STATE OF CALIFORNIA — THE RESOURCES AGENCY ARNOLD SCHWARZENEGGER, *Governor*

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

DATE: June 8, 2005

TO: Interested Parties

FROM: Connie Bruins, Compliance Project Manager

SUBJECT: Inland Empire Energy Center Power Project (01-AFC-17C) Staff Analysis Of Proposed Modifications To Change To GE 107H Combined-Cycle Systems, Increase Generation and Add Additional Laydown Areas

On March 11, 2005, the California Energy Commission received a petition from Inland Empire Energy Center, LLC, (IEEC) to amend the Energy Commission Decision for the Inland Empire Energy Center Power Project.

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located on approximately 45.8 acres near the community of Romoland in unincorporated Riverside County.

IEEC requests to change the previously-approved power generation configuration that consists of two GE Frame 7F combustion turbine-generators. The proposed new configuration would consist of two GE 107H combined-cycle systems (H System). The H System represents GE's latest gas turbine technology providing superior fuel economy and environmental performance. This proposed modification would require changes to the site layout concerning location of structures and add approximately four acres to the fenced area of the project site.

In addition, IEEC requests to add two temporary areas near the project site for construction worker parking and secondary laydown. The additional 11.5 acres will allow for a more efficient use of the project site during construction and safer, more cost-effective construction staging.

Energy Commission staff reviewed the petition and assessed the impacts of this proposal on environmental quality, public health and safety.

- Staff determined that no changes to conditions of certification are required for the technical areas of efficiency, geology, mineral resources and paleontology, reliability, traffic and transportation, and transmission line safety and nuisance.

- Staff prepared new and/or made revisions to existing conditions of certification for air quality, biology, facility design, hazardous materials, noise, reliability, soil and water resources, transmission system engineering, and worker safety and fire protection. It is staff's opinion that with the implementation of revised conditions for these technical areas, the project will remain in compliance with applicable laws, ordinances, regulations, and standards and that the proposed modifications will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

The amendment petition and staff's analyses have been posted on the Energy Commission's webpage at energy.ca.gov/sitingcases/inlandempire/index.html. Staff's analyses are enclosed for your information and review. The order will also be posted on the webpage if the amendment is approved. Energy Commission staff intends to recommend approval of the petition at the June 22**,** 2005 Business Meeting of the Energy Commission. If you have comments on this proposed modification, please submit them to me at the address below prior to June 22, 2005:

Connie Bruins
Compliance Project Manager
California Energy Commission
1516 9th Street, MS 2000
Sacramento, CA 95814

Comments may be submitted by fax to (916) 654-3882, or by e-mail to cbruins@energy.state.ca.us. If you have any questions, please contact Connie Bruins, Compliance Project Manager, at (916) 654-4545.

Enclosure

PETITION TO CHANGE TO GE 107H COMBINED-CYCLE SYSTEMS
INLAND EMPIRE ENERGY CENTER (01-AFC-17C)

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SUMMARY, CONCLUSION AND STAFF RECOMMENDATION

BACKGROUND

On March 11, 2005, Inland Empire Energy Center, LLC (IEEC), filed a petition with the California Energy Commission requesting to modify the Inland Empire Energy Center Project. The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

The Inland Empire Energy Project was certified using the most modern, fuel efficient gas-fired generating technology then commercially available, the GE Frame 7F gas turbine generator in a combined-cycle configuration. In recent years, GE has pursued development of the H-technology gas turbine. The first H machine, a 50 Hz Frame 9H unit rated at 480 MW, was installed at Baglan Bay, Wales, and began operational testing in November 2002. The first 60 Hz Frame 7H machine was ordered by Sithe Energies for installation at the Heritage Power Station in Scriba, NY, but the order was subsequently cancelled due to unfavorable economic conditions.

GE proposes to install, operate and test this initial Frame 7H machine. In order to pursue this essential step in the development and marketing of this new product, GE has completed an agreement with Calpine to install the first Frame 7H machine, along with a second machine, at the IEEC. Substituting these two larger capacity machines for the Frame 7F machines initially certified necessitates this amendment.

PROPOSED AMENDMENT

IEEC requests to change the previously-approved power generation configuration that consists of two GE Frame 7F combustion turbine-generators. The proposed new confirguration would consist of two GE 107H combined-cycle systems (H System). The H System represents GE’s latest gas turbine technology providing superior fuel economy and environmental performance. This proposed modification would require changes to the site layout concerning location of structures and add approximately four acres to the fenced area of the project site.

In addition, IEEC requests to add two additional temporary areas for construction worker parking and secondary laydown. The additional 11.5 acres will allow for a more efficient use of the project site during construction and safer, more cost-effective construction staging.

Key revisions to the site layout are proposed as follows:

- The combustion turbines (CT) and steam turbines (ST) will share common shaft lines, and will be pedestal mounted at the ST elevation.

- Each of the two STs will have a dedicated 8-cell cooling tower. These two towers will replace the previously-approved single 14-cell cooling tower.
- The entire facility will be moved approximately 80 feet to the south (within the same site boundaries).
- A chiller and space for a future thermal storage tank will be added and located in the area between the two heat recovery steam generators (HRSGs). This system will provide chilled water for cooling of the CT inlet air, replacing the fogging systems used in the previous configuration.
- Onsite gas compressors with fin-fan coolers and condensate storage tanks will be added.
- A second standby generator will be added such that each CT/ST/HRSG train will have a dedicated standby generator.
- The switchyard will be changed to a radial-feed configuration instead of a ring bus configuration, thus reducing the size of the switchyard. The switchgear building will be replaced by a number of smaller power distribution centers.
- The storm water pond will be eliminated. Instead, storm water will discharge into a regional flood control channel with vegetated swales to remove silt from the facility storm water discharge.
- The locations of various plant equipment will be revised including the aqueous ammonia storage tanks, hydrogen tube trailers and the auxiliary boiler.

IEEC indicates that their proposed modifications would increase generation from 670 to 810 megawatts, increase operational efficiencies, and enhance the project's economics with only minor changes in air emissions.

SUMMARY OF STAFF ANALYSES

The petition was reviewed by Energy Commission technical staff for potential environmental effects and consistency with applicable laws, ordinances, regulations and standards (LORS). Many of the proposed project features and potential environmental effects were previously analyzed by staff during their review of the original IEEC Project Application for Certification. Where applicable, staff referred to those previous environmental assessments in the attached analyses of the H System amendment petition. Staff determined that the technical areas of cultural resources, facility design, power plant efficiency, geology, land use, mineral resources and paleontology, power plant reliability, socioeconomics, transmission system engineering and transmission line safety and nuisance were not affected by the proposed changes, and no revisions or new conditions of certification are needed to ensure the project remains in compliance with all applicable LORS.

Staff determined that the following technical or environmental areas will be affected by the proposed project change to H System operations and has proposed new and revised conditions of certification in order to assure compliance with LORS and to reduce potential environmental impacts to a level of insignificance.

- **Air Quality**: Because commissioning would take longer than that proposed for the original project, revisions to AQ COCs would allow commissioning activities on one gas turbine unit simultaneously with baseload operation of the other. Staff also recommends changes to allow simultaneous startup of the two gas turbine units as long as new emission limits are not exceeded.

New mitigation has also been established with District conditions addressing the changed equipment, and to require a Memorandum of Understanding for establishing visibility baseline data at nearby Class I areas.

Energy Commission AQ conditions revised to address the changed equipment include **AQ-SC8 to AQ-SC16**, and to implement current policies for greenhouse gases, staff also recommends adding a new condition (**AQ-SC17)** which requires the project owner to report the quantities of carbon dioxide emitted. In addition, all of the conditions required by the South Coast Air Quality Management District have been revised and two new District conditions have been added (**AQ-51 and AQ-52**).

It is possible that after further review, the SCAQMD may revise the conditions in the Final Determination of Compliance, or that the SCAQMD and Energy Commission staff may find that revisions are necessary to address comments provided during the public review period, which for the SCAQMD ends in July 1, 2005. If necessary, a revision to this analysis would be prepared that provides any additional changes to the COCs.

- **Biological Resources**: The only identified impact from the proposed project was an increase of disturbance within potential Stephens' kangaroo rat habitat. Staff has recommended a change to Condition of Certification **BIO-11** that will reduce the impact to less than significant levels. The project will be in compliance with all LORS after adoption of the modified condition.

- **Noise and Vibration**: The project owner proposes to add high pressure air blow to Noise Condition of Certification **NOISE-4** as an available option. This option is not expected to create noise levels higher than those generated by the high pressure steam blow and will not create any additional noise impacts on the noise sensitive receptors.

- **Hazardous Materials Management**: The design changes proposed are fully mitigated with implementation of the existing conditions of certification, and with the additional Condition of Certification (**HAZ-13**) proposed by staff to address safety at the natural gas compressor building. With staff's proposed mitigation measures, the project will comply with all applicable LORS and will pose little potential for significant impacts on the public from the use and handling of hazardous materials.

- **Soil and Water Resources**: The proposed modifications would not cause any significant direct, indirect, or cumulative impacts to soil and water resources so long as the project owner continues to participate in the ongoing flood-control planning that is being undertaken by Riverside County. Staff will verify the project owner's participation in this planning through modified Conditions of Certification **SOIL & WATER-3, -7 and -8** which staff proposes for adoption. After adoption of these revised Conditions of Certification and adherence to the other Conditions of Certification as adopted in the Commission Decision, the project as modified would be in conformance with all LORS.

- **Visual Resources and Visual Plume Modeling**: With the effective implementation of the original Conditions of Certification and minor modifications to Condition of Certification **VIS-3** the visual impacts from the modified project would be reduced to a less than significant level. Because the method of calculating the plume frequency has been improved, the threshold for determining whether plume frequency is significant or not has been changed from 10 percent to 20 percent of seasonal daylight clear hours. This required additional modifications to condition **VIS-8**.

- **Worker Safety and Fire Protection**: With the provision of a Project Construction Safety and Health Program and a Project Operations and Maintenance Safety and Health Program as required by Conditions of Certification **WORKER SAFETY-1 and -2,** and compliance with the requirements of proposed new conditions **WORKER SAFETY-3 and -4**, staff has determined that the project will incorporate sufficient measures to ensure adequate levels of industrial safety, will comply with applicable LORS and will not have significant impacts on local fire protection services.

STAFF CONCLUSION AND RECOMMENDATION

Staff concludes that the following required findings mandated by Title 20, section 1769(a)(3) of the California Code of Regulations can be made and will recommend approval of the petition to the Energy Commission:

A. There will be no new or additional unmitigated significant environmental impacts associated with the proposed changes,

B. The facility will remain in compliance with all applicable laws, ordinances, regulations and standards,

C. The change will be beneficial to the project owner by increasing operational efficiencies and enhancing the project's economics. Moreover, the change will be beneficial to the State of California by increasing power in an area of need (Southern California).

D. There has been a substantial change in circumstances since the Commission certification justifying the change. The H System represents GE's latest gas turbine technology providing superior fuel economy and environmental performance.

AIR QUALITY ANALYSIS
BREWSTER BIRDSALL AND WILLIAM WALTERS

AMENDMENT REQUEST

On March 11, 2005, Inland Empire Energy Center, LLC (IEEC or project owner) proposed an amendment (Amendment No. 1) to the Inland Empire Energy Center Project (IEEC 2005b). This amendment request seeks to amend IEEC's project design by changing the power generation configuration from the originally-approved system of two GE Energy 7FB combustion turbine generators with one steam turbine generator to a new two-unit GE 107H System (H System). Each H System unit would consist of a combustion gas turbine and a steam turbine configured on a single common shaft line driving a single generator. The proposed GE 107H System would be the most efficient gas turbine combined-cycle design currently available to the power industry, and it would provide superior fuel economy and environmental performance (IEEC 2005b, p. ES-1).

The amendment also requests the addition of approximately 11.5 acres of construction worker parking and secondary laydown area northwest and adjacent to the existing project parcel to allow for more efficient use of the project site during construction and safer, more cost-effective construction staging.

The Final Staff Assessment (FSA) for the original IEEC design was released in May 2003, and the decision was adopted in December 2003. Because of the time that has passed and because the proposed changes would affect every source described in the original assessment, the air quality analysis represents a full update of the original assessment.

The setting, project emissions, and project impacts are fully updated by this analysis, and several of the Conditions of Certification (COCs) have been revised. All of the District COCs have been revisited by the South Coast Air Quality Management District (SCAQMD), and the additions and revisions required by the District are shown in this analysis. District COCs have been renumbered in some instances. Of the staff conditions: revisions to **AQ-SC9** are necessary because of the changed facility-wide emissions, revisions to **AQ-SC11** and **AQ-SC12** are necessary because of the changed cooling tower configuration, revisions to **AQ-SC13** are necessary because of the extended commissioning activities, and although the project owner requested that **AQ-SC14** be deleted, it has instead been revised to establish an emission limit during combined startup modes.

BACKGROUND

The original IEEC project was certified by the Energy Commission in December 2003 with two GE 7FB combustion turbines generators, a separate condensing steam turbine generator, an auxiliary boiler for providing offline steam, one 14-cell evaporative cooling tower, and one natural gas-fired emergency generator. Each of these systems and emission sources would be replaced with the proposed H System. Construction of the original IEEC project has not yet commenced.

The amendment petition request would allow the first installation of the GE 107H System in the United States. In Wales, United Kingdom, GE has been operating a combined-cycle power plant based on the similar, but larger, 109H System at the Baglan Bay Power Station. The Baglan Bay project was first fired in November 2002. Because of its location, age, and commercial interests, only limited emissions data was available to Energy Commission staff from the Baglan Bay project for review of the IEEC amendment. In lieu of a long record of independently-verified air emissions data, staff assumed an especially conservative position during its review of the project owner's information. Beyond the typical involvement of the project owner, GE representatives have also provided clarifying information where necessary. Staff believes that the performance of the proposed project should meet the project owner's current expectations, however, as with any emerging technology, the proposed project involves a heightened risk of underperformance.

