follows[1]:

> "The "Rapid Start Process" (RSP) offered by General Electric Power Systems (GE), the supplier of the Project's combustion equipment, allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit combined stresses in the high pressure steam drum of the HRSG due to the exhaust temperature of the CTGs. The new GE design eliminates this restriction by modifying the steam drum design. Additional equipment to support the RSP includes an auxiliary boiler supplying a sealing steam header to allow startup of the steam turbine to follow shortly after the gas turbines."

For more detailed description of the facility design, please see Section II of Victorville II's Application for Certification (AFC) to the California Energy Commission[2].

Permitted Equipment

[1] Application for Certification to the California Energy Commission, Project Description p. 2-6

[2] http://www.energy.ca.gov/sitingcases/victorville2/documents/index.html

Table 1 lists the equipment that will be regulated by this PSD permit:

Table 1: Equipment List

Two natural gas-fired GE 7FA Rapid Start Process combustion turbine generators (CTG) with Heat Recovery Steam Generators (HRSG)	• Rated at 154 MW output each, with a maximum fuel input of 1,736 MMBtu/hr (HHV) each • Equipped with natural gas duct burners, rated at 424.3 MMBtu/hr (HHV) for each turbine system • Equipped with selective catalytic reduction system to reduce nitrogen oxides, and oxidation catalyst to reduce carbon monoxide
Auxiliary Heater	• 40 MMbtu/hr (HHV) with ultra low-NO_x burner
Auxiliary Boiler	• 35 MMbtu/hr (HHV) with ultra low-NO_x burner
Emergency Diesel-fired Internal Combustion (IC) Engine	• 2000 KW (2,683 hp) • California Air Resources Board Tier 2 emission standards
Emergency Diesel-fired IC Firewater Pump Engine	• 135 KW (182 hp) • California Air Resources Board Tier 3 emission standards
Cooling Tower	• 130,000 gallons per minute maximum circulation rate

5. Emissions from the Proposed Project

This chapter describes what pollutants are covered by the PSD program in this area, the PSD applicability thresholds, and our conclusion that NO_2, CO, PM, and PM_{10} as a surrogate for $PM_{2.5}$, will be regulated by the permit.

The Clean Air Act contains two preconstruction permitting programs. First, the Prevention of Significant Deterioration program is intended to protect air quality in "attainment areas"[3], which are areas that meet the National Ambient Air Quality Standards (NAAQS). The U.S. EPA is responsible for issuing PSD permits pollutants in attainment with the NAAQS in the Mojave Desert Air Quality Management District (Mojave Desert AQMD).

Second, the Nonattainment New Source Review program applies in areas where pollutant concentrations exceed the NAAQS ("nonattainment areas"). The Mojave Desert AQMD implements the nonattainment NSR program for facilities emitting nonattainment pollutants, and their precursors (e.g., volatile organic compounds and nitrogen oxides are precursors to ambient ozone). Pollutants that are nonattainment with the NAAQS will be

[3] PSD also applies to pollutants where the status of the area is uncertain (unclassified), which is not relevant for this project.

regulated in an NSR permit issued by the Mojave Desert AQMD.

Table 2: National Ambient Air Quality Standard Attainment Status for Mojave Desert AQMD

Pollutant	Attainment Status	Permit Program
Nitrogen Dioxide (NO_2)	Attainment	PSD
Oxides of Sulfur (SO_x)	Attainment	PSD
Carbon Monoxide (CO)	Attainment	PSD
Particulate Matter (PM)	n/a[4]	PSD
Particulate Matter under 2.5 micrometers diameter ($PM_{2.5}$)[5]	Attainment	PSD
Particulate matter under 10 micrometers diameter (PM_{10})	Nonattainment	NSR
Ozone	Nonattainment[6]	NSR

The PSD program (40 CFR 52.21) applies to "major" new sources of attainment pollutants. A fossil fuel-fired steam electric plant with a heat input capacity of 250 MMBtu/hr or greater, such as this facility, that emits or has the potential to emit (PTE) 100 tons per year (tpy) or more of any pollutant regulated under the Clean Air Act[7], is defined as a "major source."

6. Applicability of the Prevention of Significant Deterioration Regulations

The estimated emissions in Table 3 shows that the facility will be a major source for NO_x, CO, PM, and $PM_{2.5}$. The annual emission data in Table 3 (based on allowable operation up to 8760 hours per year) are based on the applicant's maximum expected emissions, including emissions from startup and shutdown cycles. The applicant assumes that all emissions of PM_{10} are of diameter less than 2.5 microns (i.e. $PM_{2.5}$), which is a conservative estimate, as some particulate emissions may fall in the size fraction between

[4] There is no national ambient air quality standard (NAAQS) for PM. However, in addition to other pollutants for which no NAAQS have been set, PM is listed as a regulated pollutant with a defined applicability threshold under the PSD regulations (40 CFR 52.21).
[5] Although $PM_{2.5}$ is subject to the PSD program and PM_{10} is subject to NA NSR program, EPA currently uses PM_{10} as a surrogate for $PM_{2.5}$ until appropriate test methods for $PM_{2.5}$ are developed.
[6] Because NO_x is also a precursor to ozone in this area, it will also be regulated by a separate District ozone non-attainment New Source Review permit in addition to this PSD permit.
[7] Other types of "source categories" are subject to either the same 100 tpy threshold, or else a 250 tpy threshold.

2.5 and 10 micrometers. Therefore, EPA determines that the use of PM_{10} as a surrogate for $PM_{2.5}$ is appropriate given the nature of the emissions source and the current lack of emission factors for $PM_{2.5}$.

Once a source is considered major for a PSD pollutants, PSD also applies to any other regulated pollutant that is emitted in a significant amount. The data in Table 3 show that emissions of oxides of sulfur (SO_x) will be less than the major source threshold and less than the significant emission rate. Therefore, PSD does not apply for SO_x. Estimated emissions from each emission unit of the PSD-regulated pollutants are listed in Table 4.

Table 3: Estimated Emissions and PSD Applicability

Pollutant	Estimated Annual Emissions (tons/year)	Major Source Threshold (tons/year)	Significant Emission Rate (tons/year)	Does PSD apply?
CO	254.2	100	100	Yes
NO_2	108.4	100	40	Yes
PM	124.5	100	25	Yes
PM_{10}, surrogate for $PM_{2.5}$	120.9	100	15	Yes
SO_x	8.3	100	40	No

Table 4: Estimated Emissions of PSD-regulated pollutants by Emission Unit

	CO	NO_x	PM	PM_{10}, as surrogate for $PM_{2.5}$
Total Facility	**254.2 tpy**	**108.4 tpy**	**124.5 tpy**	**120.9 tpy**
CTG+HRSG (2)	252.7	107.4	117.12	117.12
Auxiliary Heater	0.74	0.22	0.15	0.15
Auxiliary Boiler	0.33	0.10	0.065	0.065
Emergency Diesel Engine	0.39	0.67	0.02	0.02
Emergency Diesel Firewater Pump	0.03	0.03	0.002	0.002
Cooling Tower	n/a	n/a	7.13	3.6

7. Best Available Control Technology

This chapter describes the Best Available Control Technology (BACT) for the control of NO_x, CO, PM, and $PM_{2.5}$ emissions from this facility. Section 169(3) of the Clean Air Act defines BACT as follows:

> "The term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (NSPS) or 112 (NESHAPS) of the Clean Air Act."

In accordance with 40 CFR 52.21(j), a new major stationary source is required to apply BACT for each regulated NSR pollutant that it would have the potential to emit (PTE) in significant amounts. BACT is defined as "an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act ... which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such source." BACT must be at least as stringent as any applicable New Source Performance Standards (NSPS) under 40 CFR Part 60 or National Emission Standard for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 61. EPA outlines the process it will use to do this case-by-case analysis (referred to as "top-down" BACT analysis) in a June 13, 1989 memorandum. The top-down BACT analysis is a well established procedure that the Environmental Appeals Board (EAB) has consistently followed in adjudicating PSD permit appeals. See, e.g., In re Knauf, 8 E.A.D. 121, 129-31 (EAB 1999); In re Maui Electric, 8 E.A.D. 1, 5-6 (EAB 1998).

