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July 7, 2008

Mr. Anita Lee
US EPA, Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Subject: Comments Regarding the Proposed Victorville 2 Hybrid Power Project Prevention of Significant Deterioration Permit Conditions

Dear Ms. Lee,

On behalf of the City of Victorville and Inland Energy, ENSR is submitting this letter which provides comments regarding the proposed Victorville 2 Prevention of Significant Deterioration (PSD) Permit for the Victorville 2 (VV2) Hybrid Power Project.

1) Project Name

In some places in the permit and the Statement of Basis and Ambient Air Quality Impact Report, the project is listed as the "Victorville II" project. The project does not use a Roman numeral, and should be shown as the "Victorville 2 Hybrid Power Project".

2) Annual Facility Emission Limits

Condition IX.A of the proposed PSD permit lists the project's limited annual potential particulate (PM) emissions as 124.5 ton per year (tpy) and the particulate < 10 microns (PM10) emissions as 120.9 tpy. The annual facility PM and PM10 emission limits contained in the proposed PSD permit appear to be based on information provided in the original PSD application. That application made the assumption that PM10 emissions from the cooling tower would equal 50% of the Total Dissolved Solids (TDS) / PM emissions. However, the supplement to the PSD application dated January 30, 2008, clarified that the project would assume that PM10 emissions from the cooling tower are equal to the calculated PM emissions. Therefore, the PM10 emissions listed under Condition IX.A should be revised to equal 124.5 tpy in order to be consistent with the information submitted to the EPA on January 30, 2008 and contained within the Final Determination of Compliance (FDOC) prepared by the Mojave Desert Air Quality Management District.

3) Combustion Turbine Generator Emission Limits

a. Condition IX.C.1 limits the emission rate of NO_x from each combustion turbine generator (CTG) with duct burning to 14.6 lb/hr. This emission rate is based on average temperature conditions, and the maximum rate associated with low ambient temperatures should be used for maximum hourly limits. Please revise this limit to 15.60 lb/hr which is the correct emission rate as presented in the FDOC.

b. Condition IX.C.1 limits the emission rate of CO from each CTG with duct burning to 13.35 lb/hr. Please revise this limit to 14.25 lb/hr which is the correct emission rate as presented in the FDOC.

c. Condition IX.C.1 limits the emission rate of PM and PM10 from each combustion turbine generator (CTG) (no duct burning) to 12 lb/hr as a 12-month rolling average and the CTG (with duct burning) to 18 lb/hr as a 12-month rolling average. These limits are acceptable since they represent the approximate emission rates expected from the CTGs. However, it is important to note the following items regarding the proposed PM10 emission limits:

1) The proposed PM10 emission limits are lower than the CTG manufacturer's guarantee; and

2) The use of the Rapid Start Process (RSP) in association with the CTGs is a new technology and it is uncertain what impact it may have on the overall emission rates from the CTGs.

We are not requesting a change in these limits but identifying some associated uncertainties should they need to be re-visited at a future date.

d. Condition IX.C.1 limits the emission rate of CO from each CTG (no duct burning) to 7.65 lb/hr on a 12-month rolling average. The source of this emission limit could not be identified. We believe that the correct emission rate should be 7.04 lb/hr as presented in the PSD permit application and the FDOC.

e. Condition IX.C.2 states the following: "Combined hours of operation of both duct burners (D3 and D4) shall not exceed 2,000 hours per 12-month rolling average." The language proposed in this condition is not consistent with the information provided in the PSD application. The emission calculations provided with the PSD application are based on each duct burner operating up to 2,000 hours per year. In order to maintain maximum operational flexibility, we request that condition IX.C.2 be revised to read: "Combined hours of operation of both duct burners (D3 and D4) shall not exceed 4,000 hours per 12-month rolling average."