The proposed modifications would involve substantial changes to almost every aspect of the original air quality analysis because every originally-approved emission source would be changed by the proposed project modifications. To address these changes, SCAQMD conducted a new evaluation for IEEC. The SCAQMD commenced review of the proposed amendment in February 2005, and issued a Preliminary Determination of Compliance on May 17, 2005 (SCAQMD 2005b). After a 30-day public comment period, a Final Determination of Compliance may be issued by SCAQMD. If the Final Determination of Compliance involves revised permit conditions, Energy Commission staff would then need to update this analysis.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Air Quality were identified in staff's Final Staff Assessment. These LORS would continue to apply to the amended project with the following revisions:

RULE 431.2 – SULFUR CONTENT OF LIQUID FUELS.

In the original analysis, the sulfur content limit for diesel fuel used by the project was limited to 0.05 percent by weight. This has been revised downward to require use of only ultra-low sulfur diesel, or 0.0015 percent sulfur by weight (15 ppmw), as shown in COC **AQ-3**.

AIR QUALITY ANALYSIS

SETTING

Air Quality Standards and Attainment Status

The project is located in the South Coast Air Basin portion of Riverside County within the jurisdiction of the SCAQMD. The ambient air quality standards (AAQS) for particulate matter have been updated since the FSA was completed, and the State of California recently proposed a new 8-hour standard for ozone. The current standards are presented in **Table 1**. The standards are given as a mass fraction, in parts per million (ppm), or as a concentration, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 and $\mu g/m^3$).

Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.08 ppm (157 $\mu g/m^3$)	— *(*0.070 ppm)*
	1 Hour	0.12 ppm (235 $\mu g/m^3$)	0.09 ppm (180 $\mu g/m^3$)
Respirable Particulate Matter (PM10)	Annual Arithmetic Mean	50 $\mu g/m^3$	20 $\mu g/m^3$
	24 Hour	150 $\mu g/m^3$	50 $\mu g/m^3$
Fine Particulate Matter (PM2.5)	Annual Arithmetic Mean	15 $\mu g/m^3$	12 $\mu g/m^3$
	24 Hour	65 $\mu g/m^3$	—
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 $\mu g/m^3$)	—
	1 Hour	—	0.25 ppm (470 $\mu g/m^3$)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	0.030 ppm (80 $\mu g/m^3$)	—
	24 Hour	0.14 ppm (365 $\mu g/m^3$)	0.04 ppm (105 $\mu g/m^3$)
	3 Hour	0.5 ppm (1300 $\mu g/m^3$)	—
	1 Hour	—	0.25 ppm (655 $\mu g/m^3$)
Sulfates (SO_4^{2-})	24 Hour	—	25 $\mu g/m^3$
Lead	Calendar Quarter	1.5 $\mu g/m^3$	—
	30 Day Average	—	1.5 $\mu g/m^3$
Hydrogen Sulfide(H_2S)	1 Hour	—	0.03 ppm (42 $\mu g/m^3$)
Vinyl Chloride (chloroethene)	24 Hour	—	0.010 ppm (26 $\mu g/m^3$)
Visibility Reducing Particulates	1 Observation	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

Source: CARB, 2005a.

*Note: On April 28, 2005, the California Air Resources Board approved a new ozone standard that will take effect upon final approval by the Office of Administrative Law expected in 2006.

Recent implementation of the 8-hour standard for ozone and standards for PM2.5 have led to changes in the categorization of air quality in the IEEC project area. **Table 2** summarizes the federal and State attainment designations for the project area.

Table 2
Federal and State Attainment Status for Riverside County, South Coast Air Basin [a]

Pollutants	Federal Classification	State Classification
1-hour Ozone	Extreme Nonattainment	Extreme Nonattainment
8-hour Ozone	Severe-17 Nonattainment [a]	---
PM10	Serious Nonattainment	Nonattainment
PM2.5	Nonattainment [a]	Nonattainment [a]
NO_2	Unclassified/Attainment	Attainment
CO	Nonattainment [b]	Attainment
SO_2	Attainment	Attainment

Source: USEPA 2005. CARB 2005b.
Note(s):

a. At the time of the original licensing of IEEC, there were no formal designations for these categories.
b. Because of CO violations in Los Angeles County, portions of the South Coast Air Basin are designated nonattainment. The federal classification for CO nonattainment applies to the entire basin; state-level nonattainment for CO applies to only Los Angeles County.

Criteria Pollutant Air Quality Data

Since the original IEEC licensing, additional ambient air quality data has become available. **Table 3** reflects the most recent data of the last five years. The highest background concentrations from the latest three years of data are shown in bold for use in this impact analysis.

There is no discernable downward trend in the five years of ambient concentration data for any criteria pollutant shown in **Table 3** except CO. This is the result of two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state.

Table 3
Ambient Air Quality Monitoring Data (ppm)

Pollutant -Location-	Averaging Time	2000[a]	2001[a]	2002[b]	2003[b]	2004[b]	Most Restrictive Ambient Air Quality Standard
Ozone	1 hour	0.164	0.152	0.147	**0.155**	0.128	0.09 (Cal.)
-Perris-	Days Exceeding 1 hour Standard	65	73	59	67	36	---
	8 hour	0.126	0.135	0.117	**0.121**	0.104	0.08 (Fed.)
PM10 (μg/m³)	24 hour	87	86	100	**142**	83	50 (Cal.)
-Perris-	Days Exceeding 24 hour Standard[1]	78	96	144	114	90	---
	Annual Arithmetic Mean	41.1	40.9	**45.1**	43.9	41.4	50 (Fed.)
PM2.5 (μg/m³)	24 hour	79.3	74.9	75.5	73.3	**93.8**	65 (Fed.)
-Magnolia St.-	Annual Arithmetic Mean	25.3	28.2	**27.1**	22.6	20.8	12 (Cal.)
NO_2	1 hour	0.078	0.091	0.074	0.074	**0.090**	0.25 (Cal.)
-Lake Elsinore-	Annual	0.017	0.018	0.017	**0.018**	0.015	0.053 (Fed.)
CO	1 hour	**8.8**	5.8	---	---	---	20 (Cal.)
-Magnolia St.-	8 hour	4.23	4.47	**3.75**	3.33	2.46	9 (Fed.)
SO_2	1 hour	**0.11**	0.02	---	---	---	0.25 (Cal.)
-Rubidoux Ave.-	24 hour	0.038	0.009	0.003	0.012	**0.015**	0.04 (Cal.)
	Annual	0.001	0.001	---	0.002	**0.004**	0.03 (Fed.)

Note: 1. Monitoring for the 24-hour PM10 standard is performed once every six days, and the number of days shown exceeding the standard is the actual number of measured days times six.
2. No single station in the area monitors all pollutants. The representative station nearest the project site is used in each case.
3. Recommended background concentrations are shown in bold.

Sources: a. CARB Air Quality Data CD, 2002.
b. CARB web site, http://www.arb.ca.gov/adam/welcome.html, accessed April 2005.

PROJECT DESCRIPTION CHANGES

Equipment Description Changes

The following equipment revisions would result in substantial changes to the air quality analysis (IEEC 2005b, pp. 2-1 to 2-13):

- Two GE 107H System units, each of which would consist of a combustion gas turbine and a steam turbine configured on a common shaft line driving a single generator. The separate steam turbine generator originally proposed would be eliminated. As before, the combustion turbines would fire exclusively natural gas and would be equipped with dry low-NOx combustors for NOx reduction, and the exhaust from each combustion turbine would discharge into a dedicated three-pressure heat recovery steam generator (HRSG). As with the previous configuration, each HRSG includes a selective catalytic reduction (SCR) system to further reduce NOx emissions and an oxidation catalyst to reduce CO and VOC. The duct firing capability of the original HRSG systems would be eliminated. Instead of inlet air fogging, a chilled water system would be used to cool combustion turbine inlet air, extending the range of ambient conditions over which inlet cooling can be used. For base load operation of each unit at average ambient conditions, with inlet air cooling, each unit will produce approximately 405 MW (gross) of power and consume approximately 2,503 MMBtu/hr of natural gas on a higher heating value (HHV) basis. The maximum heat input of each H System unit of 2,597 MMBtu/hr would, therefore, be only marginally higher than the peak heat input of the original 7FB design with duct burning (2,510 MMBtu/hr). The net power output for the two GE 107H System units, after taking away auxiliary loads of 20 MW, is approximately 790 MW.
- The feature of power augmentation using steam injection would be eliminated. The combustion turbine fuel gas, however, would be moisturized to increase mass flow through the combustion turbine, thus increasing power output.
- The spacing between the centerlines of the two combustion turbine/steam turbine/HRSG trains has been increased to allow sufficient space around the units for auxiliary equipment, including permanently installed bridge/gantry cranes. The stacks have been separated, where in the original design they had been merged.
- Each of the two units would have a dedicated 8-cell cooling water tower, compared to the single 14-cell cooling water tower in the previous configuration. The maximum drift would remain limited to 0.0005 percent of the circulating water flow. This results in a combined flow rate for the two towers of 179,194 gallons per minute (gpm), an increase of 9,347 gpm.
- 157 MMBtu/hr natural gas-fired auxiliary boiler capable of providing up to 120,000 lb/hr of saturated steam for expediting startup of the steam cycle. The auxiliary boiler would include a low-emissions burner and SCR system. Unlike the previous design, which consisted of a smaller auxiliary boiler, the project owner presently proposes this equipment without an oxidation catalyst, although it would still meet the emission limits required by the District.

- Instead of a single 1,000 kW natural gas-fired emergency generator, two 2,000 kW diesel-fired emergency generators at 2,848-hp would be provided for standby power. The diesel engines would be equipped with soot filters to reduce particulate matter. Each combustion turbine/steam turbine/HRSG train would have a dedicated emergency generator to enhance reliability and flexibility by creating a true two unit system and the ability to operate one unit during downtimes of the second unit.
- The diesel-fueled fire water pump size would be decreased from 370-hp to 300-hp.
- Changes to facilities for natural gas fuel supply, include a proposed onsite electric-powered gas compression system with fin-fan coolers.

Emission Controls

The two H System units would be fired on pipeline-quality natural gas exclusively. This fuel limits the formation of PM10, SO_2, and VOC emissions. The project owner expects the natural gas supply to contain less than 0.25 grains of sulfur per 100 scf, as in the original design. Furthermore, each combustion turbine would be equipped with dry low-NOx (DLN) combustors capable of controlling turbine exhaust NOx emissions to approximately 15 ppmvd at 15 percent oxygen (@ 15% O_2) during normal operation (IEEC 2005b, p. 2-22). SCR systems within the HRSGs would further reduce NOx emissions to a maximum of 2.0 ppmvd @ 15% O_2, measured at the stacks during normal operation (IEEC 2005b, p. 2-22). Stack emissions of ammonia shall not exceed 5 ppmvd @ 15% O_2, during normal operation, as required by the original decision (IEEC 2005b, p. 2-22). Oxidation catalyst would also be included in the HRSGs to limit CO emissions to 3.0 ppmvd @ 15% O_2 and to ensure that emissions of VOC are controlled to less then 2.0 ppmvd @ 15% O_2 (IEEC 2005b, p. 2-23). These limits, which are agreed-upon by GE, would match those of the original IEEC design (IEEC 2005b, p. 3-4).

The project owner proposes to reduce the PM10 limit from approximately 10.5 lb/hr, as it was for the original design with duct burning, to 10 lb/hr per combustion turbine. The project owner believes that this reduction of approximately five percent, per unit of fuel fired, is justifiable based on test results of F-class combustion turbines located at Calpine’s Sutter Energy Center, Los Medanos Energy Center, and Delta Energy Center (IEEC 2005b, Appendix A.4 to 3.1-4). Staff has reviewed the test results submitted with the amendment and agrees that this level should be achievable by the H System units when using test methods approved by SCAQMD.

Compliance would be tracked much in the same way as originally approved. As with the original design, a continuous emission monitoring system (CEMS) would be installed on the exhaust stack for NOx, CO and oxygen to assure adherence with the proposed emission limits. Ammonia concentrations would also be monitored by a continuous emission monitoring device, as specified by the original decision.

The auxiliary boiler would be equipped with a low-emissions burner and SCR system, capable of meeting stack emissions levels of 7 ppmvd NOx, 50 ppmvd CO, and 10 ppmvd VOC, all at 3 percent oxygen (IEEC 2005b, p. 2-23). The project owner proposes to meet these limits without the use of an oxidation catalyst.

All three diesel engines would achieve BACT defined by SCAQMD. The two diesel-fired emergency generator engines would be equipped with soot filters to reduce particulate matter. Each of these 2,848-hp standby engines would be required to achieve emission rates of 6.2 g/bhp-hr NOx, 0.45 g/bhp-hr CO, 0.015 g/bhp-hr PM10, 0.03 g/bhp-hr VOC (SCAQMD 2005b). The 300-hp diesel-fired water pump engine emission rates would be limited to 5.2 g/bhp-hr NOx, 0.3 g/bhp-hr CO, 0.1 g/bhp-hr PM10, and 0.2 g/bhp-hr VOC (SCAQMD 2005b). As with the original decision, only "ultra-low sulfur" diesel fuel would be used in these engines, meaning the sulfur content of the fuel would be limited to no more than 15 ppmw (IEEC 2005i, Resp. 39).

AMENDED PROJECT EMISSIONS AND IMPACTS

Construction Activities

Construction the project would involve a greater area of disturbance and a longer duration of activity when compared to the original IEEC. The original project required development of approximately 35 acres of the approximately 46-acre site. As with the original project, the construction activities would include site mobilization (creation of temporary roads, laydown, and work areas), all ground disturbing activities (grading, topsoil storage, installation of underground utilities both on- and off-site), construction and fabrication of the power plant (including major and ancillary equipment, delivery of equipment by rail and truck, transportation of workers, etc.), and commissioning tasks prior to routine operation of the plant.

Construction of IEEC, from site preparation and grading to commercial operation, originally expected to require 22 months, is now expected to occur from the summer of 2005 to the summer of 2008, requiring a total of 36 months (IEEC 2005b, p.2-31). The actual construction duration from the start of construction to "substantial completion" is estimated to be 26 months (IEEC 2005b, p. 2-31), but after substantial completion, commercial operation would be delayed to allow for an extended commissioning phase with a "characterization program," described separately below.