In brief, the top-down process requires that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent technology. That technology is established as BACT unless it is demonstrated that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable for the case at hand. If the most stringent technology is eliminated, then the next most stringent option is evaluated until BACT is determined. The top-down BACT analysis is a case-by-case exercise for the particular source under evaluation. In summary, the five steps involved in a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

2. Eliminate technically infeasible technology options;

3. Rank remaining control technologies by control effectiveness;

4. Evaluate the most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and

5. Select BACT, which will be the most stringent technology not rejected based on technical, energy, environmental, and economic considerations.

BACT is required for NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) for the following emission units: the two combustion turbine generators, the 40 MMBtu/hr auxiliary heater, the 35 MMBtu/hr auxiliary boiler, the two diesel-fired internal combustion engines, and the cooling tower. Table 5 lists the BACT determinations for NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) from the combustion turbines, heaters, boilers, and engines, and PM and PM_{10} (as a surrogate for $PM_{2.5}$) from the cooling tower.

We are setting BACT limits using PM_{10} as a surrogate for $PM_{2.5}$ BACT limits because we currently lack adequate $PM_{2.5}$ emission factors and data to set source-specific $PM_{2.5}$

BACT levels for this equipment[8]. For instance, the US EPA RACT/BACT/LAER Clearinghouse (RBLC) listings since January 1, 2004 include the PM_{10} emission rates for combined cycle gas turbines, but not $PM_{2.5}$ emission rates. While we lack sufficient data to set source-specific BACT limits on $PM_{2.5}$, we do have information showing that PM_{10} is an appropriate surrogate that correlates well with the $PM_{2.5}$ emissions from natural gas combustion at this type of facility.[9] Using PM_{10} as a surrogate for $PM_{2.5}$ will not affect our control technology determination, because there are no particulate add-on controls available for PM, PM_{10}, or $PM_{2.5}$ emissions from the types of combustion equipment covered by this permit[10].

[8] This approach is consistent with our October 23, 1997 transition memo guidelines, which authorize limits for PM_{10} as a surrogate for limits on $PM_{2.5}$ during the transition period lasting until final PSD $PM_{2.5}$ regulations are issued due to the lack of $PM_{2.5}$ emissions factors. See EPA memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, "Interim Implementation of New Source Review for PM2.5," October 23, 1997, available at http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/pm25.pdf.

[9] Based US EPA's AP-42 section 1.4, page 3.8.

[10] US EPA's evaluation of BACT for the emergence use IC Engines is based on comparable engines restricted to low usage, as noted in the relevant section of the BACT analysis.

Table 5: Summary of BACT Limits and Requirements for Testing and Monitoring[11]

	NO_x	CO	PM and PM_{10} (surrogate for $PM_{2.5}$)	Restrictions on Usage
2 Combustion Turbines (each, no duct burning)	• 11.55 lb/hr • 1-hr average • 2.0 ppmvd, 15% O_2 • CEMS • Annual Performance Testing • Quarterly and Annual RATA for CEMs	• 7.65 lb/hr • 1-hr average • 2.0 ppmvd, 15% O_2 • CEMS • Annual Performance Testing • Quarterly and Annual RATA for CEMs	• 12.0 lb/hr • 12-mo. average • PUC natural gas • Sulfur < 0.2 gr/100 scf • Monthly natural gas fuel testing • Annual Performance Testing	n/a
2 Combustion Turbines (each, with duct burning)	• 14.6 lb/hr • 1-hr average • 2.0 ppmvd, 15% O_2	• 13.35 lb/hr • 1-hr average • 3.0 ppmvd,15% O_2	• 18.0 lb/hr • 12-mo average • PUC natural gas • Sulfur < 0.2 gr/100 scf	• Total duct burning (D3 & D4) < 2000 hrs/yr
Heater 40 MMBtu/hr (HHV) **Boiler** 35 MMBtu/hr (HHV)	• 9 ppm, 3% O_2 • 1-hr average • Annual Performance Testing	• 50 ppm, 3% O_2 • 1-hr average • Annual Performance Testing	• Sulfur < 0.2 gr/100 scf • PUC natural gas • Monthly natural gas fuel testing	• 1000 hr/yr • Non-resettable elapsed time meter • 500 hr/yr • Non-resettable elapsed time meter
IC engine 2000 KW (2,683 hp) **Firewater Pump** 135 KW (182 hp)	• 6.0 g/KW-hr, (4.5 g/hp-hr)[12] • Annual Performance Testing • 3.8 g/KW-hr, (2.8 g/hp-hr)[11] • Annual Performance Testing	• 3.5 g/KW-hr, (2.6 g/hp-hr) • Annual Performance Testing	• 0.20 g/KW-hr, (0.15 g/hp-hr) • Exclusive use of ultra low sulfur fuel, not to exceed 15 ppmvd sulfur • Fuel Supplier Certification • Annual Performance Testing	• 50 hr/year • Non-resettable elapsed time meter • 50 hr/year • As required for fire testing • Non-resettable elapsed time meter
Cooling tower 130,000 gpm	n/a	n/a	• 1.6 lb/hr (total PM) • < 0.0005% drift • < 5000 ppm total dissolved solids • Weekly water quality testing	n/a

[11] Victorville 2 must keep all records of all testing, fuel use, and fuel testing requirements for a period of five (5) years and must report excess emissions to EPA on a quarterly basis.
[12] Emission standards for NO_x in the New Source Performance Standard for stationary compression ignition internal combustion engines (40 CFR Part 60 Subpart IIII) and the California Tier Emission Standards are based on the sum of NO_x and non-methane hydrocarbons (NMHC). For the NO_x emission limits, the applicant assumes NMHC + NO_x emissions from the engine are 95% NO_x.

7.1. *BACT for Natural Gas Combustion Turbine Generators*

7.1.1. Oxides of Nitrogen

NO_x is formed when nitrogen and oxygen are present at high temperatures in the combustion process. The applicant has proposed a 2.0 parts per million by volume on a dry basis (ppmvd) NO_x limit, averaged over a 1-hour time period, excluding startups and shutdowns. BACT for periods of startup and shutdown are discussed in Section 7.1.4. EPA agrees that 2.0 ppmvd NO_x represents BACT, as we are not aware of any similar operating facility with a lower permit limit. The Selective Catalytic Reduction (SCR) and dry low-NO_x burners proposed by the applicant are well established control technologies for this type of source. Excess ammonia emissions from the SCR (ammonia slip) will be limited to 5 ppmvd.

7.1.2. Carbon Monoxide

Carbon monoxide (CO) occurs due to incomplete combustion of natural gas in the gas turbine, and in the duct burners when they are operated. The applicant has proposed to install an oxidation catalyst to control CO. The application states that the facility will achieve 2.0 ppmvd CO over a 1-hour averaging period when it does not use duct burning, excluding startups and shutdowns. BACT for periods of startup and shutdown are discussed in Section 7.1.4. We believe 2.0 ppmvd CO is the lowest emission rate that has been included in a permit for a facility of this type. The application also requests a slightly higher 3.0 ppmvd CO emission rate when duct burning is used, due to higher CO concentrations from the duct burners. While the facilities we reviewed generally have higher emission rates, there are some facilities with a 2.0 ppmvd CO limit that applies at all times. We believe that the combination of emission rates proposed by the applicant falls within the stricter end of the range of emission rates acceptable as BACT for CO, based on our review of data in the RBLC. Replacing duct burning with solar energy, when available, will reduce the amount of time that the facility would use duct burning with the higher CO emission rates.

7.1.3. Particulate Matter (PM) and Fine Particulate ($PM_{2.5}$)

Particulate emissions from the gas turbine trains result from fuel sulfur, inert trace contaminants, and incomplete combustion of hydrocarbons. We do not believe that any add-on particulate emission controls have been demonstrated in practice for this type of source. Thus, the proposed permit limits the sulfur content of the fuel to no more than 0.2 grains per 100 dry standard cubic feet as BACT, which would limit sulfate particulate emissions.