4) Requirements during Gas Turbine (D1 and D2) Startup and Shutdown

a. Condition IX.D.2 of the proposed PSD permit limits the duration of each transient event (startup and shutdown) associated with the CTGs. The limits are presented in hours per event in the proposed draft permit. It is requested that the limits be presented in minutes per event as shown in the following table:

	Duration
Cold Startup	110 minutes/event
Warm and Hot Startup	80 minutes/event
Shutdown	30 minutes/event

b. Condition IX.D.2 of the proposed PSD permit proposes to limit the number of cold startups, warm and hot startups, and shutdowns that each CTG could perform per year. The limit on the type of each operation per year appears to have been taken from the emissions calculations submitted as part of the original PSD permit application. The number of each operation used in the emission calculations was intended only as a basis for estimating the expected transient operation emissions and should not be listed as limits on the operation of the facility. The inclusion of limits on the number of these operations should not be required for the following reasons:

1) The facility is required to operate a continuous emissions monitoring system (CEMS) during start-ups and shutdowns that will monitor the total emissions associated with these operations. Therefore the requirement for use of a CEMS and the inclusion of annual emission limits in the permit is sufficient to limit the facility's emissions;

2) The limit on the type of each operation unnecessarily limits operational flexibility. For example, if during a given year the operating conditions dictate fewer cold startups and therefore more warm or hot startups, the overall facility emissions will actually be lower than estimate contained in the emission calculation included in the permit application; and

3) Most permits for combined-cycle power plants within EPA Region IX do not contain such limits as they are an unnecessary restriction on the operation of the plant with no commensurate air quality benefit.

Therefore, it is requested that the limits on the number of cold startups, warm or hot startups, and shutdowns be removed from the proposed permit.

5) Auxiliary Combustion Equipment Emission Limits

a. Condition IX.E of the proposed PSD permit limits NO_x emissions from Unit D7 (2000 kW emergency generator) to 6.0 g/kW-hr and Unit D8 (135 kW firewater pump) to 3.8 g/kW-hr. As presented in the PSD permit application, please revise Condition IX.E for Unit D7 to reflect the applicable California Tier 2 NO_x emission limit of 6.4 g/kW-hr (4.8 g/hp-hr) and Unit D8 to reflect the applicable California Tier 3 NO_x emission limit of 4.0 g/kW-hr (3.0 g/hp-hr).

b. Condition IX.E of the proposed PSD permit for Unit D8 (firewater pump) lists Footnote 2 with the associated NOx emission limit. Footnote 2 is not included in the copy of the proposed PSD permit provided for review. Please clarify if there is a footnote intended with this permit.

c. Condition IX.E of the proposed PSD permit limits Unit D9 (Cooling Tower) to < 5000 ppm total dissolved solids (TDS). Consistent with the PSD permit application and subsequent submittals, please revise this condition to read "≤ 5,000 ppm TDS".

d. Condition IX.E of the proposed PSD permit limits use of Unit D7 (2000 kW engine) to 50 hr/yr and Unit D8 (firewater pump) to "as required for fire safety testing" and "not to exceed 50 hr/yr". We believe that these restrictions do not clearly present that there cannot be restrictions on the use of the emergency generator or the firewater pump for emergencies. To clarify this restriction, we request that the proposed language be revised to read: "Maintenance and fire safety testing shall not exceed 50 hr/yr" for both Unit D7 and Unit D8.

6) Cooling Tower Emission Limits

Condition IX.F.2 states the following: The maximum hourly total PM emission rate from the cooling tower *and the evaporative condenser* shall not exceed 1.6 lb/hr." The proposed project does not include an evaporative condenser emission unit. We request that this condition be revised to read as follows: "The maximum hourly total PM emission rate from the cooling tower shall not exceed 1.6 lb/hr."