The original project required two laydown areas totaling 22 acres (CEC 2003a). With this amendment, two additional parcels of 9.6 and 1.97 acres would be added. Most of the additional area would be located northwest of the project site, on the west side of Antelope Road (IEEC 2005b, p. 2-34). The temporary disturbance area for construction of the project would increase to approximately 45 acres, while the permanent disturbance area would be approximately 38 acres (IEEC 2005b, p. 2-32). The construction workforce would peak at up to 750 during the month of the most intense activity (IEEC 2005b, p. 2-33) compared to the original project, which involved roughly 400 workers during the peak month (DBSR 2002m).

Although construction phase impacts would be somewhat affected by the proposed changes in construction area and duration, the conclusions reached in the original FSA and the findings of the original decision would not be changed. The difference in sizes of the disturbed areas are principally related to increased graveled laydown and parking areas, which are not expected to substantially affect the construction emissions characterized in the FSA. The extended duration of construction activity implies that a reduced level of intensity per month would actually occur (IEEC 2005i), even if the peak monthly workforce may be somewhat larger.

The original FSA found that mitigation measures would be necessary to avoid the potentially significant impacts of particulate matter and ozone concentrations during construction, and various Conditions of Certification were identified and adopted. This conclusion and the adopted COCs remain applicable for this amendment, and staff recommends retaining **AQ-SC1** through **AQ-SC6** unchanged.

Commissioning and Characterization Activities

The original IEEC involved a sequence of commissioning activities that could be completed during the final 2-to-3 months of the construction phase. To address impacts, the original decision included a COC prohibiting simultaneous commissioning tests of the two combustion turbines (**AQ-SC13**).

Changes to Commissioning Activities

The purpose and duration of this phase of the project would be dramatically changed under the IEEC amendment. Because this project would be the first installation of the GE 107H System, the commissioning phase includes an extensive "characterization program" involving tests that are proprietary to GE (IEEC 2005i). The tests are needed in order for GE to prepare for deployment of the H System in the U.S. The characterization program requires more time than needed for a typical combined-cycle project, and it involves an extended period of normal operation prior to the declaration of commercial operation. The project owner allows approximately 10 months for commissioning and characterization of both units.

Commissioning normally involves a range of no load, partial load, and full load tests for optimizing turbine machinery. The combustors would operate in different modes (diffusion, piloted-premix, or premix mode) depending on turbine speed and load. Combustor tuning and synchronization occur during commissioning, and elevated emissions are expected because some activities occur without operation of the pollution control system in place and repeated startups and shutdowns are normally required. The expanded commissioning and characterization program for the H System units includes the following (IEEC 2005i, Resp. 18 and SCAQMD 2005b, Appx. A):

- No load tests: first fire, diffusion mode combustion mapping, piloted-premix mode combustion transfer tuning. Duration of approximately eight days for each combustion turbine.
- Aeromechanical validation: premix transfer tuning, premix and combined cycle full load. The SCR and CO catalyst would become operational during this period. Duration of approximately 21 days for each combustion turbine.
- Aerothermal validation: premix combustion mapping. Duration of approximately 21 days for initial unit and 9 days for second unit.
- Performance and off-design testing: premix mode testing. Duration of approximately 28 days for initial unit and 13 days for second unit.

- Final combustion testing: emissions, dynamics, fuel variation and variable guide vanes testing. Duration of approximately 25 days for initial unit and 2 days for second unit.
- Compliance testing: electrical grid and emissions compliance. Duration of approximately 7 days for initial unit and 4 days for second unit.

Increased downtime during commissioning and characterization would involve unit outages, when no additional emissions would occur. About 510 hours of fired operation would be needed to complete these tests for both units, with the majority of the time spent testing the initial unit (IEEC 2005d). Installation of the SCR system is expected to be completed prior to approximately 50 hours of fired operation or before the aerothermal testing phase (IEEC 2005i, Resp. 21).

Changes to Commissioning Emissions

The power generation industry possesses no experience with the emissions of the proposed H System units except from GE's Baglan Bay installation, and no commissioning emissions data was made available from Baglan Bay (IEEC 2005i). In the absence of field-verified data, commissioning and characterization activity emissions have been estimated by the project owner using GE's proprietary model of turbine performance, called the "cycle deck."

The project owner describes this computational model as follows (IEEC 2005i, Resp. 15):

> "*The cycle deck consists of a series of individual component models that can be combined together to predict the performance of individual turbine components through a complete combined cycle power generation system. The individual building blocks of the model are developed from first principles, and are then confirmed through laboratory testing of individual components. Component integration is evaluated and tested in the same manner. Data from field units are added to a data base to enhance the models predictive capability over time. The specific model elements for the 7H turbine were originally derived from comparable model elements for the 7F turbine, supplemented with engineering data from laboratory tests of new components and systems. The predictions from the model were compared with measurements at the Baglan Bay facility in Wales, and the results were found to be reasonably consistent. Nonetheless, test data from the Baglan Bay facility have been used to further refine the model's predictive capabilities, and it is these refined results that form the basis of the predictions presented for IEEC*."

The commissioning and characterization emissions predicted by the project owner are shown in **Table 4**, below. These emissions are averaged over each test including the effects of numerous startups and shutdowns with fired operation.

Table 4
Estimated Commissioning Emissions for IEEC (average lb/hr per turbine)

Commissioning Activity	NOx	CO	PM10	SO_x	VOC
No Load (either unit)	270	299	10	1.83	13
Aeromechanical (either unit)	199	63	10	1.83	5
Aerothermal (initial unit)	152	42	10	1.83	4
Aerothermal (second unit)	173	33	10	1.83	3
Performance & Off-Design (initial unit)	122	59	10	1.83	5
Performance & Off-Design (second unit)	147	34	10	1.83	4
Final Combustion (initial unit)	197	37	10	1.83	3
Final Combustion (second unit)	181	20	10	1.83	3
Compliance (initial unit)	180	43	10	1.83	3
Compliance (second unit)	208	36	10	1.83	3
Total Commissioning Emissions (both units, lb)	**85,729**	**27,871**	**5,085**	**931**	**2,176**
Maximum Single Hour (either unit, lb)	**587**	**777**	**10**	**1.83**	**13**

Source: IEEC 2005d and SCAQMD 2005b.
Note: Commissioning emissions of PM10 and SOx would be similar to routine operational emissions.

In order to manage commissioning and reduce the potential emissions, the original decision included a condition that prohibited simultaneous commissioning of the two combustion turbines (**AQ-SC13**). This amendment would involve an extended commissioning and characterization period during which the project owner proposes to operate one combustion turbine unit at steady state, while testing the other. Staff recommends revising this condition (**AQ-SC13**) to allow simultaneous steady state operation of one unit, as long as total commissioning activities do not exceed an hourly emission cap.

Analysis of Commissioning and Characterization Impacts

The original analysis found no significant impact to occur during commissioning. Commissioning tests at partial loads or without the emission control systems in place would cause emissions of NOx or CO exceeding those anticipated for routine startups. Because commissioning activities would occur over periods that would not be continuous, averaging periods longer than eight hours are not considered. Additionally, PM10 and SOx impacts are not discussed separately for commissioning because they would not be higher than those occurring under normal startup and operation, as described in the following sections. Emissions caused by the modified commissioning activities would change the originally-identified impacts but not substantially. The commissioning impacts are summarized in **Table 5**.

Table 5
IEEC Project, Commissioning Impacts (in μg/m^3)

Pollutant	Averaging Period	Project Impact	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
NO_2	1-hour	257	169	426	470	CAAQS	91
CO	1-hour	780	10,120	10,900	23,000	CAAQS	47
	8-hour	686	4,313	4,999	10,000	NAAQS	50

Source: Independent staff assessment.

Note: Based on worst of five years (1997-2001) of meteorological data from March AFB as described in FSA (CEC 2003a). NO_2 results for 2001 using 2001 ozone data provided the worst-case impacts, ozone limiting method (OLM corrected). Impacts of PM10 and SOx would be similar or less than the impacts that would occur during routine startups.

Conclusion for Commissioning and Characterization

The impacts associated with the proposed revisions to the commissioning activities would be greater than those presented for IEEC in the original analysis, but as with the original analysis, no significant impact would occur. Total concentrations of criteria pollutants would be within the applicable standards. As with the original analysis, commissioning emissions will be counted toward the annual emission limits for the facility, thus there is an incentive for the project owner to limit the commissioning emissions to the lowest possible levels. Staff recommends condition **AQ-SC13**, as revised, for limiting the combined emissions during commissioning.

Operational Phase

The power generation equipment related to the original IEEC project was found to cause potentially significant air quality impacts by emitting PM10 and precursors to PM10, PM2.5, and ozone. The original staff assessment and Energy Commission decision found that the project owner could fully mitigate these impacts by offsetting the emissions. Conditions of the original decision (**AQ-SC9** and others) require the project owner to provide RECLAIM Trading Credits (RTCs) for NOx, emission reduction credits (ERCs) for CO and VOC, and ERCs from the SCAQMD Priority Reserve program for SOx and PM10 (CEC 2003b). This amendment would not change the basic mitigation strategy (IEEC 2005b, p. 3-10); however, because it would change the power generation equipment, the analysis of operational impacts has been revisited.

Changes to Operating Emissions

The project owner's proposed hourly emission rates for criteria air pollutants are shown in **Table 6**. This table presents the revised emission rates for each combustion gas turbine unit, the two cooling towers, the auxiliary boiler, and the three standby or emergency engines. Compared to the original design, dramatically lower levels of CO emissions would occur as a result of the equipment change, and somewhat higher levels of NOx emissions would occur during startups. The project owner proposes slightly more stringent PM10 limits per unit of fuel consumption overall, and the overall SOx emissions would increase slightly because of the increase in annual fuel use and the change from one natural gas emergency generator engine to two diesel-fired emergency generator engines. The slight increase in VOC emissions is due mainly to higher heat inputs to the gas turbines during worst-case base load operating conditions.

Table 6
IEEC Project, Project Owner's Proposed Hourly Emissions
(pounds per hour, lb/hr)

Operational Profile	NOx	CO	PM10	SOx	VOC
Startup or Shutdown Modes					
Gas Turbine Startup or Shutdown (max lb/hr per unit in startup)	408	95	10	1.83	16
Gas Turbine Startup or Shutdown (average lb/hr per unit in startup)	125	50	10	1.83	16
Gas Turbine Cold Startup – 6 hour duration (lb per unit over full 6 hour duration)	803	300	60	11	48
Routine Operation Modes (lb/hr)					
Gas Turbine Hourly Maximum (per unit, ambient 36F)	18.8	17.2	10	1.83	6.6
Gas Turbine Hourly Average 50% Load (per unit)	9.6	8.8	10	0.93	3.3
Gas Turbine Average Annually (per unit)	18.1	16.6	10	1.76	6.3
Each Cell of Cooling Tower (8 cells each, 16 cells total)	---	---	0.22	--	--
Total for Cooling Towers	---	---	3.5	---	---
Auxiliary Boiler	1.32	5.73	1.12	0.11	0.66
Diesel-Powered Fire Pump Engine	3.44	0.18	0.06	0.10	0.10
Diesel-Fired Emergency Generator Engine (per engine)	41.75	6.34	0.15	0.99	0.88
Reasonable Worst-Case Hour: Both Gas Turbines in Startup + Cooling Towers + Auxiliary Boiler + Standby Generator Test	859	202	24.8	4.8	33.5

Sources: IEEC 2005b, Tables 3.1-2, 3.1-3, A.1-4 (Auxiliary Boiler), A.1-5 (Standby/Emergency Engines), A.1-6 (Cooling Tower), with IEEC 2005i, Resp. 36.

The proposed amendment requests no notable change in the anticipated operating schedule. The original IEEC project was to operate with roughly 50 cold starts and 100 hot starts per year (CEC 2003a), and the current proposal would allow 400 hours per year in either hot or cold startup modes (i.e., roughly 1 hour for each of 100 hot startups and a maximum of 6 hours for each of 50 cold startups). Annual emissions are based on each combustion turbine operating at baseload conditions for 8,360 hours, the auxiliary boiler operating 2,340 hours, the emergency engines each operating 50 hours, and the cooling towers each operating 8,760 hours (IEEC 2005b, Table A.1-2); however, the auxiliary boiler would be restricted to 600 hours per year according to SCAQMD calculations (SCAQMD 2005b). Daily emissions are estimated based on each combustion turbine operating at baseload conditions for 18 hours and 6 hours in startup mode, the auxiliary boiler operating 24 hours, one emergency generator engine operating 6 hours, and the cooling towers each operating 24 hours (IEEC 2005b, Table A.1-2). **Table 7** summarizes the project owner's reasonable worst case daily and annual emissions.

Table 7
IEEC Project, Project Owner's Proposed Maximum Emissions during Operation

Pollutant	NO_x	CO	PM10	SO_x	VOC
Maximum Daily Emissions (lb/day)	2,565.9	1,394.5	591.8	96.4	353.4
Maximum Annual Emissions (ton/year)	214.6	188.8	104.2	16.2	62.1

Source: IEEC 2005, Table 3.1-3.
Notes:
1. Daily emissions based on each of the two combustion turbines operating at 100% load for 18 hours and in startup mode for 6 hours, fulltime operation of the cooling towers and auxiliary boiler, and operation of one emergency generator engine for 6 hours.
2. Annual emissions based on each of the two combustion turbines operating at 100% load for 8,360 hours and in startup mode for 400 hours, fulltime operation of the cooling towers, operation of the auxiliary boiler for 2,340 hours, and operation of the three emergency engines for 50 hours each.

Dispersion Modeling Approach

The proposed equipment changes warrant a new analysis of the air contaminant impacts. For the original IEEC, staff conducted an air dispersion modeling assessment of the ground level concentrations of the pollutants emitted by the project. Staff reported the results of two approaches in the original assessment: first using 1981 Riverside meteorological data, as required by the SCAQMD, and then using alternative meteorological data from the former March AFB for the years 1997 to 2001. The first approach was used by the project owner although it is not preferred by staff because it requires determining NO_2 concentrations by pairing meteorological data from 1981 with ozone data from some other, more-recent year, subject to user choice. Pairing two disparate years of data as input to the model leads to physically impossible results (as described in CEC 2003a, p. 5.1-24). Staff's analysis for this amendment avoids using disparate years of meteorological and ozone data; the results below are obtained using the five years of data from March AFB. Staff's alternative approach leads to discrepancies with the project owner's results.