We are proposing to limit particulate emissions (PM and PM_{10}) to 12 lb/hr from each turbine without duct burner firing, and 18 lb/hr with duct burner firing. As noted earlier, using PM_{10} as a surrogate for $PM_{2.5}$ does not affect the emission controls selected as BACT.

7.1.3. Startup and Shutdown BACT limits

For periods of startup and shutdown, the Applicant has proposed emissions limitations on NO_x and CO, and startup and shutdown duration limits. In a typical combined cycle gas turbine power plant, components of the steam cycle cannot withstand rapid temperature changes, resulting in startup durations that typically exceed 4 hours. The applicant has proposed use of the GE Rapid Start Process which allows the steam-side components to be started more quickly due to modifications of the HRSG steam drum and use of an auxiliary boiler. In addition to duration and emission limits, BACT also includes work practice standards that require the SCR to be operated, and ammonia injected into the SCR, once exhaust temperatures reach the minimum operating temperature of the SCR, 450 °F, or as otherwise specified by the manufacturer.

Table 6 lists the startup and shutdown BACT emission and duration limits per combustion turbine generator. We believe the combination of work practice standards for SCR operation, and the Rapid Start Process allowing startup and shutdown duration limits, and NO_x and CO emission limits, that are lower than limits for traditional combined cycle power plants, are acceptable as BACT. Futhermore, the total number of startup and shutdown events will be limited according to the values used in the Applicant's emissions calculations.

Table 6: BACT Limits (per CTG) for Startup and Shutdown

	NO_x	CO	Duration	Annual Event Limit
Cold Startup	• 52.4 lb/hr • 96 lb/event • 4.8 tpy	• 224 lb/hr • 410 lb/event • 20.5 tpy	1.8 hr/event	50 events/yr
Warm and Hot Startup	• 30 lb/hr • 40 lb/event • 10.4 tpy	• 247 lb/hr • 329 lb/event • 85.5 tpy	1.3 hr/event	260 events/yr
Shutdown	• 114 lb/hr • 57 lb/event • 17.7 tpy	• 674 lb/hr • 337 lb/event • 104.5 tpy	0.5 hr/event	310 events/yr

7.2. BACT for Auxiliary Boiler and Heater

The permit applicant has proposed a BACT emission rate of 9 ppmvd NO_x for both the 35 MMBtu auxiliary boiler (used to reduce start-up times) and the 40 MMBtu/hr auxiliary heater (used occasionally to prevent the solar array heat transfer fluid from freezing). The applicant notes that no lower limit is listed in the South Coast database for similar units, and we have determined that this emissions rate is also the lowest achieved by any similar source included among recent US EPA RBLC database entries[13]. Therefore, we have determined that 9 ppmvd NO_x represents BACT for these units.

In the April 2007 PSD application, the permit applicant proposed emission limits of 100 ppmvd CO for these auxiliary units. The applicant states that a NO_x /CO trade-off exists for low-NO_x combustion technology chosen to limit NO_x emissions rates, and that 100 ppmvd CO has been accepted by South Coast AQMD as BACT for these types of units. We have reviewed the US EPA RBLC database for the 12 comparable units with determinations for CO from 2005 to the present, and found the lowest emission rate required for any such unit was 50 ppmvd CO. Consequently, in a March 24, 2008 letter to EPA, the permit applicant agreed that 50 ppmvd CO, combined with 9 ppmvd NO_x limits, for the size and duty cycle of the auxiliary boiler and heater were commercially available and represented BACT. CO emission estimates from the auxiliary boiler and heater were based on the applicant's 100 ppmvd CO BACT limit. Because the applicant has subsequently agreed to meet a 50 ppmvd CO limit, the emission estimates provided in Table 4 are 50% of the emissions originally submitted by the applicant.

We are not aware of any post-combustion emission controls that are feasible for the small amount of fine particulate emissions expected from small boilers and heaters, and we have set BACT for fine particulates based on the combustion of natural gas. The proposed permit also limits the sulfur content of the fuel to pipeline quality natural gas, which would limit any sulfate particulate emissions.

7.3. BACT for Emergency Internal Combustion Engines

The 2000 KW (2,683 hp) emergency diesel-fired internal combustion (IC) engine, will meet the California Tier 2 performance standards for NO_x, CO, and PM_{10}, and will be limited to less than 50 hours per year of use. The 135 KW (182 hp) emergency firewater pump will meet the California Tier 3 emission standards for NO_x, CO, and PM_{10}, and will also be limited to less than 50 hours per year of use. Non-emergency use of the firewater pump will be limited to the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems".

[13] Our search covered 2005, 2006, and 2007 up to the most recent entry dated May 3, 2007, for units listed under process type 13.1.

We are not aware of any similar, low-use emergency IC engines with lower emission rates, and we have included the applicant's proposed emission limits in the proposed permit. While some IC engines in the South Coast BACT database have used an add-on air pollution control device, none are operated as infrequently as these units (maximum of 50 hours per year). Therefore, EPA determines that these performance standards without add-on control devices represent BACT for these units. We are also limiting fuel use to ultra-low sulfur fuel with a maximum sulfur content of the fuel of 15 ppmvd in order to limit the fine particulate emissions from the engines. As noted earlier, setting limits in terms of PM_{10} as a surrogate for PM and $PM_{2.5}$ does not affect the stringency of our BACT evaluation.

7.4. BACT for Cooling Towers

The applicant proposed wet cooling towers that use reclaimed water from the Victor Valley Wastewater Reclamation Authority water treatment facility. The wet cooling towers would be equipped with high efficiency mist eliminators limiting drift to 0.0005% as BACT for this project. Mist eliminators greatly reduce the amount of cooling tower water that becomes airborne along with small quantities of dissolved solids. Wet cooling towers equipped with mist eliminators are the most effective control technology for controlling PM and $PM_{2.5}$ from wet cooling towers and are BACT.

Either wet or dry cooling towers can be used at combined cycle natural gas-fired power plants. Dry cooling in lieu of wet cooling may be selected to reduce water consumption (see Colusa Generating Station, Colusa County, CA[14]). The City of Victorville will reduce the associated environmental impacts of water consumption by using reclaimed waste water. Dry cooling reduces water usage and avoids the direct PM and $PM_{2.5}$ emissions associated with wet cooling, however, dry cooling also results in reduced power plant efficiency. The applicant estimated that the use of a dry cooling system would reduce the efficiency of the Victorville 2 Power Plant by 6.5% due to back pressure on the steam turbine and parasitic load. To achieve the same power output accounting for the loss of efficiency from dry cooling, the combustion of additional natural gas would be required and would increase emissions of all combustion pollutants from the gas turbine, including $PM/PM_{2.5}$, NO_x, and CO, by 6.5%. A 6.5% increase in emissions from the gas turbines represents an additional 7.6 tpy of $PM/PM_{2.5}$. Thus, because wet and dry cooling have associated advantages and disadvantages, and because the applicant will use reclaimed wastewater for wet cooling and high efficiency mist eliminators to reduce direct $PM/PM_{2.5}$ emissions from the wet cooling system to 7.2 tpy (0.0005% of possible emissions without the high efficiency drift eliminators), we have concluded that dry cooling, while technologically feasible, is not mandatory as BACT for this project.

[14] http://www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436

8. Air Quality Impacts

The PSD regulations require an examination of the impacts of the proposed project on ambient air quality. The applicant must determine, using air quality models, whether emissions of the PSD-regulated air pollutants would cause a violation of (1) the National Ambient Air Quality Standards (NAAQS), or (2) the applicable PSD increments (explained below in Section 8.4). This chapter includes a discussion of the background data, air quality modeling, and our conclusion that the project will not adversely affect air quality.