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

a. Condition IX.G.5 states the following: “The CEMS shall be certified and tested in accordance with Condition IX.G.7. We do not understand the reason for the inclusion of this condition. We believe that Conditions IX.G.6 and IX.G.7 are adequate with regard to the certification and testing of the CEMS. Therefore, we request that condition IX.G.5 be removed from the proposed permit.

b. We request that Condition IX.G.6 be revised as follows: “The initial certification of the CEMS may either be conducted separately, or 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 certification testing on or before the date of the initial performance test.

c. Condition IX.G.9 requires that “The gas turbine CEMS shall be tested annually and quarterly in accordance with 40 CFR Part 60 Appendix F, Procedure 1.” 40 CFR Part 60 Appendix F, Procedure 1 requires that a CEMS be audited quarterly with at least one Relative Accuracy Test Audit (RATA) being completed every 4 quarters. We believe that the proposed language should be clarified by revising it to read as follows: “The gas turbine CEMS shall be audited quarterly and tested annually in accordance with 40 CFR Part 60 Appendix F, Procedure 1.

d. Condition IX.G.10 states that: “Permittee shall submit a CEMS performance test protocol to the EPA not later than 30 days prior to the test date…”. We request that this portion of Condition IX.G.10 be revised to read: “Permittee shall submit a CEMS certification test plan to the EPA no later than 30 days prior to the test date…”.

8) Performance Tests

a. Condition IX.H.1.a.iii and iv of the proposed PSD permit requires that the 2,000 kW engine (Unit D7) and the firewater pump (Unit D8) complete initial and annual performance tests for NO_x, CO, PM, and PM10 (as a surrogate for PM2.5). We believe that the performance testing requirement contained in this condition is excessive for emission units that are limited to 50 hours per year of non-emergency operation and will be certified by the engine manufacturer to meet the emission standards. Therefore, we request that the requirement for annual testing of these units be deleted. Source testing would take additional time over what is needed for the normal testing (i.e., starting the engine to make sure that it is in operating condition, per Fire Department safety requirements), and hence if EPA does require such testing, it would require the engine to be run for more than 50 hr/yr for non-emergency purposes, which would then make the engine no longer exempt from California emission limits for diesel engines.

b. Condition IX.H.1.a.v of the proposed PSD permit requires initial and annual PM testing from the cooling tower. After submittal of the PSD application, the Applicant’s consultant, Ms. Sara Head, had several discussions with Mr. Ed Pike of the EPA. Mr. Pike indicated that source testing of the cooling tower would only be required if an assumption that less than 100% of the TDS in the tower was assumed to be emitted as PM10. Therefore, it was agreed that the PM10 (and PM2.5) emissions from the cooling tower would be assumed to equal the PM emissions (see comment 2 above). This assumption was used in the subsequent supplemental submittals related to PM and PM2.5 emissions for the VV2 Project. Therefore, the requirement to source test the cooling tower should be deleted from the permit.

c. Condition IX.H.1.b of the proposed PSD permit states: “The annual performance tests shall be conducted in accordance with the requirements of 40 CFR Part 60, Appendix F, Procedure 1, Section

5.11.". Appendix F, Procedure 1 does not contain a Section 5.11. In addition, we do not see the applicability of Appendix F, Procedure 1 (QA Requirements for CEMS) to the performance test requirements of Section H of the proposed permit. We request that Condition IX.H.1.b be removed from the permit.

d. Condition IX.H.1.f of the proposed PSD permit states: "The performance methods specified in Condition X.F.3 may be modified as follows:". The proposed PSD permit does not contain condition X.F.3. The language of Condition IX.H.1.f.i and ii appear to be similar to 40 CFR 60.4405 which is applicable to performance of the initial certification testing required by 40 CFR 60 Subpart KKKK for a CTG that has selected to install a NO_x CEMS. Therefore, we believe that Condition IX.H.1.f should be revised to read: "The performance methods specified in Condition IX.H.1.d.i and ii may be modified as follows:" or removed from the proposed permit.

e. Condition IX.H.3.a of the proposed PSD permit states the following: "Permittee shall take monthly samples of the natural gas combusted…." The requirements of 40 CFR 60 Subpart KKKK allow the approval of custom fuel monitoring schedule approved by EPA for compliance with the fuel monitoring provisions. We believe that the fuel data that will be provided by the gas supplier will be sufficient to provide the necessary information. Therefore, we request that this condition be revised for consistency with the FDOC to allow that sulfur content of natural gas combusted at the facility shall be obtained by the Permittee through laboratory analysis or natural gas sulfur content reports from the natural gas supplier(s).