Analysis of Operating Phase Impacts

The original analysis found potentially significant air quality impacts because emissions of PM10 and precursors to PM10, PM2.5, and ozone would contribute to existing violations of these standards. Emissions caused by the changed equipment were analyzed to determine if the originally-identified impacts to ambient air quality would change. The emissions of unrestricted combined gas turbine startups were also analyzed at the project owner's request. The updated impacts of routine operations are summarized in **Tables 8 and 9**.

Table 8
IEEC Project Impacts from Routine Operations (in μg/m^3)

Pollutant	Averaging Period	Project Impact	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM10	24-hour	11.3	142	153	50	CAAQS	307
	Annual	0.8	45	46	50	NAAQS	90
NO_2	1-hour (a)	267.5	169	437	470	CAAQS	93
	Annual	1.1	34	35	100	NAAQS	35
CO	1-hour (a)	68.7	10,120	10,189	23,000	CAAQS	44
	8-hour (a)	28.5	4,313	4,341	10,000	NAAQS	43
SO_2	1-hour (a)	3.1	288	291	650	CAAQS	44
	24-hour (a)	1.5	39	41	105	CAAQS	39
	Annual	0.1	10	11	80	NAAQS	13

Source: Independent staff assessment.

Notes: Shows results using five years (1997-2001) of alternative meteorological data from March AFB. All impacts show the effects of combined startups and shutdowns as routine operations.

(a) Short-term NO_2, CO, and SO_2 impacts do not show the effects of occasional emergency engine testing. See below for impacts during periods when the fire pump or emergency generator engines are being tested. NO_2 results based on using OLM and ARM corrections, where appropriate.

Table 9
IEEC Project Impacts from Routine Operations during Engine Testing (in μg/m^3)

Pollutant	Averaging Period	Project Impact	Back-ground	Total Impact	Limiting Standard	Type of Standard	Percent of Standard
PM10	24-hour	11.3	142	153	50	CAAQS	307
NO_2	1-hour (a)	409.1	56.6 (a)	466	470	CAAQS	99
CO	1-hour	371.0	10,120	10,491	23,000	CAAQS	46
	8-hour	39.2	4,313	4,352	10,000	NAAQS	44
SO_2	1-hour	3.1	288	291	650	CAAQS	44
	24-hour	1.5	39	41	105	CAAQS	39

Source: Independent staff assessment.

Notes: Shows results using five years (1997-2001) of alternative meteorological data from March AFB. This table shows the effects of occasional emergency engine testing in conjunction with the effects of routine operations excluding startups.

(a) During hours when the fire pump or emergency generator engines are being tested, the maximum 1-hour NO_2 impact would be approximately 409 μg/m^3. Although this alone would represent 87 percent of the standard, when combined with background data from actual date and hour of the modeled maximum (56.6 μg/m^3), no violations were found. Other hourly impacts combined with worst-case background NO_2 data for the actual day of the modeled maximum revealed no violations for the remainder of the five-year period. The 1-hour NO_2 impacts are presented using OLM.

The maximum impacts from the combustion gas turbines would occur in the hills near Romoland, mainly to the south and east, at an elevation of roughly 400 feet over the base elevation of the project. A review of the modeling results shows that in the vicinity of the Romoland Elementary School, the maximum modeled 24-hour PM10 concentration caused by project operation would be about 1.1 μg/m^3, which would be about 1/10th of the maximum project impact shown in **Table 8**. This impact would be caused primarily by the auxiliary boiler source, not the combustion gas turbines. This means that when the plant is operating, the impacts at the school would be about 0.8 percent of the existing background conditions.

These impacts would be similar to those identified in the original analysis, and although numerous revisions to mitigation measures occur because of the changed equipment, these impacts would not warrant additional mitigation. To ensure that the NOx and CO performance of the new equipment during startups meets the project owner's expectations and that the short-term impacts portrayed in **Table 8** above remain valid, staff recommends establishing emission limits in **AQ-SC14** for combined startups of the gas turbines.

Analysis of Visibility Impacts

The project owner provided an analysis of impacts caused by the changed equipment to Class I areas in March 2005 (IEEC 2005c). The Federal Land Managers (FLMs) responsible for reviewing the analysis (U.S. Forest Service and National Park Service) provided comments and requested a range of revisions, and the project owner responded to these comments in letters dated April 11 and April 28, 2005 (IEEC 2005h and 2005k).

The two components of the original visibility analysis (coherent plume and regional haze) were revisited for this proposed amendment. The coherent plume analysis for the nearest Class I area (Agua Tibia Wilderness Area) revealed that the accepted U.S. Forest Service plume contrast criteria would not be exceeded with the proposed amendment. The regional haze analysis for distant Class I areas revealed that the changed project would exceed the FLM's threshold of potential significance by causing more than a five percent change in light extinction when compared to the background conditions at Joshua Tree National Park and the Cucamonga Wilderness Area. Although a similar impact that was identified at Joshua Tree for the original project and declared by the FLMs to be insignificant, the FLMs and the project owner now believe that improved background visibility data would improve the quality of regional haze impact predictions for projects like IEEC. Further study of background conditions along with operational data from other similar sources in the SCAQMD would help the FLMs to determine if similar projects will cause a significant degradation in visibility (IEEC 2005k and SCAQMD 2005b).

The FLMs have not formally determined the significance of the regional haze impact of the proposed amendment, but U.S. Forest Service staff expects to submit a formal response indicating a "non-adverse" impact determination during June 2005. Energy Commission Staff expects the FLMs to require participation of the project owner in a study program. The commitment of IEEC in the U.S. Forest Service visibility program would be formalized in a Memorandum of Understanding that should enable the FLMs to establish an improved visibility baseline in nearby Class I areas. This District condition is included in a revised version of COC **AQ-2**.

Greenhouse Gas Emissions Reporting

In addition to regulated criteria pollutants, the combustion of natural gas produces air emissions known as greenhouse gases. These include primarily carbon dioxide (CO_2)

and methane (unburned natural gas). Greenhouse gases are known to contribute to the warming of the earth's atmosphere, and climate change from rising temperatures represents a risk to California's economy, public health, and environment. In the 2003 Integrated Energy Policy Report, the Energy Commission recommended that the state should require reporting of greenhouse gas emissions as a condition of state licensing of new electric generating facilities. Accordingly, Staff recommends a new COC for IEEC (**AQ-SC17**) which requires the project owner to report the quantities of carbon dioxide emitted as a result of facility operation.

Analysis of Cumulative Impacts

Staff considers multiple issues related to the cumulative effects of the project. The first is the project's cumulative contribution to regional ambient concentrations of criteria pollutants that may violate air quality standards, taking into account the local air district's programmatic efforts to abate nonattainment conditions. Then the localized cumulative impacts of the proposed project are described quantitatively, considering other foreseeable local sources, and qualitatively for secondary pollutants.

The existing nonattainment conditions are described above and are similar to those at the time of the original decision (CEC 2003b). Compliance with the federal and California Clean Air Acts requires the SCAQMD to adopt, implement, and periodically update region-wide air quality management plans (AQMP) that specify the steps necessary to achieve attainment with ambient air quality standards. The AQMP includes baseline and future year emission inventories, population and economic growth projections, and control measures that enable the region to demonstrate future attainment. Programmatic control measures that are part of the attainment planning process in the AQMP include the NSR requirements to fully offset new emission increases of criteria pollutant emissions. As a result, compliance with the NSR and PSD permitting requirements identified by SCAQMD and adopted in the Energy Commission decision would ensure that project-related emissions occur in a manner that would be consistent with the management plans. By being consistent with the SCAQMD AQMP, the proposed project would not be likely to cause a significant regional cumulative impact.

Quantification of localized cumulative impacts is accomplished using a dispersion modeling approach identical to that used for routine operation impacts. The cumulative sources are: IEEC itself and the future projects (stationary sources) that are currently under construction or are currently under District review. Projects located up to six miles from IEEC were investigated, except for those with especially small sources (under 10 lb/day of emissions) that are not likely to notably affect overall concentrations.

The project owner gathered information from the SCAQMD on foreseeable future projects as of February 2005 and provided a cumulative air quality impacts analysis for the proposed amendment on April 4, 2005. The cumulative sources presently include one new internal combustion engine in Perris (at Pomeroy Corporation) and a boiler and concrete molding equipment in Romoland (at Orco Block, which would each emit less than 10 lb/day but were included because of their proximity) (IEEC 2005g).

The impacts associated with the cumulative sources would be nearly identical to those presented for routine operation of IEEC as shown in **Tables 8 and 9**, above. The project owner found that there would be very little overlap between the IEEC impacts and the impacts of the new cumulative sources (IEEC 2005g). Staff reviewed the dispersion modeling provided by the project owner for the cumulative analysis and agrees that no impact of any pollutant would change notably. This means that no additional mitigation would be necessary to respond to cumulative impacts.

MITIGATION

The original IEEC included design features to minimize emissions (emission control systems) and emission offsets, both required by SCAQMD rules and regulations, to reduce the potentially significant impacts (CEC 2003b). As with the original project, this amendment would also use emission control systems on each of the new sources and emission offsets in the form of RTCs, ERCs, or credits from the Priority Reserve program of SCAQMD Rule 1309.1. Since the original decision, the project owner has acquired additional ERCs to partially reduce the SOx liability. Staff recommends revising COC **AQ-SC9** to identify the new ERC. The remainder of project emissions would be fully offset as originally identified in **AQ-SC9**.

Staff recommends additional changes to mitigation to address emissions during commissioning and startups or shutdowns these emissions would need to be minimized to ensure that impacts would be reduced to less than significant levels. The additional mitigation would also ensure that the impacts described above have not been underestimated. Staff's proposed changes are described below.

Summary of Staff Changes to Mitigation

The recommended revisions to COCs include changes for the commissioning phase of the project to allow commissioning activities on one gas turbine unit simultaneously with baseload operation of the other (**AQ-SC13**). This condition is necessary and emission limitations should be established because commissioning would take longer than that proposed for the original project and simultaneous operation of the two units would be more likely. Staff also recommends changes to allow simultaneous startup of the two gas turbine units as long as new emission limits are not exceeded (**AQ-SC14**).

New mitigation has also been established with District conditions addressing the changed equipment, and District condition **AQ-2**, which requires a Memorandum of Understanding for establishing visibility baseline data at nearby Class I areas.

CONCLUSIONS

The requested changes in project design and construction would likely conform with applicable Federal, State, and SCAQMD air quality laws, ordinances, regulations, and standards, and the amended project would not be likely to cause significant air quality impacts, provided that the following Conditions of Certification are included. Staff recommends that the revised COCs be approved as shown below.

It is possible that after further review, the SCAQMD may revise the conditions with the Final Determination of Compliance, or that the SCAQMD and Energy Commission staff may find that revisions are necessary to address comments provided during the public review period, which for the SCAQMD ends in July 1, 2005. If necessary, a revision to this analysis would be prepared that provides any additional changes to the COCs.

PROPOSED CHANGES TO THE CONDITIONS OF CERTIFICATION

AQ-SC1 through **AQ-SC6 (Staff Conditions – Construction)** and **AQ-SC7** would remain as in the original decision (CEC 2003b).

All conditions pertaining to operation are reprinted here, with revisions and renumbering made necessary by the amendment.

Deleted text is shown in ~~strikethrough~~, added text **bold** and double **underlined**.

STAFF CONDITIONS – OPERATION

AQ-SC8 The project owner shall submit to the CPM and District Executive Officer Quarterly Operation Reports, no later than 30 days following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with Conditions **AQ-SC11**, **AQ-SC12**, **AQ-SC14**, **AQ-SC15**, **AQ-SC17**,and **AQ-1** through **AQ-57**, as applicable. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

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

AQ-SC9 The project owner shall provide emission reduction credits to offset turbine, ~~duct burner,~~ auxiliary boiler, and **standby/**emergency equipment NOx, CO, VOC, SOx, and PM_{10} emissions in the form and amount required by the District. RECLAIM Trading Credits (RTCs) shall be provided for NOx as necessary to demonstrate compliance with **AQ-27**, ~~and~~ **AQ-47, AQ-51, and AQ-52**. Emission reduction credits (ERCs) shall be provided for CO (~~823~~ **822** lb/day, includes offset ratio of 1.2) and VOC (~~340~~ **307** lb/day, includes offset ratio of 1.2). Emission reduction credits for SOx (~~81~~ **91** lb/day) and PM_{10} (~~504~~ **503** lb/day) shall be obtained from the SCAQMD Priority Reserve.

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

Prior to commencement of construction, the project owner shall obtain sufficient RTCs to satisfy the District's requirements for the first year of operation.

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

Pollutant	**Quantity**	**(units)**	**ERC# or Offset Strategy**
~~NOx~~	~~38,234~~	~~lb~~	~~2005-2010, Coastal, Zone 1~~
NOx	~~452,359~~ **322,988**	lb	2006-2010+, Coastal Zone 1, ~~Coastal~~ **Inland** Zone 2 (as listed in Ex. 2, p. 5.1-54.)
CO	677	lb/day	#AQ003178
CO	144	lb/day	#AQ004233
CO	3	lb/day	#AQ004222
CO	2	lb/day	#AQ004417
VOC	~~340~~**307**	lb/day	#AQ003069
PM10	~~504~~**503**	lb/day	Through Priority Reserve.
SOx	**14**	**lb/day**	**#AQ005311**
SOx	~~81~~**79**	lb/day	Through Priority Reserve.

Verification: The project owner shall submit to the CPM records showing that the project's offset requirements have been met 15 days prior to initiating construction for Priority Reserve credits **and RTCs**, and 30 days prior to turbine first fire for traditional ERCs. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC10 If the project owner uses Priority Reserve Credits to satisfy District ERC requirements, the project owner shall comply with all applicable requirements of SCAQMD Rule 1309.1 governing the use of such credits. Note: Nothing in this condition shall waive the requirements of Section 1720.3 of the Commission's regulations.

Verification: Within 15 days of becoming operational, the project owner shall submit to the District and CPM documentation substantiating that the requirements of SCAQMD Rule 1309.1 and Section 1720.3 of the Commission's regulations have been met.