8.1. Background Ambient Air Quality and Conditions

The air quality impact analysis used three years of wind speed, direction, and temperature data collected from the Victorville Park Avenue meteorological station by the Mojave Desert Air Quality Management District from 2002-2004. Additional data on cloud cover and cloud ceiling height were obtained from National Weather Service from General William J. Fox Field in Lancaster, CA, and upper air data were obtained from Mercury Desert Rock Airport in Mercury, NV. Maximum background air quality concentrations (Table 7) were used in the NAAQS analysis.

8.2. Modeling Methodology

The applicant modeled of the facility on the NAAQS and PSD Class II increments using AERMOD in accordance with the EPA Guidelines on Air Quality Models (as incorporated in Appendix W of 40 CFR Part 51). The modeling analyses included the maximum air quality impacts during start-ups and shut-downs, as well as a variety of conditions to determine worst-case short-term air impacts. These variables included operating levels, duct firing, evaporative cooling, and use of solar energy. Representative annual average ambient temperature (77 degrees F) and emissions from maximum plant operation was used to model annual impacts.

The applicant conducted a Good Engineering Practice (GEP) stack height analysis using the EPA Building Profile Input Program (BPIP, version 04274) to evaluate the potential of building downwash. The stack parameters are described in Section 6.1, and details on the facility characteristics can be found in Tables 6-3, 4, and 5 of the PSD application.

The applicant used the "ozone-limiting" method to convert NO_x emissions to ambient NO_2 conditions based on the Guideline on Air Quality Models. The applicant assumed that 10% of the NO_x is formed as NO_2 in the combustion process, and that the conversion of the remaining NO_x is based on the available ozone concentration.

The Class I area analysis was performed using CALPUFF Version 5.754 for long range transport that required additional detailed meteorological data as explained in the Class I modeling protocol (December 2006 Class I Area Dispersion Modeling Protocol – Victorville 2 – 10855-001-040MPA). Additionally, the applicant used CALPUFF to assess PSD Class I increment consumption, regional haze, and acid deposition. For more information on the modeling methodology, please see the April 2007 PSD application, June 25, 2007 application supplement, and modeling protocol. The Class I modeling protocol was provided to the Federal Land Managers (FLMs) for the five Class I areas listed below (Section 8.4).

EPA has established Significant Impact Levels (SILs) to characterize air quality impacts. A SIL is the ambient concentration resulting from the facility's emissions, for a given pollutant and averaging period, below which the source is assumed to have an insignificant impact. For maximum modeled concentrations below the SIL, no further air quality analysis is required for the pollutant. For maximum concentrations that exceed the SIL, a cumulative modeling analysis, that incorporates the combined impact of nearby sources of air pollution, is required to determine compliance with the NAAQS and PSD increments.

8.3. National Ambient Air Quality Standards and PSD Class II Increment Consumption Analysis

The modeling results (Table 7) show that the maximum increase in ambient concentration (Maximum Project Impact) resulting from the project do not exceed the SILs set for NO_2 and CO. SILs for $PM_{2.5}$ have not yet been set by EPA. Because the modeled impacts do not exceed the SILs, the project is assumed to have an insignificant impact on air quality, however, the applicant chose to also model the impacts of the project on the NAAQS and the Class II increment.

PSD increments are limits on cumulative air quality degradation. They are set to prevent air with pollutant concentrations lower than the NAAQS from being degraded to the level of the NAAQS. PSD increments apply in addition to the NAAQS. Increments have been established for some PSD pollutants, such as NO_2, SO_2, and PM_{10}. There are currently no PSD increments set for $PM_{2.5}$, CO, ozone, and lead.

Table 7 shows that the project will not cause a violation of the NO_2, CO, or $PM_{2.5}$ NAAQS. Modeling for PM was not conducted because there is no NAAQS set for PM. Table 7 presents the project's total ambient air quality impacts based on the maximum modeled project impacts plus monitored background levels. The applicant's modeling assumes that all PM_{10} from the facility is $PM_{2.5}$. Because this is a conservative assumption, actual project impacts on $PM_{2.5}$ may be less than the result listed in Table 7.

Table 7: NAAQS and Class II Increment Compliance Results

Pollutant	Averaging Period	Background ($\mu g/m^3$)	Maximum Project Impact ($\mu g/m^3$)	Significant Impact Level (SIL) ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	Annual	41	0.3	1	25	41.3	100
$PM_{2.5}$[15]	24-hour	26	6.1	NA	NA	32	35
$PM_{2.5}$[16]	Annual	11	0.3	NA	NA	11.3	15
CO	1-hour	4,485	215.8	2000	NA	4,701	40000
CO	8-hour	2,415	31.9	500	NA	2,447	10000

8.4. Class I Analysis

8.4.1. Class I Increment Consumption Analysis

The PSD regulations contain two levels for the NO_2 increments that apply to this project: one for Class II areas (Section 8.3), and another for Class I areas. Class I areas are national or regional areas of special natural, scenic, recreational, or historic value. These areas are given special protection through stricter increments, as well as other protections discussed further in Section 9. Currently, all areas of the United States that are not designated as Class I areas are designated as Class II areas.

The following Class I areas are within 100 kilometers of the proposed project, or in the case of Joshua Tree, just outside of 100 kilometers:

- Cucamonga Wilderness Area
- Joshua Tree National Park
- San Gabriel Wilderness Area
- San Gorgonio Wilderness Area

[15] $PM_{2.5}$ project maximum modeled concentrations are assumed equal to PM_{10} values. To the extent that not all PM_{10} emissions are $PM_{2.5}$, the actual $PM_{2.5}$ impact will be less than stated here. EPA has neither promulgated nor proposed significant modeling concentrations for $PM_{2.5}$ at this time, although we do intend to propose them in the future.

[16] Same as footnote above.

- San Jacinto Wilderness Area

Table 8 shows the results from the applicant's Class I analyses. The expected impact of the project is below the Class I SILs for NO_x for all Class I areas. Because the expected project impact is below these levels, the second step of determining the cumulative impact of the project plus all increases and decreases from other sources is not required.

Table 8: PSD NO_2 Class I Increment Analysis

Class I Area	Maximum Predicted Project NO_2 Impacts (ug/m^3) – annual average	NO_2 "Significant Impact" level (ug/m^3)	Cumulative Increment Analysis Required?
Cucamonga WA	0.0033	0.1	No
Joshua Tree NP	0.0013	0.1	No
San Gabriel WA	0.0031	0.1	No
San Gorgonio WA	0.00082	0.1	No
San Jacinto WA	0.00037	0.1	No

There are no $PM_{2.5}$ increments in place currently, however, the applicant has voluntarily provided data on the project's expected maximum $PM_{2.5}$ impacts on Class I and Class II areas for informational purposes (see Tables 2 and 3 of the applicant's June 22, 2007 PSD application supplement).

8.4.2 Visibility and Deposition in Class I areas

The PSD regulations require that PSD permit applicants address potential impairment to visibility, also known as regional haze, in Class I areas. The applicant used CALPUFF to predict visibility and deposition impacts at Class I areas. Visibility impacts are assessed according to an extinction coefficient (b_{ext}) that represents the scattering of light by air pollutants that produces a hazy effect that reduces visibility. The results of the CALPUFF models are shown in Table 9 and indicate that changes in light extinction (b_{ext}), averaged over a 24-hour period, at all Class I areas are predicted to be below the 5% change significance threshold[17]. Applicants are not required to perform a cumulative effects analysis of new source growth if the visibility impact of their proposed source is less than 5%. Therefore, emissions from the facility are not expected to significantly impact regional haze and visibility in any Class I area and no analysis of cumulative visibility impacts is necessary.

Portions of the Cucamonga Wilderness Area (WA) are within 50 km of the proposed

[17] Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report dated December 2000.

facility site. Therefore, in addition to regional haze visibility analyses, the impact of the facility on visibility impairment (i.e., plume blight) in Cucamonga WA must also be assessed. The EPA VISCREEN screening model was used to estimate visibility impairment in Cucamonga WA. Effects of plume blight are assessed as changes in plume perceptibility (ΔE) and plume contrast (C_p) for sky and terrain backgrounds. The results from the VISCREEN model show that changes in plume perceptibility and plume contrast for sky and terrain backgrounds are below the criteria thresholds (see Table 6-14 of the PSD application).