We appreciate your consideration of these comments. For your convenience, we have also provided these comments as a mark-up of the proposed PSD permit. Please contact me at 805-388-3775 if you have any questions about these comments regarding the proposed PSD permit for the VV2 Project.

Sincerely yours,

Sara J. Head

Sara J. Head
ENSR Project Manager
shead@ensr.aecom.com

cc: Jon Roberts, City of Victorville
Tom Barnett, Inland Energy
Michael Carroll, Latham & Watkins LLP
John Kessler, CEC
Alan DeSalvio, MDAQMD

VICTORVILLE ~~H~~2 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~~kW (2,683 hp) Internal Combustion (IC) Diesel-fired Emergency Engine
D8	• 135 ~~KW~~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**	**124~~0~~.5~~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	• 154.6 lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2
CO	• 7.04~~65~~ lb/hr • 1-hr average • 2.0 ppmvd @ 15% O_2	• 14~~3~~.2~~3~~5 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 4,000~~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.

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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	110 minutes~~1.8 hr~~/event	~~50 events/yr~~
Warm and Hot Startup	30 lb/hr 40 lb/event	247 lb/hr 329 lb/event	80 minutes~~1.3 hr~~/event	~~260 events/yr~~
Shutdown	114 lb/hr 57 lb/event	674 lb/hr 337 lb/event	30 minutes~~0.5 hr~~/event	~~310 events/yr~~

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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**:**

	NO_x	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~~kW (2,683 hp) engine	• 6.4~~0~~ g/~~KW~~kW-hr, (4.8~~5~~ g/hp-hr)[1]	• 3.5 g/~~KW~~kW-hr, (2.6 g/hp-hr)	• 0.20 g/~~KW~~kW-hr, (0.15 g/hp-hr~~–~~) • Use of ultra-low sulfur fuel, not to exceed 15 ppmvd fuel sulfur	• Use for emergency power only • Not to exceed 50 hr/yr for testing and maintenance
Unit D8 135 ~~KW~~kW (182 hp) firewater pump	• 4.0~~3.8~~ g/~~KW~~kW-hr, (3.0~~2.8~~ g/hp-hr)~~[2]~~			~~As required for fire safety testing~~ • Not to exceed 50 hr/yr for testing and

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[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.

				maintenance
Unit D9 130,000 gpm Cooling Tower	n/a	n/a	• 1.6 lb/hr (as total PM) • < 0.0005% drift • ≤~~<~~ 5,000 ppm total dissolved solids	n/a

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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. 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.~~5.The initial certification ~~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~~certification testing on or before the date of the initial performance test.

~~7.~~6.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.~~7.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.~~8.The gas turbine CEMS shall be audited quarterly and 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.~~9. Permittee shall submit a CEMS ~~performance~~ certification test plan~~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.~~10. Permittee shall furnish the EPA a written report of the results of performance tests within 60 days of completion.

~~12.~~11. 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.

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~~13.~~12. 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).

~~ii.~~

~~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.~~b. 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.~~c. 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

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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 ºC oven as described in the first sentence of section 5.3.2.3. and

~~v. Modified Method 306 or the Cooling Tower Institute's heated bead test method for PM emissions from the cooling tower, and~~
~~vi.~~v. the provisions of 40 CFR Part 60.8 (f).

~~e.~~d. 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.~~e. 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.

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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.~~f. 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.~~g. 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.~~h. 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 an 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. S~~Permittee shall take monthly s~~amples of the natural gas combusted shall be collected on a monthly basis and ~~. The samples shall be~~ analyzed for sulfur content using an ASTM method. The samples can be collected and analyzed by the Permittee or be provided by the natural gas supplier(s). 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~~kW emergency use engine (Unit D7) and the 135 ~~KW~~kW emergency-use firewater pump (Unit D8).

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J. Recordkeeping and Reporting

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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.

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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 30th 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

AQMD~~PCD~~	Air Quality Management ~~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~~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