AQ-SC11 The project owner shall perform quarterly cooling tower recirculating water quality testing **for each cooling tower**, or shall provide for continuous monitoring of conductivity as an indicator, for total dissolved solids content. The project owner shall also provide ~~a~~ flow meter**s** to determine the daily cooling tower circulating water flow **for each cooling tower**.

Verification: The project owner shall submit to the CPM cooling tower recirculating water quality tests or a summary of continuous monitoring results and daily recirculating water flow in the Quarterly Operation Report (**AQ-SC8**). If the project owner uses continuous monitoring of conductivity as an indicator for total dissolved solids content, the project owner shall submit data supporting the calibration of the conductivity meter and the correlation with total dissolved solids content at least once each year in a Quarterly Operation Report (**AQ-SC8**).

AQ-SC12 The cooling tower daily PM_{10} emissions shall be limited to ~~79~~ **42** lb/day **per cooling tower**. ~~The~~ **Each** cooling tower shall be equipped with a drift eliminator to control the drift fraction to 0.0005 percent of the circulating water flow. The project owner shall estimate daily PM_{10} emissions from ~~the~~ **each** cooling tower using the water quality testing data or continuous monitoring data and daily circulating water flow data collected on a quarterly basis.

Verification: The project owner shall submit to the CPM daily cooling tower PM_{10} emission estimates in the Quarterly Operation Report (**AQ-SC8**).

AQ-SC13 The project owner shall minimize emissions of carbon monoxide and nitrogen oxides from the gas turbines ~~and duct burners~~ to the maximum extent possible during the commissioning period. **During the commissioning period, the project owner shall limit the combined CO emission rate for the two gas turbines to 794.2 lb/hr (777 lb/hr commissioning plus 17.2 lb/hr baseload) and limit the combined NOx emission rate for the two gas turbines to 605.8 lb/hr (587 lb/hr commissioning plus 18.8 lb/hr baseload)** ~~Commissioning tests for one gas turbine shall not be conducted simultaneously with commissioning tests for the other.~~

Verification: See the verification for Condition **AQ-17**.

AQ-SC14 The project owner shall limit emissions during startup periods**. During startup periods,** ~~so that~~ **the project owner shall limit the combined CO emission rate for the two gas turbines to 190 lb/hr (95 lb/hr for each) and limit the combined NOx emission rate for the two gas turbines to 816 lb/hr (408 lb/hr for each)**~~startup of a gas turbine shall only occur when the other turbine is not in a startup mode~~.

Verification: See the verification for Condition **AQ-~~17~~18**.

AQ-SC15 The gas turbines ~~and duct burners~~ shall be fired on natural gas that results in emissions of less than 1.8**3** lb/hr SOx for each gas turbine ~~and duct burner pair~~, averaged over three hours.

Verification: The project owner shall compile hourly SOx emissions data for each gas turbine ~~and duct burner pair~~. The hourly emission data shall be calculated using the emission factor specified in Condition **AQ-13**. The emissions data shall be submitted to the CPM in the Quarterly Operation Report (**AQ-SC8**).

AQ-SC16 The project owner shall install and operate the equipment so that it does not exceed the emission limits set forth in the Equipment Description portion of Section H of the facility permit issued by the District. The current Equipment Description, as shown in the ~~Addendum to the Final~~ **May 2005** Determination of Compliance, is attached as **Attachment Air Quality 1 – AQ-SC16, Equipment Description**.

Verification: The project owner shall submit to the CPM emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report

(**AQ-SC8**). The project owner shall submit to the CPM all permit changes, whether initiated by the project owner or the District, pursuant to Condition **AQ-SC7**.~~g~~

AQ-SC17 The project owner shall report to the CPM the quantity of CO_2 emitted on an annual basis as a direct result of facility electricity production.

Verification: Any CO_2 emissions that are reported by the project owner to the California Climate action Registry or pursuant to this condition shall be reported to the CPM at least once each year in a Quarterly Air Quality Report (AQ-SC8).

DISTRICT CONDITIONS – DETERMINATION OF COMPLIANCE

Facility Conditions

AQ-1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition. (SCAQMD F9-1)

Verification: The project owner shall document any known opacity violations in the Quarterly Operation Report (**AQ-SC8**). The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-2 ~~The operator shall not use diesel fuel containing sulfur compounds in excess of 0.05 percent by weight. (SCAQMD F14-1)~~**The equipment is subject to the applicable requirements of the following rules or regulations:**

Within 6 months of permit issuance, the facility will sign a Memorandum of Understanding with the U.S. Forest Service to participate in a visibility monitoring project, the results of which will be used to establish a visibility baseline in nearby Class 1 Areas. (SCAQMD E193-3)

Verification: The project owner shall make ~~fuel purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content~~ **the U.S. Forest Service Memorandum of Understanding** available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-3 The operator shall not purchase **or burn** diesel oil containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

~~This condition shall become effective on or after June 1, 2004.~~ (SCAQMD F14-~~2~~**1**)

Verification: The project owner shall make fuel oil purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-4 Accidental release prevention requirements of Section 112(r)(7):

a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the SCAQMD Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b). The operator shall submit any additional relevant information requested by the Executive Officer or designated agency. (SCAQMD F24-1)

Verification: The project owner shall submit to the District and the CPM the documents listed above as part of an annual compliance certification.

Gas Turbines~~, Duct Burners,~~ and SCR

Conditions of Certification AQ-5 through AQ-28 apply individually to each turbine/HRSG unit unless otherwise identified.

AQ-5 The operator shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-1)

Verification: The project owner shall make the site available for inspection of the ammonia flow meter and ammonia flow records by representatives of the District, CARB and the Commission.

AQ-6 The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-2)

Verification: The project owner shall make the site available for inspection of the temperature gauge on the inlet to the SCR and the continuous temperature records by representatives of the District, CARB and the Commission.

AQ-7 The operator shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-3)

Verification: The project owner shall make the site available for inspection of the SCR catalyst bed differential pressure gauge and the differential pressure records by representatives of the District, CARB and the Commission.

AQ-8 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NO_x emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ **VOC** emissions	Approved District Method	1 hour	Outlet of the SCR
PM emissions	Approved District Method	District Approved Averaging Time	Outlet of the SCR
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the **gas** turbine**s** ~~and steam turbine~~ generating output in MW.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

~~The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.~~ For natural gas fired turbines only **the VOC test shall use**~~, this shall be demonstrated by~~ the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F.

The use of this alternative **VOC test** method ~~does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval, except~~ **is solely** for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits.

The test shall be conducted ~~with and without duct firing~~ when this equipment is operating at loads of 100, 75, and 50 percent of maximum load for the NO_x, CO, ~~ROG~~ **VOC, PM,** and ammonia tests.~~ For all other pollutants, the test shall be conducted with and without duct firing at 100% load only.~~ (SCAQMD **D**29-1)

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

AQ-9 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ **VOC** emissions	Approved District Method	1 hour	Outlet of the SCR
PM emissions	Approved District Method	District Approved Averaging Time	Outlet of the SCR

The test(s) shall be conducted at least once every three years.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted ~~1) when the gas turbine and the duct burners are operating simultaneously at 100 percent of maximum heat input and 2)~~ when the gas turbine is operating ~~alone~~ at 100 percent of maximum heat input.

~~The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.~~ For natural gas fired turbines only, **the VOC test shall use** ~~this shall be demonstrated by~~ the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F.

The use of this alternative method **<u>is solely</u>** ~~does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval, except~~ for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit. (SCAQMD **<u>D</u>**29-2)

<u>Verification:</u> The project owner shall submit the proposed protocol for the triennial source tests 45 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-10 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit. (SCAQMD **<u>D</u>**29-3)

<u>Verification:</u> The project owner shall submit the proposed protocol for the ammonia slip source tests 30 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than ten days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

AQ-11 The operator shall provide to the District a source test report (see **AQ-8**, **AQ-9**, and **AQ-10**)in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF **and in terms of lbs/MMBtu**.

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted. (SCAQMD **K**40-1)

Verification: See verifications for Conditions **AQ-8**, **AQ-9**, and **AQ-10**.

AQ-12 The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample of natural gas composition **or gas supplier documentation**. (SCAQMD **B**61-1)

Verification: The project owner shall submit to the CPM and APCO turbine fuel data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-13 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	**9,728**~~9,960~~ LBS IN ANY 1 MONTH
PM_{10}	7,440 LBS IN ANY 1 MONTH
~~ROG~~ **VOC**	**3,769**~~4,188~~ LBS IN ANY 1 MONTH
SO_x	**1,362**~~1,197~~ LBS IN ANY 1 MONTH

For the purpose of this condition, the limits shall be based on the ~~combined~~ emissions from each gas turbine ~~and its associated duct burners~~.

The operator shall calculate the emissions by using monthly fuel use data and the following emission factors: PM_{10} ~~with duct burners firing 4.23~~**3.91** lbs/mmscf, ~~PM_{10} without duct burners firing 5.01 lbs/mmscf, ROG~~ **VOC** ~~with duct burners firing 2.55~~**1.79** lbs/mmscf, ~~ROG without duct burners firing 1.41 lbs/mmscf,~~ SO_x 0.71 lbs/mmscf ~~with and without duct burner firing~~.

The operator shall calculate the emissions for CO, during the commissioning period, using fuel consumption data and the following emission factor: ~~127.87~~**22.19** lb/mmscf.

~~The operator shall calculate the emissions for CO, after the commissioning period and prior to the CO CEMS certification, using fuel consumption data and the following emission factor: 19.76 lbs/mmscf.~~

The operator shall calculate the emissions for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan. (SCAQMD **A**63-1)

Verification: The project owner shall submit to the CPM and APCO turbine emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-14 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period. (SCAQMD **K**67-1)

Verification: The project owner shall make the site available for inspection of the commissioning period natural gas usage data by representatives of the District, CARB and the Commission.

AQ-15 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv.

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.

The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period.

The CEMS shall be installed and **in operation and Rule 218 testing submitted to the AQMD at the conclusion of the turbine commissioning period prior to base load commercial operation** ~~operating no later than 90 days after initial startup of the turbine~~. (SCAQMD **D**82-1)

Verification: The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-16 The operator shall install and maintain a CEMS to measure the following parameters:

NO_x concentration is expressed in ppmv.

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 12 months after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine startup date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be in operation and Rule 2012 provisional RATA testing submitted to the AQMD at the conclusion of the turbine commissioning period prior to base load commercial operation. (SCAQMD **D**82-2)

Verification: The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-17 The **68.26 lbs/mmscf** ~~2.0 ppm~~ NO_x emission limit(s) shall ~~not~~ **only** apply during turbine commissioning~~, startup, and shutdown periods~~. ~~Startup/shutdown time shall not exceed four hours per day per gas turbine. The commissioning period per gas turbine shall not exceed 636 operating hours from the date of initial start-up. The operator shall provide the AQMD with written notification of the start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD~~. (SCAQMD **A**99-1)

Verification: The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with this condition and the emission limits of Condition **AQ-13**. The monthly commissioning status report shall include criteria pollutant emission estimates for each commissioning activity and total commissioning emission estimates. The monthly commissioning status report shall be submitted to the CPM until the report includes the completion of the initial commissioning activities. ~~The project owner shall provide start-up and shutdown~~

~~occurrence and duration data as part as part of the Quarterly Operation Report (**AQ-SC8**).~~ The project owner shall make the site available for inspection of the commissioning ~~and start-up/shutdown~~ records by representatives of the District, CARB and the Commission.

AQ-18 The operator shall operate and maintain this equipment according to the following requirements:

The commissioning period shall not exceed 509 hours of operation for both turbines during the first 180 calendar days from the date of initial start-up.

Startup/shutdown time shall not exceed 4 hours per day per gas turbine, except for a cold startup which shall not exceed 6 hours per day per gas turbine. For purposes of this condition a cold startup shall be defined as a startup of the gas turbine after 72 hours of non-operation.

Startup emissions shall not exceed 125 lbs/hr NOx and 50 lbs/hr CO averaged for the duration of the startup.

Monthly startup/shutdown time shall not exceed 31 hours. Shutdown time does not include non-operation time.

The operator shall provide the AQMD with written notification of the initial startup date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD. (SCAQMD E193-2)

~~**AQ-18** The 3.0 ppm CO emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. Startup/shutdown time shall not exceed four hours per day per gas turbine. The commissioning period per gas turbine shall not exceed 636 operating hours from the date of initial start-up. The operator shall provide the AQMD with written notification of the initial start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD. (SCAQMD 99-2)~~

Verification: ~~See verification of Condition **AQ-17**.~~ **The project owner shall submit to the CPM the final commissioning status report as in Condition AQ-17. The project owner shall provide startup and shutdown occurrence, duration, and emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall make the site available for inspection of the commissioning and start-up/shutdown records by representatives of the District, CARB and the Commission.**

AQ-19 The ~~14.03~~ **7.36** lbs/mmscf NO_x emission limit(s) shall only apply during the interim **reporting** period ~~to report RECLAIM emissions. The interim period shall not exceed 12 months from the initial startup date~~**after the commissioning period**. (SCAQMD **A**99-3)

Verification: The project owner shall submit to the CPM and APCO turbine emissions data demonstrating compliance with this condition through the use of the required RECLAIM emission factor, as appropriate, as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-20 For the purpose of the following conditions continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. **(SCAQMD E179-1)**

Condition **AQ-5 (SCAQMD D12-1)**

Condition **AQ-6** (SCAQMD ~~179-1~~**D12-2**)

Verification: See verifications for Conditions **AQ-5** and **AQ-6**.

AQ-21 For the purpose of the following condition continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month. **(SCAQMD E179-2)**

Condition **AQ-7** (SCAQMD ~~179-2~~**D12-3**)

Verification: See verification for Condition **AQ-7**.