Table 9: PSD NO_2 Class I Visibility and Deposition Analysis

Class I Area	Maximum Predicted % Change in b_{ext}	Significance Threshold (%)	Maximum Predicted Nitrogen Deposition – annual average (g/ha/yr)	Deposition Analysis Threshold (g/ha/yr)
Cucamonga WA	3.80	5	1.15	5
Joshua Tree NP	1.20	5	0.323	5
San Gabriel WA	3.56	5	1.38	5
San Gorgonio WA	1.98	5	0.388	5
San Jacinto WA	0.75	0.1	0.151	5

The deposition of NO_2 is another potential concern due to potential effects on soils, vegetation, and other biological resources. The results from the deposition analysis show that the maximum deposition rates are below the Class I Area Nitrogen Deposition Analysis Threshold of 0.005 kilograms per hectares per year (equivalent to 5 grams per hectare per year), so no further deposition analysis is necessary.

9. Additional Impact Analysis

In addition to assessing the ambient air quality impacts expected from a proposed new source, the PSD regulations require that EPA evaluate other potential impacts on 1) soils and vegetation; and 2) growth.

9.1 Soils and Vegetation

For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects because the secondary NAAQS are set to protect public welfare, including vegetation, crops, and animals. No harmful effects are expected from this project because the total estimated maximum ambient concentrations presented in Table 6 are below the primary NAAQS (listed in Table 6) and secondary NAAQS for NO_2 (100 $\mu g/m^3$) and $PM_{2.5}$ (35 $\mu g/m^3$ for 24-hour periods; and 15.0 $\mu g/m^3$ over an annual period). There are no secondary NAAQS for CO.

Additionally, the applicant used the EPA "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (1980) to assess the individual and cumulative impacts of the facility on sensitive vegetation and crops. The modelled impacts of NO_2 and CO emissions from the facility, individually, and in addition to the background concentrations of NO_2 and CO, are below the minimum impact level for sensitive plants (See Table 6-14 in the PSD application). Therefore, we do not expect any adverse impacts on plants, soils, and animals.

9.2. Growth

We do not expect this project to result in any significant growth. Approximately 36 permanent workers will be hired for normal operation of the power plant, and any additional industrial, commercial, or residential growth is expected to be minimal. The increased traffic resulting from the Victorville II workforce will be negligible compared to the existing traffic in the area.

10. Endangered Species

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. 1536, and its implementing regulations at 50 C.F.R. Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this PSD permitting action is subject to ESA Section 7 requirements.

Initial site surveys conducted by the applicant found desert tortoise (*Gopherus agassizii*) individuals present at the proposed power plant site. The desert tortoise is listed as a threatened species pursuant to the ESA. The applicant has prepared a Biological Assessment that includes proposed mitigation.

In a letter dated June 11, 2007, EPA initiated formal consultation under section 7 of the ESA with the FWS regarding the desert tortoise. EPA additionally requested concurrence from FWS that the project is not likely to adversely affect the bald eagle (*Haliatus leucocephalus*), the federally endangered least Bell's vireo (*Vireo bellii pusillus*), and the southwestern willow flycatcher (*Empidonax trailii extimus*).

On January 23, 2008, the FWS concluded formal consultation on the desert tortoise and issued their final Biological Opinion. FWS determined that the Victorville 2 Hybrid Power Project would not likely jeopardize the continued existence of the desert tortoise, and concurred with the EPA determination that the project is not likely to adversely affect the least Bell's vireo and the southwestern willow flycatcher. Additionally, the FWS determined that section 7 consultation for the bald eagle was no longer required because the bald eagle was removed from the list of threatened and endangered species. The City of Victorville must comply with the Reasonable and Prudent Measures (RPMs) and Terms and Conditions outlined in the final BO to minimize take of the desert tortoise during construction.

On February 25, 2008, the City of Victorville submitted an addendum to their PSD application committing to comply with all the RPMs, Terms and Conditions of the final BO. Under the PSD regulations outlining source obligations, 40 CFR 52.21(r), the City of Victorville must construct in accordance with their PSD application and with the terms of their approval to construct.

11. Clean Air Act Title IV (Acid Rain Permit) and Title V (Operating Permit)

The applicant must apply for and obtain an acid rain permit and a Title V operating permit. The applicant will apply for these permits after the facility is constructed, as these permits are not required prior to construction. The Mojave Desert AQMD has jurisdiction to issue the Acid Rain Permit and the Operating Permit for the facility.

12. Conclusion and Proposed Action

EPA is proposing to issue a PSD permit to Victorville II. We believe that the proposed project will comply with PSD requirements including the installation and operation of BACT, and will not cause or contribute to a violation of the NAAQS, or of any PSD increment. We have made this determination based on the information supplied by the applicant and our review of the analyses contained in the permit application. EPA will provide the proposed permit and this AAQIR to the public for review, and make a final decision after considering any public comments on our proposal.

VICTORVILLE II HYBRID POWER PROJECT (SE 07-02)
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
PROPOSED PERMIT CONDITIONS

PROJECT DESCRIPTION

The proposed facility is a combined-cycle power plant capable of generating up to 563 megawatts (MW, nominal) of net power. Electrical power will be generated from the combustion of natural gas in two 154 MW combustion turbine generators (CTG). Exhaust from each gas turbine will flow through a dedicated Heat Recovery Steam Generator (HRSG) to produce steam to power a shared 267 MW Steam Turbine Generator (STG). Each HRSG will be equipped with natural gas-fired duct burners to augment steam production during peaking operation. The facility will include a field of parabolic trough solar collectors to produce additional high pressure steam for the HRSG. Solar thermal energy can displace up to 50 MW of duct burning, with the same total overall capacity.

The facility is subject to the Prevention of Significant Deterioration (PSD) Program for emissions of Carbon Monoxide (CO), Nitrogen Dioxide (NO_2), Particulate Matter (PM), and Particulate Matter under 2.5 micrometers (μm) in diameter ($PM_{2.5}$).

The following devices are subject to this PSD permit:

Device ID	Description
D1	• 154 MW Combustion Turbine Generator (CTG) • Natural gas-fired GE 7FA Rapid Start Process • Vented to a dedicated Heat Recovery Steam Generator (HRSG) and a 267 MW Steam Turbine Generator (STG) shared with D2 • Emissions of NO_2 and CO controlled by Selective Catalytic Reduction (SCR) and an Oxidation Catalyst (Ox-Cat)
D2	• 154 MW Combustion Turbine Generator (CTG) • Natural gas-fired GE 7FA Rapid Start Process • Vented to a dedicated HRSG and a 267 MW STG shared with D1 • Emissions of NO_2 and CO controlled by SCR and an Ox-Cat
D3	• 424.3 MMBtu/hr (HHV) Duct Burner for D1, fired on natural gas
D4	• 424.3 MMBtu/hr (HHV) Duct Burner for D2, fired on natural gas
D5	• 40 MMBtu/hr (HHV) Auxiliary Heater with ultra low-NO_x burner
D6	• 35 MMBtu/hr (HHV) Auxiliary Boiler with ultra low -NO_x burner
D7	• 2000 KW (2,683 hp) Internal Combustion (IC) Diesel-fired Emergency Engine
D8	• 135 KW (182 hp) IC Diesel-fired Emergency Firewater Pump Engine
D9	• 130,000 gallons per minute (maximum circulation rate) Cooling Tower

I. PERMIT EXPIRATION

As provided in 40 CFR 52.21(r), this PSD Permit shall become invalid if construction:

A. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect; or

B. is discontinued for a period of 18 months or more; or

C. is not completed within a reasonable time.

II. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 9 in writing or by electronic mail of the:

A. date construction is commenced, postmarked within 30 days of such date.

B. actual date of initial startup, as defined in 40 CFR 60.2, postmarked within 15 days of such date.

C. date upon which initial performance tests will commence, in accordance with the provisions of Condition IX.H, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition IX.H.