AQ-22 The 2.0 ppmv NO_x emission limit is averaged over 1 hour at 15 percent oxygen, dry basis. The limit shall not apply to **turbine commissioning, startup and shutdown periods. The limit shall not apply to** the first fifteen 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, in any rolling 12-month period for each combustion gas turbine provided that it meets all of the following requirements:

A. This equipment operates under any one of the qualified conditions described below:

a) Rapid combustion turbine load changes due to the following conditions:
- Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control; or
- Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load

b) The first two 1-hour reporting periods following the initiation/shutdown of a ~~fogging~~ **inlet air cooling** system injection pump

~~c) The first two 1-hour reporting periods following the initiation/shutdown of combustion turbine steam injection~~

~~d) The first two 1-hour reporting periods following the initiation of HRSG duct burners~~

e) Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees

B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).

C. The qualified operating conditions described in (A) above are recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the date and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1-hour average limit.

D. The 1-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O2.

All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit. (SCAQMD **A**195-1)

Verification: The project owner shall submit to the CPM and APCO turbine CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-23 The 3.0 ppmv CO emission limit is averaged over 1 hour at 15 percent oxygen~~, dry basis when the HRSG duct burners are not operating. The 4.0 ppmv CO emission limit is averaged over 1 hour at 15 percent oxygen, dry basis when the HRSG duct burners are operating~~**, This limit shall not apply to turbine commissioning, startup and shutdown periods**. (SCAQMD **A**195-2)

Verification: The project owner shall submit to the CPM and APCO turbine CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-24 The 2.0 ppmv ~~ROG~~ **VOC** emission limit is averaged over 1 hour at 15 percent oxygen, dry basis. **This limit shall not apply to turbine commissioning, startup and shutdown periods.** (SCAQMD **A**195-3)

Verification: See verifications for Conditions **AQ-8** and **AQ-9**.

AQ-25 The 5 ppmv NH_3 emissions limit is averaged over 1 hour at 15 percent oxygen, dry basis. (SCAQMD **A**195-~~6~~**7**)

Verification: See verification for Conditions **AQ-8**, **AQ-10**, and **AQ-26**.

AQ-26 The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 15% oxygen. It shall continuously monitor or calculate, and record the following parameters:

- Ammonia concentration, uncorrected in ppmv
- Oxygen concentration in percent
- Ammonia concentration in ppmv, corrected to 15% oxygen
- Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 15% oxygen

The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the **AQMD** Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once ~~an exceedance~~ **a violation** has occurred.

The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.

The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the turbine. (SCAQMD **D**232-1)

Verification: The project owner shall provide the CPM documentation of the District's approval of the continuous emission monitoring device, within 15 days of its receipt. The project owner shall make the site available for inspection of the monitoring device and monitoring device records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the continuous emission monitoring device as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-27 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 159,163 lbs for the initial gas turbine plus 135,754 lbs for the second gas turbine. This condition shall apply during the first twelve months of operation, commencing with the initial operation of each gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 159,069 lbs for each gas turbine. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD **I**296-1 **and I296-2**)

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-28 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time. (SCAQMD **A**327-1)

Verification: See verifications for Conditions **AQ-8** and **AQ-9**.

Auxiliary Boiler and SCR

AQ-29 The operator shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-1)

Verification: The project owner shall make the site available for inspection of the ammonia flow meter and ammonia flow records by representatives of the District, CARB and the Commission.

AQ-30 The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-2)

Verification: The project owner shall make the site available for inspection of the temperature gauge on the inlet to the SCR and the continuous temperature records by representatives of the District, CARB and the Commission.

AQ-31 The operator shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD **D**12-3)

Verification: The project owner shall make the site available for inspection of the SCR catalyst bed differential pressure gauge and the differential pressure records by representatives of the District, CARB and the Commission.

AQ-32 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NO_x emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ **VOC** emissions	Approved District Method	1 hour	Outlet of the SCR
PM emissions	Approved District Method	District Approved Averaging Time	Outlet of the SCR

NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the auxiliary boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 percent of maximum load for the NOx, CO, ~~ROG~~ **<u>VOC, PM,</u>** and ammonia tests. ~~For all other pollutants, the test shall be conducted at 100% load only.~~ (SCAQMD **<u>D</u>**29-~~1~~**<u>4</u>**).

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

AQ-33 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NO_x concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NO_x emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit. (SCAQMD **<u>D</u>**29-3)

Verification: The project owner shall submit the proposed protocol for the source tests 30 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than ten days prior to the proposed source test date and time. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.

AQ-34 The operator shall provide to the District a source test report (see **AQ-32** and **AQ-33**) in accordance with the following specifications:

- Source test results shall be submitted to the District no later than 60 days after the source test was conducted.
- Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.
- All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).
- All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.
- Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted. (SCAQMD **K**40-2)

Verification: See verifications for Conditions **AQ-32** and **AQ-33**.

AQ-35 ~~Reserved~~**The operator shall limit the fuel usage to no more than 92.844 mmscf per year**.

To comply with this condition, the operator shall install and maintain a non-resetable totalizing fuel meter to accurately indicate the fuel usage of the auxiliary boiler. (SCAQMD C1.2)

Verification: ~~Reserved.~~ **The project owner shall submit to the CPM and APCO the auxiliary boiler operations data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall make the auxiliary boiler available for inspection by representatives of the District, CARB and the Commission upon request.**

AQ-36 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	~~667~~ **1,113** LBS IN ANY 1 MONTH
PM_{10}	~~233~~ **218** LBS IN ANY 1 MONTH

~~ROG~~ **VOC**	~~127~~ **90** LBS IN ANY 1 MONTH
SO_x	~~19~~ **21** LBS IN ANY 1 MONTH

The operator shall calculate the emissions by using monthly fuel use data and the following emission factors: CO ~~21.72~~**36.92** lb/mmscf, PM_{10} ~~7.58~~ **7.26** lbs/mmscf, ~~ROG~~ **VOC 4.22**~~4.14~~ lbs/mmscf, SO_x ~~0.70~~**0.71** lbs/mmscf.

The operator shall calculate the emissions for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan. (SCAQMD **A**63-2)

Verification: The project owner shall submit to the CPM and APCO boiler emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-37 The operator shall install and maintain a CEMS to measure the following parameters:

- CO concentration in ppmv.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.

The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period.

The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler. (SCAQMD **D**82-3)

Verification: The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-38 The operator shall install and maintain a CEMS to measure the following parameters:

- NO_x concentration is expressed in ppmv.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 12 months after initial start-up of the boiler and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the boiler startup date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be in operation and Rule 2012 provisional RATA testing submitted to the AQMD at the conclusion of the turbine commissioning period prior to base load commercial operation.

The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler. (SCAQMD **D**82-4)

Verification: The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-39 The ~~8.36~~**8.49** lbs/mmscf NO_x emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. ~~The interim reporting period shall not exceed 12 months from the initial startup date.~~ (SCAQMD **A**99-~~4~~**2**)

Verification: The project owner shall submit to the CPM and APCO auxiliary boiler emissions data demonstrating compliance with this condition through the use of the required RECLAIM emission factor, as appropriate, as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-40 For the purpose of the following conditions continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. **(SCAQMD E179-1)**
Condition **AQ-29** **(SCAQMD D12-1)**
Condition **AQ-30** (SCAQMD ~~179-1~~**D12-2**)

Verification: See verifications for Conditions **AQ-29** and **AQ-30**.

AQ-41 For the purpose of the following condition continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month. **(SCAQMD E179-2)**

Condition **AQ-31** (SCAQMD ~~179-2~~**D12-3**)

Verification: See verification for Condition **AQ-31**.

AQ-42 The 7 ppmv NO_x emission limit(s) are averaged over one hour at 3 percent oxygen, dry basis. (SCAQMD **A**195-4)

Verification: The project owner shall submit to the CPM and APCO auxiliary boiler CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-43 The 50 ppmv CO emission limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis. (SCAQMD **A**195-5)

Verification: The project owner shall submit to the CPM and APCO auxiliary boiler CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

~~**AQ-44 The 10 ppmv VOC emission limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis. (SCAQMD A195-6)**~~

~~**Verification: See verification for Condition AQ-32.**~~

AQ-45 The 5 ppmv NH3 emission limit(s) are averaged over 1 hour at 3 percent oxygen, dry basis. (SCAQMD **A**195-~~7~~**8**)

Verification: See verification for Conditions **AQ-32**, **AQ-33**, and **AQ-46**.

AQ-46 The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 3% oxygen. It shall continuously monitor or calculate, and record the following parameters:

- Ammonia concentration, uncorrected in ppmv
- Oxygen concentration in percent
- Ammonia concentration in ppmv, corrected to 3 percent oxygen
- Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 3 percent oxygen

The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the **AQMD** Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once ~~an exceedance~~**a violation** has occurred.

The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.

The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the boiler. (SCAQMD **D**232-2)

Verification: The project owner shall provide the CPM documentation of the District's approval of the continuous emission monitoring device, within 15 days of its receipt. The project owner shall make the site available for inspection of the monitoring device and monitoring device records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the continuous emission monitoring device as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-47 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 786 lbs. This condition shall apply during the first twelve months of operation.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 786 lbs. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD **I**296-~~1~~**3**)

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

Two Emergency Generator Engines and One Fire Pump Engine

Conditions of Certification AQ-48 through AQ-55 apply separately to ~~the~~ each emergency generator and fire pump engine, unless otherwise specified.

AQ-48 The operator shall limit the operating time of ~~the~~ **each** engine to no more than ~~200~~ **50** hours per year. (SCAQMD **C**1-1)

Verification: The project owner shall submit to the CPM and APCO the emergency generator and fire pump IC engines operations data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-49 The operator shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of ~~the~~ **each** engine. (SCAQMD **D**12-4)

Verification: The project owner shall make the emergency generator and fire pump engine**s** available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-50 The operator shall install and maintain a non-resetable elapsed fuel meter to accurately indicate the engine fuel consumption. (SCAQMD **D**12-5)

Verification: The project owner shall make the emergency generator and fire pump engine**s** available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-51 **The emergency generator engines shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.**

To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 1,946 lbs for each engine. This condition shall apply during the first twelve months of operation.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 1,946 lbs for each engine. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-4)

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).

AQ-52 **The fire pump engine shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.**

To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 172 lbs. This condition shall apply during the first twelve months of operation.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 172 lbs. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-5)

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).

AQ-53 The operator shall keep records, in a manner approved by the District, for the following parameters or items:

- Date of operation, the elapsed time, in hours, and the reason for operation.

- Records shall be kept and maintained on file for a minimum of two years and made available to district personnel upon request. (SCAQMD **K**67-2)

Verification: The project owner shall make the emergency generator and fire pump engine records available for inspection by representatives of the District, CARB and the Commission upon request.

Ammonia Storage Tanks

AQ-54 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled. (SCAQMD ~~144~~**E141**-1)

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

AQ-55 The operator shall install and maintain a pressure relief valve set at 25 psig. (SCAQMD **C**157-1)

Verification: The project owner shall make the ammonia tank pressure relief valve and its specifications available for inspection by representatives of the District, CARB and the Commission upon request.

Organic Materials

AQ-56 The operator shall be subject to the applicable requirements of District Rule 1171 for VOC control from Solvent Cleaning Operations. This requirement shall apply to Rule 219 Exempted Cleaning Equipment. (SCAQMD **H**23-1)

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

AQ-57 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

- For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records for all coating consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvent, for other coatings.

- For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

- This requirement shall apply to Rule 219 Exempted Coating Equipment. (SCAQMD **K**67-3)

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

ATTACHMENT AIR QUALITY 1 – AQ-SC16, EQUIPMENT DESCRIPTION

[Following is a copy of Equipment Description from the Determination of Compliance, filed by SCAQMD, distribution date May 17, 2005.]

EQUIPMENT DESCRIPTION

Section H of the facility permit: Permit to Construct and temporary Permit to Operate

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 1: COMBUSTION AND POWER GENERATION					
SYSTEM 1: GAS TURBINE COMBUSTION					
TURBINE, #1, NATURAL GAS, GENERAL ELECTRIC, MODEL 107H, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, 2,597 MMBtu/HR (at 36 ºF) WITH: A/N: 439481 GENERATOR, 405 MW GENERATOR, #1, HEAT RECOVERY STEAM GENERATOR (HRSG)	D1 B11 B13	C17	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT, RULE 1703]; NOx: (COMMISSIONING) 68.26 LBS/MMSCF (1) [RULE 2012]; NOx: 7.36 LBS/MMSCF (1) [RULE 2012]; NOx: 180 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; VOC: 1.4 PPMV (7) [RULE 1303-OFFSET] **PM10**: 10.0 LBS/HR (4) [RULE 1303-BACT]; PM10: 0.1 GR/SCF (5) [RULE 409]; PM10: 11 LBS/HR (5) [RULE 475]; PM10: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG]; SO2: (9) [40CFR 72 – ACID RAIN]; H_2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	A63.1, A99.1, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D29.1, D29.2, D82.1, D82.2, E193.1, E193.2, E193.3, I296.1, K40.1, K67.1
CO OXIDATION CATALYST #1, ENGELHARD, HEIGHT:	C17	C4, D1,			

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
64'8", WIDTH: 33', CATALYST VOLUME: 290 FT^3, SERVING TURBINE/HRSG #1, WITH: A/N: 439488					
SELECTIVE CATALYTIC REDUCTION, #1, HALDER-TOPSOE, , HEIGHT: 64'8", WIDTH: 33', CATALYST VOLUME: 2,048 FT^3, SERVING TURBINE/HRSG #1, WITH: A/N:439488 AMMONIA INJECTION, INJECTION GRID	C4 B18	C17		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT]	A195.7, D12-1, D12.2, D12.3, D29.3, D232.1, E179.1, E179.2 E193.3,
STACK, #1 SERVING TURBINE AND HRSG #1, HEIGHT: 195 FT; DIAMETER: 22 FT, WITH: A/N: 439481	S19	C4			
TURBINE, #2, NATURAL GAS, GENERAL ELECTRIC, MODEL 107H, COMBINED CYCLE, WITH DRY LOW NOx BURNERS, 2,597 MMBtu/HR (at 36 ºF) WITH: A/N: 439485 GENERATOR, 405 MW GENERATOR, #2, HEAT RECOVERY STEAM GENERATOR (HRSG)	D2 B20 B22	C18	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT, RULE 1703]; NOx: (COMMISSIONING) 68.26 LBS/MMSCF (1) [RULE 2012]; NOx: 7.36 LBS/MMSCF (1) [RULE 2012];NOx: 180 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; VOC: 1.4 PPMV (7) [RULE 1303-OFFSET] **PM10**: 10.0 LBS/HR (4) [RULE 1303-BACT]; PM10: 0.1 GR/SCF (5) [RULE 409]; PM10: 11 LBS/HR (5) [RULE 475]; PM10: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG]; SO2: (9) [40CFR 72 –	A63.1, A99.1, A99.3, A195.1, A195.2, A195.3, A327.1, B61.1, D29.1, D29.2, D82.1, D82.2, E193.1, E193.2, E193.3, I296.2, K40.1, K67.1

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	
CO OXIDATION CATALYST #2, ENGELHARD, HEIGHT: 64'8", WIDTH: 33', CATALYST VOLUME: 290 FT^3, SERVING TURBINE/HRSG #2, WITH: A/N: 439489	C18	D2, C5			
SELECTIVE CATALYTIC REDUCTION, #2, HALDER-TOPSOE, , HEIGHT: 64'8", WIDTH: 33', CATALYST VOLUME: 2,048 FT^3, SERVING TURBINE/HRSG #2, WITH : A/N: 439489 AMMONIA INJECTION, INJECTION GRID	C5 B25	C18		**NH3**: 5 PPMV (4) [RULE 1303-BACT]	A195.7, D12-1, D12.2, D12.3, D29.3, D232.1, E179.1, E179.2 E193.3,
STACK, #2, SERVING TURBINE AND HRSG #2, HEIGHT: 195 FT, DIAMETER: 22 FT A/N: 439485	S26	C5			
SYSTEM 2: AUXILIARY EQUIPMENT					
BOILER, AUXILIARY, NEBRASKA BOILER, MODEL NS-F-76, NATURAL GAS FIRED, 157 MMBtu/HR, WITH: A/N: 439492 BURNER, NATURAL GAS, TBD	D3	C6	NOx MAJOR SOURCE	**NOx**: 7.0 PPMV (4) [RULE 2005 BACT, RULE1703]; NOx: 8.36 LBS/MMSCF (1) [RULE 2012]; **CO**: 50 PPMV (4) [RULE 1303 BACT]; CO: 400 PPMV (5) [RULE 1146]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 10 PPMV (4) [RULE 1303 BACT] **PM10**: 7.26 LBS/HR (4) [RULE 1303-BACT]; PM10: 0.1 GR/SCF (5) [RULE 409];	A63.2, A99.2, A195.4, A195.5, A195.6, B61.1, C1.2, D29.4, D82.3, D82.4, E193.1, E193.3, I296.3, K40.2
SELECTIVE CATALYTIC REDUCTION, #3, PEERLESS, HEIGHT: 7'4", LENGTH: 4'3", WIDTH: 4', VOL: 115 FT^3, SERVING AUXILIARY	C6	D3		**NH3**: 5 PPMV (4) [RULE 1303-BACT]	A195.8, D12-1, D12.2, D12.3, D29.3,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
BOILER, WITH: A/N:439493 AMMONIA INJECTION, INJECTION GRID	 B25				D232.2, E179.1, E179.2 E193.3,
STACK, HEIGHT: 100 FT; DIA: 4 FT, SERVING AUXILIARY BOILER, WITH: A/N:439492	S31	C6			
IC ENGINE, EMERGENCY #1, DIESEL, CATERPILLAR, MODEL G3516BDITA, 2,848 HP, WITH PERMIT FILTER, WITH: A/N: 439494 GENERATOR: 2,000 KW	D9		NOx: PROCESS UNIT	**NOx**: 6.2 G/BHP-HR (4) [RULE 2005, RULE 1703]; NOx: 270 LB/1000 GAL (1) [RULE 2012]; **CO**: 0.045 G/BHP-HR (4) [RULE 1303]; **VOC**: 0.03 G/BHP-HR (4) [RULE 1303] **PM10**: 0.015 G/BHP-HR (4) [RULE 1303]	C1.1, D12.4, D12.5, K67.2, E193.1, E193.3, I296.4
IC ENGINE, EMERGENCY #2, DIESEL, , CATERPILLAR, MODEL G3516BDITA, 2,848 HP, WITH PERMIT FILTER, WITH: A/N: 439495 GENERATOR: 2,000 KW	D10		NOx: PROCESS UNIT	**NOx**: 6.2 G/BHP-HR (4) [RULE 2005, RULE 1703]; NOx: 270 LB/1000 GAL (1) [RULE 2012] **CO**: 0.045 G/BHP-HR (4) [RULE 1303] **VOC**: 0.03 G/BHP-HR (4) [RULE 1303] **PM10**: 0.015 G/BHP-HR (4) [RULE 1303]	C1.1, D12.4, D12.5, K67.2, E193.1, E193.3, I296.4
EMERGENCY FIRE PUMP, DIESEL, IC ENGINE, CLARKE, MODEL JW6H-UF40, 300 HP, WITH: A/N: 439496	D32		NOx: PROCESS UNIT	**NOx**: 5.2 G/BHP-HR (4) [RULE 2005, RULE 1703]; NOx: 240 LB/1000 GAL (1) [RULE 2012]; **CO**: 0.3 G/BHP-HR (4) [RULE 1303] **VOC**: 0.2 G/BHP-HR (4) [RULE 1303] **PM10**: 0.1 G/BHP-HR (4) [RULE 1303]	C1.1, D12.4, D12.5, K67.2, E193.1, E193.3, I296.5
STORAGE TANK, #1, WITH A	D7				E144.1,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. WITH: A/N: 439497					C157.1, E193-1 E193.3,
STORAGE TANK, #2, WITH A VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. WITH: A/N: 439498	D8				E144.1, C157.1, E193-1, E193.3,
PROCESS 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE-SPECIFIC RULE					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, ARCHITECTURE COATINGS	E			VOC: (9) [RULE 1113, 5-4-1999; RULE 1171, 6-13-1997]	K67.3
RULE 219 EXEMPT CLEANING EQUIPMENT USING SOLVENTS	E			VOC: (9) [RULE 1171, 6-13-1997]	H23.1

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BIOLOGICAL RESOURCES ANALYSIS

NATASHA NELSON

SUMMARY OF ANALYSIS

On March 11, 2005 Inland Empire Energy Center LLC submitted Amendment No. 1 to their project as described in the Commission Decision (IEEC 2005). The project owner requests several changes to their project, but most are equipment related. Biological resource impacts are only expected from the project owner's requests to install a different type of turbine and to add two additional laydown areas.

Staff has reviewed the Amendment materials, the Commission Decision for the original Inland Empire Energy Center (01-AFC-17) dated December 22, 2003 (CEC 2003c), the Staff Assessment for that AFC dated May 23, 2003 (CEC 2003a) and the Addendum to the Staff Assessment dated July 18, 2003 (CEC 2003b). Staff has further reviewed any changes in laws, ordinances, regulations and standards (LORS), the environment, and the project. Based upon review of these materials, staff concludes the only biological resources impact is temporary disturbance to potential Stephens' kangaroo rat habitat. To offset impacts to Stephens' kangaroo rat habitat, the project owner proposes to increase the amount of mitigation land purchased through an existing fee structure. The project will comply with all LORS provided the Condition of Certification **BIO-11** (relating to mitigation land) is adopted as modified as part of the final Energy Commission Decision on Amendment 1.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The LORS referenced in the Final Staff Assessments (May 2003, July 2003) and the Commission Decision (December 2003) are applicable to this proposed amendment, and there are no additional LORS. Amendment 1 was reviewed for consistency against three local ordinances that address habitat disturbance (see analysis below). Staff discovered Riverside County Ordinance No. 810 has been amended since release of the Staff Assessment and the Addendum to the Staff Assessment, and an update to this Ordinance is presented as part of this testimony.

STEPHENS' KANGAROO RAT HABITAT CONSERVATION PLAN (HCP)

The Stephens' kangaroo rat HCP is a 30-year plan approved in 1996 that is designed to acquire and permanently set-aside, maintain, manage and fund conservation, preservation, restoration and enhancement of the Stephens' kangaroo rat and its habitat. The HCP establishes suitable habitat areas where incidental take is permitted through a fee process and core reserve areas in occupied habitat where individual permits are required. The HCP and the creation of a designated fee area establishes a regional mechanism in western Riverside County through which otherwise lawful activities resulting in the incidental take of Stephens' kangaroo rat meet the federal Endangered Species Act and California Endangered Species Act requirements without the need to secure individual permits and agreements from the USFWS and the CDFG. All of the IEEC project features and the Amendment 1 laydown area are located within the Stephens' kangaroo rat HCP fee area.

RIVERSIDE COUNTY ORDINANCE NO. 663.10, STEPHENS' KANGAROO RAT MITIGATION FEE ORDINANCE

The ordinance establishes a Plan Fee Assessment Area and sets mitigation fees for development permits in areas covered by the Stephens' Kangaroo Rat Habitat Conservation Plan. Prior to issuance of a grading permit, the IEEC shall comply with the provisions of this ordinance, which generally requires the payment of the appropriate fee set forth in that ordinance. The amount of the fee to be paid may vary depending on the type of development application submitted and the applicability of any fee reduction or exemption provisions contained in the ordinance. However, generally all applicants who cannot satisfy mitigation through onsite measures shall pay a fee of $500.00 per gross acre of the parcels proposed for development. Amendment 1 must comply with the Ordinance No. 663.10 as part of Condition of Certification **BIO-11**, as amended.

RIVERSIDE COUNTY ORDINANCE NO. 810 AS AMENDED WITH ORDINANCE NO. 810.2, ESTABLISHING AN INTERIM OPEN SPACE MITIGATION FEE

The ordinance establishes and sets forth policies, regulations, and a fee to fund the acquisition of open space and preservation of habitat for wildlife necessary to mitigate the direct and cumulative environmental effects generated by new development projects described and defined in this ordinance. Fees are established for projects in residential, commercial and industrial areas that fall within the fee area boundaries. The amount of the fee shall be calculated on the basis of the current rates for industrial projects and the "Project Area", which shall mean the area, measured in acres, from the adjacent road right-of-way to the limit of the project development. Since release of the Staff Assessment and the Addendum to the Staff Assessment, Riverside County determined the appropriate fee for industrial projects is $5,620 per acre (Taussing and Associates 2003). The Board of Supervisors adopted the proposed fee structure as part of Ordinance No. 810.2 on July 22, 2003. Amendment 1 must comply with Ordinance 810 and 810.2 as part of Condition of Certification **BIO-12**.

SETTING

The site is located in western Riverside County which historically contained diverse habitats of value to wildlife, but now consists almost entirely of agricultural lands, annual grasslands, with interspersed areas of dense residential, urban, and exotic habitats. A few ephemeral washes are present, but most have been interrupted by railroad or road improvements. Furrows and road side ditches occasionally meet the criteria established in the Army Corps of Engineers Wetland Delineation Manual, and could be considered a wetland.

The Commission Decision described the project site as an agricultural field in wheat production. The project's linear facilities were mostly contained within agricultural lands and roads. A list of sensitive plant and wildlife species that could potentially occur on-site or in the vicinity of the linear facilities was created through the CNDDB Rarefind database, consultation with experts and agency personnel, and field reconnaissance. Reconnaissance-level surveys were conducted in May and June 2001 in preparation for the AFC, and again on October 5, 2004 and January 14, 2005 in preparation for the Amendment 1. No sensitive plants were identified during the field surveys and none are expected to occur. There were several focused wildlife surveys in 2001 including: southwestern willow flycatcher, least Bell's vireo, golden eagle, coastal California gnatcatcher, quino checkerspot butterfly, arroyo southwestern toad, western spadefoot toad, Stephens' kangaroo rat and San Bernardino kangaroo rat surveys. However, no sensitive wildlife species were sighted during field surveys, and they are not expected to use the site. The entire study area is potential foraging habitat for raptors. A small depression feature, known as MW-51, was identified during field work for the natural gas line corridor. The area may contain vernal pool fairy shrimp, a federally threatened species. While the species has never been positively identified as present, the applicant chose to presume its presence and staff agreed. Because no new sensitive species have been observed since the Commission Decision, and there have been no changes to the status of any of the species that were potentially present, the list of potential sensitive wildlife and plant species as found in the Staff Assessment and Commission Decision is still valid.

The new laydown area is located in an area classified as "Urban/Exotic/Residential" in the Staff Assessment. The 2004/2005 field reconnaissance surveys of the laydown area found that it remains in the same condition.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The suite of potential impacts to biological resources from the construction and operation of the proposed power plant can be categorized as follows:

1. Loss of potential Stephens' kangaroo rat habitat
2. Loss or contamination of potential fairy shrimp habitat
3. Loss of raptor foraging areas
4. Indirect impacts from nitrogen deposition on surrounding desert communities, including Joshua Tree National Park

The addition of a 11.5-acre laydown area increases temporary disturbance from 36.13 to 47.63 acres. The entire laydown area is within the Stephens' Kangaroo Rat Habitat Conservation Plan Fee Area. The project owner proposes to increase the amount paid in fees to match the new level of disturbance. Staff agrees this is the appropriate method to mitigate this impact. Staff recommends the modification of Condition of Certification **BIO-11**.

An ephemeral depression that was classified as potentially having vernal pool fairy shrimp habitat was identified north of the gas pipeline easement. The USFWS advised the project owner about what avoidance measures could be taken. Amendment 1 does not change the level of impact to this feature and the impact will remain less than significant so long as avoidance measures incorporated in Condition of Certification **BIO-10** are implemented.

The entire study area is potential foraging habitat for raptors, and the construction of the power plant was analyzed in the Commission Decision and found to be adverse, but not significant. The laydown area proposed in Amendment will reduce the amount of forage for these species slightly more, but this will only be a temporary impact. The temporary impact is only considered adverse considering the availability of a multitude of agricultural lands in the local area, and staff does not propose any additional mitigation.

The operation of the proposed facility will emit several air pollutants, including nitrogen dioxide and ammonia, into the atmosphere. These chemical components often react with the atmosphere to form fertilizing agents (e.g., HNO_3). Nitrogen deposition is the amount of nitrogen that converts to particulates and accumulates on soil or other surfaces. The nitrogen deposition rate considered sufficient to affect ecosystem structure and diversity is 3 to 10 kilograms nitrogen per hectare per year (kg-N/ha-yr) depending on vegetation type (Fox et al. 1989).