D. date upon which initial performance evaluation of the CEMS will commence in accordance with 40 CFR 60.13(c), postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the CEMS performance test protocol required pursuant to Condition IX.G

III. FACILITY OPERATION

At all times, including periods of startup, shutdown, shakedown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating maintenance procedures and inspection of the source.

IV. MALFUNCTION REPORTING

A. Permittee shall notify EPA at R9.AEO@epa.gov within two (2) working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in emissions above the allowable emission limits stated in Section IX of this permit.

B. In addition, Permittee shall provide an additional notification to EPA in writing or electronic mail within fifteen (15) days of any such failure described under Condition IV.A. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section IX, and the methods utilized to mitigate emissions and restore normal operations.

C. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

V. RIGHT OF ENTRY

The EPA Regional Administrator, and/or an authorized representative, upon the presentation of credentials, shall be permitted:

A. to enter the premises where the source is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

B. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

C. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and

D. to sample materials and emissions from the source(s).

VI. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter, a copy of which shall be forwarded to EPA Region IX.

VII. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

VIII. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD permit, the application on which this permit is based, the Terms and Conditions of the final Biological Opinion issued on January 23, 2008 pursuant to the Section 7 Consultation with the U.S. Fish and Wildlife Service, and all other applicable federal, state, and local air quality regulations, including, but not limited to, the Standards of Performance for New Stationary Sources (40 CFR Part 60) Subparts A, Dc, KKKK, and IIII of this regulation. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

IX. SPECIAL CONDITIONS

A. Annual Facility Emission Limits

Annual emissions, in tons per year (tpy) on a 12-month rolling average basis, shall not exceed the following:

	NO_x	CO	PM	PM_{10}, surrogate for $PM_{2.5}$
Total Facility	**108.4 tpy**	**254.2 tpy**	**124.5 tpy**	**120.9 tpy**

B. Air Pollution Control Equipment and Operation

On or before the date of initial start-up of the power plant (as defined in 40 C.F.R. 60.2), and thereafter, except as noted below in section IX.D., the Permittee shall install, continuously operate, and maintain Selective Catalytic Reduction (SCR) systems for control of NO_x and oxidation catalysts for control of CO for Units D1 and D2. Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit.

C. Combustion Turbine Generator Emission Limits

1. Except as noted below under Condition IX.D, on and after the date of initial start-up, Permittee shall not discharge or cause the discharge of emissions from each combustion turbine generator (CTG) unit (D1 and D2) into the atmosphere in excess of the following:

	Emission Limit (per CTG) (no duct burning)	**Emission Limit (per CTG) (with duct burning)**
NO_2	• 11.55 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2	• 14.6 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2
CO	• 7.65 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2	• 13.35 lb/hr • 1-hr average • 3.0 ppmvd @ 15% O_2
PM and PM_{10} (as a surrogate for $PM_{2.5}$)	• 12.0 lb/hr • 12-month rolling average • PUC-quality natural gas • Sulfur content of no greater than 0.2 grains per 100 dscf	• 18.0 lb/hr • 12-month rolling average • PUC-quality natural gas • Sulfur content of no greater than 0.2 grains per 100 dscf

2. Combined hours of operation for both duct burners (D3 and D4) shall not exceed 2000 hours per 12-month rolling average. The Permittee shall ensure that the duct burners are not operated unless the associated turbine units are in operation.

D. Requirements during Gas Turbine (D1 and D2) Startup and Shutdown

1. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with all operating permit limits for two consecutive 15-minute averaging periods or the maximum time allowed for the event after ignition, whichever occurs first.

   a. A cold startup means a startup when the CTG has not been in operation during the preceding 48 hours.

b. Warm and hot start-ups include all startups that are not a cold startup.

c. Shutdown is defined as the period beginning with the lowering of equipment from normal operating load and lasting until fuel flow is completely off and combustion has ceased.

2. During startup and shutdown periods emissions from each CTG and associated HRSG unit, verified by the Continuous Emissions Monitoring System (CEMS), shall not exceed the following:

	NO_x	**CO**	**Duration**	**Annual Event Limit**
Cold Startup	52.4 lb/hr 96 lb/event	224 lb/hr 410 lb/event	1.8 hr/event	50 events/yr
Warm and Hot Startup	30 lb/hr 40 lb/event	247 lb/hr 329 lb/event	1.3 hr/event	260 events/yr
Shutdown	114 lb/hr 57 lb/event	674 lb/hr 337 lb/event	0.5 hr/event	310 events/yr

3. The Permittee must operate the CEMS during startups and shutdowns.

4. The Permittee must record the time, date, and duration of each startup and shutdown event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

5. The SCR system, including ammonia injection, shall be operated as soon as the SCR reaches an operating temperature of 550 degrees Fahrenheit.

E. Auxiliary Combustion Equipment Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge or cause the discharge of emissions from each unit into the atmosphere in excess of the following:

	NOx	CO	PM and PM_{10} (as surrogate for $PM_{2.5}$)	Restrictions on Usage
Unit D5 40 MMBtu/hr (HHV) Heater	• 9 ppmvd @ 3% O_2 • 1-hr average	• 50 ppmvd @ 3% O_2 • 1-hr average	• 0.2 grains per 100 dscf • PUC-quality natural gas	• 1000 hr/yr
Unit D6 35 MMBtu /hr (HHV) Boiler				• 500 hr/yr
Unit D7 2000 KW (2,683 hp) engine	• 6.0 g/KW-hr, (4.5 g/hp-hr)[1]	• 3.5 g/KW-hr, (2.6 g/hp-hr)	• 0.20 g/KW-hr, (0.15 g/hp-hr) • Use of ultra-low sulfur fuel, not to exceed 15 ppmvd fuel sulfur	• 50 hr/yr
Unit D8 135 KW (182 hp) firewater pump	• 3.8 g/KW-hr, (2.8 g/hp-hr)[2]			• As required for fire safety testing • Not to exceed 50 hr/yr
Unit D9 130,000 gpm Cooling Tower	n/a	n/a	• 1.6 lb/hr (as total PM) • < 0.0005% drift • < 5000 ppm total dissolved solids	n/a

F. Cooling Tower Emission Limits

1. The cooling tower drift rate shall not exceed 0.0005% with a maximum circulation rate of 130,000 gallons per minute (gpm). The maximum total dissolved solids (TDS) shall not exceed 5000 ppm.

2. The maximum hourly total PM emission rate from the cooling tower and the evaporative condenser combined shall not exceed 1.6 lb/hr.

G. Continuous Emissions Monitoring System (CEMS) for Units D1 and D2

[1] Emission standards for NO_x in the New Source Performance Standard for stationary compression ignition internal combustion engines (40 CFR Part 60 Subpart IIII) and the California Tier Emission Standards are based on the sum of NO_x and non-methane hydrocarbons (NMHC). For the NO_x emission limits, the applicant assumes NMHC + NO_x emissions from the engine are 95% NO_x.

1. At the earliest feasible opportunity before beginning commercial operation, in accordance with the recommendations of the equipment manufacturer and the construction contractor, Permittee shall install, and thereafter operate, maintain, certify, and quality-assure a continuous emission monitoring system (CEMS) for each combustion turbine generator that measures stack gas NO_x, CO, and O_2 concentrations in ppmv. The concentrations shall be corrected to 15% O_2 on a dry basis.

2. The NO_x and O_2 CEMS shall meet the applicable requirements of 40 CFR Part 60 Appendix B, Performance Specifications 2 and 3, and 40 CFR Part 60 Appendix F, Procedure 1. Alternatively, the NO_x CEMS shall meet the installation and certification requirements of 40 CFR Part 75.

3. The CO CEMS shall meet the applicable requirements of 40 CFR Part 60 Appendix B, Performance Specification 4, and 40 CFR Part 60 Appendix F, Procedure 1, except the relative accuracy specified in section 13.2 of 40 CFR Part 60 Appendix B, Performance Specification 4 shall not exceed 20 percent.

4. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute clock-hour period.

5. The CEMS shall be certified and tested in accordance with Condition IX.G.7.

6. The performance evaluation of the CEMS may either be conducted separately, as specified in 40 CFR 60.334(b)(1), or as part of the initial performance test of each emission unit. CEMS must undergo and pass initial performance specification testing on or before the date of the initial performance test.

7. CEMS shall meet the requirements of 40 CFR 60.13. Data sampling, analyzing, and recording shall also be adequate to demonstrate compliance with emission limits during startup and shutdown.

8. Not less than 90 days prior to the date of initial startup of the Facility, the Permittee shall submit to the EPA a quality assurance project plan for the certification and operation of the continuous emission monitors. Such a plan shall conform to EPA requirements contained in 40 CFR 60, Appendix F for CO, NO_x, and O_2, and 40 CFR 75 Appendix B for stack flow. The plan shall be updated and resubmitted upon request by EPA. The protocol shall specify how emissions during startups and shutdowns will be determined and calculated, including quantifying flow accurately if calculations are used.

9. The gas turbine CEMS shall be tested annually and quarterly in accordance

with the requirements of 40 CFR Part 60 Appendix F, Procedure 1. Permittee shall perform a full stack traverse during initial run of annual RATA testing of the CEMS, with testing points selected according to 40 CFR Part 60 Appendix A, Method 1.

10. Permittee shall submit a CEMS performance test protocol to the EPA no later than 30 days prior to the test date to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

11. Permittee shall furnish the EPA a written report of the results of performance tests within 60 days of completion.

12. The stack gas volumetric flow rates shall be calculated in accordance with the fuel flowmeter requirements of 40 CFR Part 75 Appendix D in combination with the appropriate parts of EPA Method 19.

13. Prior to the date of initial start-up Permittee shall install, and thereafter maintain and operate, continuous monitoring and recording systems to measure and record the following operational parameters:

    a. The ammonia injection rate of the ammonia injection system of the SCR system.

    b. Exhaust gas temperature at the inlet to the SCR reactor

H. Performance Tests

1. Stack Tests

a. Within 60 days after achieving normal operation, but not later than 180 days after the initial start-up of equipment, and annually thereafter (within 30 days of the initial performance test anniversary), Permittee shall conduct performance tests (as described in 40 CFR 60.8) as follows:

    i. NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) emissions from each gas turbine (Units D1/D3 and D2/D4),

    ii. NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) emissions the 40 MMBtu/hr heater (D5), the 35 MMBtu/hr boiler (D6),

iii. NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) emissions from the 2000 KW (2,683 hp) internal combustion engine (D7).

iv. NO_x, CO, PM, and PM_{10} (as a surrogate for $PM_{2.5}$) emissions from the 135 KW/hr firewater pump (D8) upon notification by EPA

v. PM emissions from the cooling tower (D9).

b. The annual performance tests shall be conducted in accordance with the requirements of 40 CFR Part 60, Appendix F, Procedure 1, Section 5.11.

c. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

d. Performance tests shall be conducted in accordance with the test methods set forth in 40 CFR 60.8 and 40 CFR Appendix A, as modified below. In lieu of the specified test methods, equivalent methods may be used with prior written approval from EPA:

i. EPA Methods 1-4 and 7E for NO_x emissions measured in ppmvd,

ii. EPA Methods 1-4, 7E, and 19 for NO_x emissions measured on a heat input basis,

iii. EPA Methods 1-4 and 10 for CO emissions,

iv. EPA Methods 5 and 202 for both PM and PM_{10} (as a surrogate for $PM_{2.5}$), in accordance with the test methods set forth in 40 CFR § 60.8 and 40 CFR Part 60, Appendix A. In lieu of Method 202, the Permittee may use EPA Conditional Test Methods for particulate matter: CTM-039 or CTM-040. If Method 202 is used, the test methodology must include:

a. one hour nitrogen purge
b. the alternative procedure described in section 8.1 to neutralize the sulfuric acid
c. evaporation of the last 1 ml of the inorganic fraction by air drying following evaporation of the bulk of the impinger water in a 105 °C oven as described in the first sentence of section 5.3.2.3.

v. Modified Method 306 or the Cooling Tower Institute's heated bead test method for PM emissions from the cooling tower, and

vi. the provisions of 40 CFR Part 60.8 (f).

e. The initial performance test conducted after initial startup shall use the test procedures for a 'high NO_2 emission site,' as specified in San Diego Test Method 100, to measure NO_2 emissions. The source shall be classified as either a 'low' or 'high' NO_2 emission site based on these test results. If the emission source is classified as a:

   i. 'high NO_2 emission site,' then each subsequent performance test shall use the test procedures for a 'high NO_2 emission site,' as specified in San Diego Test Method 100.

   ii. 'low NO_2 emission site,' then the test procedures for a 'high NO_2 emission site,' as specified in San Diego Test Method 100, shall be performed once every five years to verify the source's classification as a 'low NO_2 emission site.'

f. The performance test methods specified in Condition X.F.3., may be modified as follows:

   i. Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

   ii. Use the test data both to demonstrate compliance with the applicable NO_x emission limit and to provide the required reference method data for the RATA of the CEMS.

g. Upon written request and adequate justification from the Permittee, EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity.

h. For performance test purposes, sampling ports, platforms, and access shall be provided on the emission unit exhaust system in accordance with the requirements of 40 CFR 60.8(e).

i. Permittee shall furnish the EPA a written report of the results of performance tests within 60 days of completion.

2. Cooling Tower Total Dissolved Solids Testing

a. Permittee shall perform weekly tests of the blow-down water quality using a EPA approved method. The operator shall maintain a log that contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five years and shall be provided to EPA and District personnel on request.

b. Permittee shall calculate PM and PM_{10} emission rate using an EPA-approved calculation based on the TDS and water circulation rate.

c. The operator shall conduct all required cooling tower water quality tests in accordance with an EPA-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for EPA review and approval, with a copy to the District as specified in Condition XI below.

d. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators, to ensure that the TDS limits are not exceeded, and to ensure compliance with recirculation rates. This procedure is to be kept onsite and available to EPA and District personnel on request. The permittee shall promptly report any deviations from this procedure.

3. Fuel Testing

a. Permittee shall take monthly samples of the natural gas combusted. The samples shall be analyzed for sulfur content using an ASTM method. The sulfur content test results shall be retained on site pursuant to Special Conditions IX.C and IX.E for Units D1 – D6.

I. Monitoring for Auxiliary Combustion Equipment

1. Permittee shall install and maintain an operational non-resettable totalizing mass or volumetric flow meter in each fuel line for the 40 MMBtu/hr heater (Unit D5) and the 35 MMBtu /hr boiler (Unit D6).
2. Permittee shall install and maintain an operational non-resettable elapsed time meter for the 40 MMBtu/hr heater (Unit D5), the 35 MMBtu /hr boiler (Unit D6), the 2000 KW emergency use engine (Unit D7) and the 135 KW emergency-use firewater pump (Unit D8).

J. Recordkeeping and Reporting

1. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the Facility, including, but not limited to, the following: all records or reports pertaining to adjustments and/or maintenance performed on any system or device at the Facility; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition IX.E for Units D7 and D8; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

2. Permittee shall maintain CEMS records that contain the following: the occurrence and duration of any startup, shutdown, shakedown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments, maintenance, duration of any periods during which a continuous monitoring system or monitoring device is inoperative, and corresponding emission measurements.

3. Permittee shall maintain records of all source tests and monitoring and compliance information required by this permit.

4. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually. The report is due on the 30^{th} day following the end of the calendar quarter and shall include the following:

    a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;

    b. Applicable time and date of each period during which the CEMS was inoperative (monitor down-time), except for zero and span checks, and the nature of CEMS repairs or adjustments; and

    c. A negative declaration when no excess emissions occurred or when the CEMS has not been inoperative, repaired, or adjusted.

    d. Any failure to conduct any required sources testing, monitoring, or other compliance activities.

    e. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

5. Excess emissions shall be defined as any period in which the facility emissions exceed the maximum emission limits set forth in this permit.

6. A period of monitor down-time shall be any unit operating clock hour in which sufficient data are not obtained to validate the hour for NO_x, CO or O_2.

7. Excess emissions indicated by the CEM system, source testing, or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

8. All records required by this PSD Permit shall be retained for not less than five years following the date of such measurements, maintenance, and reports.

K. Shakedown Periods

The combustion turbine emission limits and requirements in Sections IX.C, IX.D, and IX.E shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The requirement of section III of this permit shall apply at all times.

X. ACROYNMS AND ABBREVIATIONS

APCD	Air Pollution Control District
ASTM	American Society for Testing and Materials
BTU	British Thermal Unit
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
CTM	Conditional Test Method
District	Mojave Desert Air Pollution Control District
(d)scf	(dry) Standard Cubic Feet
EPA	Environmental Protection Agency
g	grams
gr	grains
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
hp	Horsepower
hr	Hour
KW	Kilowatt
lbs	Pounds
MMBtu	Million British Thermal Units
MW	Megawatt
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standards
O_2	Oxygen
PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter with aerodynamic diameter less than 2.5 micrometers
PM_{10}	Particulate Matter with aerodynamic diameter less than 10 micrometers
ppmvd	Parts Per Million by Volume, Dry basis
ppmv	Parts Per Million by Volume
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RATA	Relative Accuracy Test Audit
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
STG	Steam Turbine Generator
TDS	Total Dissolved Solids
tpy	Tons Per Year
yr	Year

XI. AGENCY NOTIFICATIONS

All correspondence as required by this Approval to Construct must be forwarded to:

A. Director, Air Division (Attn: AIR-5)
EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Email: R9.AEO@epa.gov
Fax: (415) 947-3579

B. Air Pollution Control Officer
Mojave Desert Air Quality Management District
14306 Park Avenue
Victorville, CA 92392-2310

From: John Kessler
To: Docket Optical System
CC: Caryn Holmes; Matthew Layton; Tuan Ngo
Date: 6/6/2008 9:03 AM
Subject: Fwd: EPA Proposal and Request for Public Comment: Victorville 2 PSD permit

Dear Docket Staff:

Please docket this email as part of the PSD Permit files that I emailed earlier to Victorville 2 (07-AFC-1).

Thank you,

John

John S. Kessler
CEC - Project Manager
Office: 916-654-4679
Cell: 530-306-5920
Fax: 916-654-4421

>>> <Lee.Anita@epamail.epa.gov> 6/6/2008 7:54 AM >>>
The Region 9 Office of the United States Environmental Protection Agency (EPA) requests public comment on a proposed Prevention of Significant Deterioration (PSD) Permit. The permit will grant conditional approval, in accordance with the Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), to the City of Victorville to construct and operate a 563 MW (net) electric generating facility. The proposed facility, called Victorville II, would be located in Victorville, San Bernardino County, California, and consist of two GE 7FA Rapid Start Process gas turbines, two heat recovery steam generators, one steam turbine generator, a thermal solar field, a wet cooling tower, and associated equipment.

The proposed PSD permit will require the use of Best Available Control Technology to limit emissions of carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter (PM), and particulate matter less than 10 micrometers in diameter (PM10), as a surrogate for particulate matter less than 2.5 micrometers in diameter (PM2.5), to the greatest extent feasible. The emissions of other air pollutants from the proposed project will be regulated and limited by the Mojave Desert Air Quality Management District (District). Air pollution emissions from Victorville 2 will not cause or contribute to violations of any of the National Ambient Air Quality Standards (NAAQS).

The proposed permit and request for public comment was announced in the legal advertising section of the Friday June 6, 2008 edition of the Victorville Daily Press . The EPA Region 9 Air Permits website also announces the public comment period and provides a hyperlink to the docket that contains all documents in the administrative record :

http://www.epa.gov/region09/air/permit/r9-permits-issued.html#pubcomment

The Region 9 website is not yet updated with the Victorville 2 information and hyperlink to www.regulations.gov, however all posted documents are already available at www.regulations.gov website, please go to:

http://www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0406

The Region 9 website should be updated shortly.

The proposed permit conditions and the Ambient Air Quality Impact Report are document numbers 16 and 17 in the docket, under the document category "other", found at the end of the list of documents.

The administrative record may also be viewed in person, Monday through Friday from 9:00 AM to 4:00 PM, at the EPA Region 9 address below. Due to building security procedures, please call to arrange a visit 24 hours in advance. Hard copies of the administrative record can be mailed to individuals upon request.

The proposed permit and ambient air quality impact report are available to review at the following locations: Mojave Desert Air Quality Management District, 14306 Park Ave, Victorville, CA 92392, (760) 245-1661; Victorville Public Library, 15011 Circle Drive, Victorville, CA 92395, (760) 245-4222; Apple Valley Public Library, 14901 Dale Evans Parkway, Apple Valley, CA 92307, (760) 247-2022; Adelanto Public Library, 11497 Bartlett Avenue, Adelanto, CA 92301, (760) 246-5661.

Pursuant to 40 CFR 124.12, EPA has discretion to hold a Public Hearing if we determine there is a significant amount of public interest in the proposed permit. Requests for a Public Hearing must state the nature of the issues proposed to be raised in the hearing. If a Public Hearing is to be held, a public notice stating the date, time and place of the hearing will be made at least 30 days prior to the hearing. Reasonable attempt will be made to notify directly any person who has commented on this proposal of any pending Public Hearing, provided contact information has been given to the EPA contact person listed below.

All comments on the proposed permit, and requests for a Public Hearing, must be received by email or postmarked by July 7, 2008. An extension of the 30-day comment period may be granted if the request for an extension adequately explains why more time is required to prepare comments. Comments must be sent or delivered in writing to Anita Lee at the postal or email address shown below. All comments should address the proposed permit and must be received by email or postmarked by July 7, 2008.

All comments that are received will be included in the public docket without change and will be available to the public, including any personal information provided, unless the comment includes Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Information that you consider CBI or otherwise protected should be clearly identified as such and should not be submitted through e-mail. If you send e-mail directly to the EPA, your e-mail address will be automatically captured and included as part of the public comment. Please note that an e-mail or postal address must be provided with your comments if you wish to receive direct notification of EPA?s final decision regarding the permit and responses to comments submitted during the public comment period.

EPA will consider all written comments before taking final action on the PSD air permit and will send notice of the final decision to each person who submitted comments and contact information during the public comment period or requested notice of the final permit decision. EPA will respond to all substantive comments in a document accompanying the final permit decision and make the hearing proceedings available to the public.

The final decision will become effective 30 days from the date of issuance unless:

1. A later effective date is specified in the decision; or

2. The decision is appealed to the Environmental Appeals Board pursuant to 40 CFR 124.19 (any person who submits written comments on the

proposed permit or who participates in the Public Hearing may petition the Environmental Appeals Board to review any part of the permit decision within 30 days after the decision has been issued. Any person who failed to file comments and failed to participate in the public hearing on the proposed permit may petition for review by the Environmental Appeals Board only those parts of the final permit decision which are different than the proposed permit); or

3. There are no comments requesting a change to the proposed permit, in which case the final decision shall become effective immediately upon issuance.

If the proposed permit becomes final, and there is no appeal, construction of the project may commence, subject to the conditions of the permit and other applicable permit and legal requirements.

If you have questions, please contact Anita Lee at (415) 972-3958 or email at R9airpermits@epa.gov.

Please bring the foregoing notice to the attention of all those potentially interested in this matter.

Thank you,

* *
Anita Lee
ph: (415) 972-3958
fax: (415) 947-3579

US EPA, Region 9
Air Permits Office
75 Hawthorne Street (AIR-3)
San Francisco, CA 94105
* *