Staff identified in their FSA that power plant emissions, if unmitigated, would contribute to the degradation of air quality in the basin and possibly change the vegetation communities. The IEEC plant was required to implement BACT, which means that controls at the source will achieve the maximum reduction of nitrogen emissions technically feasible. In addition, emission reduction credits (ERCs) would be purchased through a market system at a ratio equal or greater than 1:1. (In Southern California credits for NOx emissions are traded under the RECLAIM program and the credits are called RECLAIM Trading Credits or RTCs.) The ratio is in part determined by whether the credits are purchased locally (smaller ratio) or regionally (higher ratio) (see the AIR QUALITY section of the FSA). Both BACT and RTCs were to be used to mitigate NOx emissions for the IEEC plant (Conditions of Certification **Air-SC9**.)

Amendment 1 changes the type of turbines used, and subsequently the air quality impacts that will result for the project have been revised. The amount of nitrogen in the form of NOx that will be emitted by the project's turbines has increased from 169.4 tons per year to 214.6 tons per year. However, the project needs less RTCs than the previous project to offset nitrogen-based emissions owing to changes in operation (see AIR QUALITY section of this Amendment). Staff supports any effort to ensure the entire offset needed (322,967 lbs/year) be from a NOx source to mitigate potentially adverse biological resource impacts.

An analysis of nitrogen deposition impacts to Joshua Tree National Monument was completed as part of the Commission Review (IEEC 2002). A new analysis of the potential impacts to the nearby wilderness and national parks was completed as part of Amendment 1 (IEEC 2005, Section 3.1.2.3). No significant changes were found between the approved project, and the one under consideration in this Amendment 1, and no additional mitigation is requested by staff.

CONCLUSIONS

The only identified impact from the proposed project was an increase of disturbance within potential Stephens' kangaroo rat habitat. Staff has recommended a change to Condition of Certification **BIO-11** that will reduce the impact to less than significant levels. The project is in compliance with all LORS after adoption of the modified condition.

CONDITIONS OF CERTIFICATION

Adoption of all the Conditions of Certification as found in the Commission Decision, and the modification of Condition of Certification **BIO-11** are required to ensure continued compliance with LORS, and/or to ensure that impacts of Inland Empire Energy Center will not have any significant impact on the environment. Staff recommends the following modification to Condition of Certification **BIO-11**.

Deleted text is shown in ~~strikethrough~~, added text is in **bold** and **double underlined**.

BIO-11 Prior to site or related facilities mobilization, the IEEC shall comply with the provisions of Riverside County Ordinance No. 663, which requires the payment of fees for permanent and temporary loss of historical Stephens' kangaroo rat habitat within the Stephens' kangaroo rat HCP fee assessment area. The applicant shall purchase habitat credits for temporary impacts to ~~36.13~~ **47.63** acres and permanent impacts to 38.60 acres. Fees shall be based on the most current fees assessed by Riverside County. Monies will be paid directly to the Riverside County Habitat Conservation Agency.

Verification: At least 30 days prior to site or related facilities mobilization, the project owner shall demonstrate to the CPM evidence of receipt of payment of the Stephens' kangaroo rat habitat fee by the County of Riverside. At least 30 days prior to site mobilization (or other CPM-approved timeframe), the project owner shall submit to the CPM a written certificate or letter from the County of Riverside stating the date and amount of funds received.

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CULTURAL RESOURCES ANALYSIS

DOROTHY TORRES

REQUEST

IEEC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site.

BACKGROUND

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to cultural resources were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified.

ANALYSIS

Energy Commission cultural resources staff reviewed the petition and assessed the impacts of this proposal on Cultural Resources. It is the cultural resources staff's opinion that revisions to Cultural Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769). All cultural resources conditions of certification will also be applicable to the amendment.

FACILITY DESIGN ANALYSIS

KEVIN ROBINSON, AL MCCUEN AND STEVE BAKER

REQUEST

Inland Empire Energy Center, LLC requests to amend the Inland Empire Energy Center project (IEEC) to:

- Substitute two General Electric (GE) Frame 7H gas turbine/steam turbine generator trains for the two GE Frame 7F gas turbine generators and one steam turbine generator that were initially certified; and
- Add two additional temporary laydown and construction worker parking areas to the project site.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical and electrical) are described in the original IEEC Commission Decision.

ANALYSIS

The request to substitute two General Electric (GE) Frame 7H gas turbine/steam turbine generator trains for the two GE Frame 7F gas turbine generators and one steam turbine generator that were initially certified does not impact the subject area of Facility Design.

The request for additional laydown and parking areas does not impact the subject of Facility Design.

MITIGATION MEASURES AND CONDITIONS

Energy Commission staff believes that the Facility Design conditions of certification included in the original IEEC certification are applicable to the amendment.

CONCLUSIONS

The requested change, from GE Frame 7F machines to GE Frame 7H machines, will have no effect on Facility Design. From this standpoint, staff recommends that the Petition be granted. This recommendation is based on the conclusion that the proposed modification retains the intent of the original Commission Decision and Facility Design Conditions of Certification.

POWER PLANT EFFICIENCY ANALYSIS

STEVE BAKER

REQUEST

Inland Empire Energy Center, LLC petitions to amend the Inland Empire Energy Center project (IEEC) to:

- Substitute two General Electric (GE) Frame 7H gas turbine/steam turbine generator trains for the two GE Frame 7F gas turbine generators and one steam turbine generator that were initially certified; and
- Add two additional temporary laydown and construction worker parking areas to the project site.

BACKGROUND

The IEEC was certified by the Energy Commission on December 17, 2003. The project incorporated the most modern, fuel efficient gas-fired generating technology then commercially available, the GE Frame 7F gas turbine generator in a combined cycle configuration.[1]

In recent years, GE has pursued development of the H-technology gas turbine. The first H machine, a 50 Hz Frame 9H unit rated at 480 MW, was installed at Baglan Bay, Wales, and began operational testing in November, 2002.[2] The first 60 Hz Frame 7H machine was ordered by Sithe Energies for installation at the Heritage Power Station in Scriba, NY, but the order was subsequently cancelled due to unfavorable economic conditions.[3]

GE proposes to install, operate and test this initial Frame 7H machine. In order to pursue this essential step in the development and marketing of this new product, GE has completed an agreement with Calpine to install the first Frame 7H machine, along with a second machine, at the IEEC. Substituting these two larger capacity machines for the Frame 7F machines initially certified necessitates this amendment.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

There are no LORS that apply to the efficiency of a power plant such as the IEEC.

[1] A combined cycle power plant generates electricity with one or more gas turbine generators, and one or more steam turbine generators that are driven (partly or wholly) by gas turbine exhaust heat.

[2] Gas Turbine World, Summer 2003, p. 26.

[3] Power Engineering, July 2002, p. 22.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

CEQA requires that a project be analyzed to determine whether "…feasible measures [exist] which could minimize significant adverse impacts, including where relevant, inefficient and unnecessary consumption of energy" (Cal. Code Regs., tit. 14, § 15126.4[a][1]). Energy Commission staff performed this analysis, which is described in the IEEC Staff Assessment dated May 2003, and concluded that the IEEC would consume energy in the most efficient manner practicable. Thus, the project would create no significant adverse energy impacts. This analysis is revisited here in light of the proposal to substitute Frame 7H gas turbines for the Frame 7F machines initially certified.

ANALYSIS

FUEL EFFICIENCY

The IEEC, as certified with Frame 7F machines, is predicted to generate 538 MW at baseload (with no duct firing) at an efficiency of approximately 56.5 percent lower heating value (LHV). With maximum duct firing, the plant would generate up to 704 MW at 53.2 percent LHV (Staff Assessment, pp. 6.3-4 to 6.3-5; p. 6.3-8).

The Frame 7H machines are currently available solely as one-on-one combined cycle units, in which the gas turbine, steam turbine and single generator share a common shaft. Duct firing is not an option at this time; therefore, the plant is rated only at baseload. The IEEC, as amended, would generate 790 MW net at an efficiency of approximately 59.8 percent LHV (Petition for Amendment, p. 2-9). This represents an increase in maximum generating capacity of 86 MW and an increase in fuel efficiency ranging from 5.8 percent (compared to the certified project at baseload) to 12.4 percent (compared to the certified project at maximum output).

The increase in fuel efficiency expected from the amended Frame 7H project represents a substantial improvement over the certified project. Energy Commission staff considers this a beneficial impact on energy supplies.

FUEL CONSUMPTION

The IEEC, as certified, is predicted to consume natural gas fuel at a rate of 77.9 billion Btu/day LHV at baseload, and 103.6 billion Btu/day at peak output.

Energy Commission staff predicts the amended project will consume natural gas fuel, at its baseload rating, at a rate of approximately 108.2 billion Btu/day LHV. While this represents an increase over the certified project, it is a small increase. Staff believes this increase in maximum fuel consumption will create no adverse impacts on fuel supplies beyond those analyzed for the project as originally certified.

ADDITIONAL LAYDOWN AND PARKING

The request for additional laydown and parking areas does not impact the subject of Power Plant Efficiency.

MITIGATION MEASURES AND CONDITIONS

The original project certification included no Efficiency Conditions of Certification. Energy Commission staff believes no such conditions are warranted by the amendment, and proposes none.

CONCLUSIONS

The requested change, from GE Frame 7F machines to GE Frame 7H machines, will result in significantly improved fuel efficiency. From the standpoint of Power Plant Efficiency, staff recommends that the Petition be granted. This recommendation is based on the following:

1. I have analyzed the situation from the standpoint of Power Plant Efficiency and conclude there will be no new or additional significant environmental impacts associated with this action.
2. I conclude that the amendment is based on new information that was not available during the licensing proceedings.
3. I conclude that the proposed modification retains the intent of the original Commission Decision.

GEOLOGY, MINERAL RESOURCES AND PALEONTOLOGY ANALYSIS

DAL HUNTER, PH.D., C.E.G.

REQUEST

IEEC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site.

BACKGROUND

The 670-megawatt project was certified by the energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Geology, Mineral Resources and Paleontology were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified.

ANALYSIS

Energy Commission Geology, Mineral Resources and Paleontology staff reviewed the petition and assessed the impacts of this proposal on Geology, Mineral Resources and Paleontology. It is the Geology, Mineral Resources and Paleontology staff's opinion that revisions to Geology, Mineral Resources and Paleontology Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

HAZARDOUS MATERIALS ANALYSIS

ALVIN GREENBERG, PH.D.

SUMMARY OF CONCLUSIONS

The Inland Empire Energy Center (IEEC), LLC, has petitioned to amend the certification for IEEC to include a revised power generation configuration and two new construction laydown areas. Staff has reviewed the amendment and concluded that the design changes proposed are fully mitigated with implementation of the existing conditions of certification, and with the additional Condition of Certification (**HAZ-13**) proposed by staff to address safety at the natural gas compressor building. With staff's proposed mitigation measures, the project will comply with all applicable LORS and will pose little potential for significant impacts on the public from the use and handling of hazardous materials.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The only new LORS associated with this amendment not considered in staff's original analysis of the Inland Empire Energy Center concerns the natural gas compressor building.

Typically, structures such as compressor enclosures on a power plant site are subject to the requirements set forth in the California Building Code (CBC). However, in cases where a compressor is in a gas line that does not terminate at a single end-user, it is covered by federal requirements. In remote locations where there is little or no concern regarding potential public exposure, it may not be necessary to specifically require special mitigation. However, the CBC could still apply and there is significant disagreement regarding proper classification pursuant this code. Staff has thoroughly evaluated the efficacy of applying the fire protection requirements in the CBC to compressor enclosures and has concluded that the CBC's requirements were:

- not intended to address these structures,
- do a poor job of reducing risk when risk reduction is necessary, and
- impose unnecessary and ineffective requirements when risk reduction is not necessary.

Staff therefore follows standards developed by the National Fire Protection Association. *NFPA 850, Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations*, which addresses enclosures for fuel gas line compressors, normally unoccupied, and states that these structures should be classified as "special purpose industrial occupancies", and thus should be designed and built in accordance with the recommendations of the following model codes:

- NFPA 850 – Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations,

- NFPA 101 – Life Safety Code,
- NFPA 54 – National Fuel Gas Code,
- NFPA 58 – Liquefied Petroleum Gas Code,
- ANSI B31.1 – Code for Power Piping,
- ANSI B31.3 – Code for Process Piping,
- Title 49, Code of Federal Regulations (49 CFR), Part 192

Such treatment for gas compressor enclosures is consistent with that given in these codes for the design of power plant boiler and turbine enclosures, structures housing similar equipment and serving essentially equivalent purposes.

SETTING

The IEEC proposes to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators (CTGs) and one steam turbine generator (STG) to a new configuration using two GE 107H Systems, and to add two additional temporary areas near the project site for construction worker parking and secondary laydown. The IEEC was approved to be located on approximately 45.8 acres located near the community of Romoland in unincorporated Riverside County. The proposed changes to the power generation configuration will require revisions to the site arrangement, including the location of structures, spacing, and moving the entire facility approximately 80 feet south. The proposed facility will still occupy approximately 35 acres of the 45.8-acre site, with the fenced area increased from 24 to about 28 acres (IEEC Amendment Section 2.1.1).

The closest residential area lies approximately 600 feet north of the originally proposed northern site boundary. Some isolated homes exist to the south and southwest of the facility fenceline. The closest of these homes lie approximately 515 feet from the southwest corner of the originally proposed site. The closest sensitive receptors (Romoland Elementary School and Romoland Headstart) are located approximately 1,100 feet north-northwest of the originally proposed northern fenceline (Calpine 2002a, Table 53-2). The relocation of the facility 80 feet south would bring its southwest corner approximately 80 feet closer to the nearest residences, and its northern boundary approximately 80 feet further from Romoland Elementary School and Romoland Headstart. An updated list of sensitive receptors within 6 miles of the project site is provided as Table 3.8-1 of the IEEC Amendment.

Changes to the site arrangement that involve the use and handling of hazardous materials include the following:

- the relocation of the aqueous ammonia storage tanks from near the northern boundary (in the center of the IEEC site) to north of the western cooling tower (southwest of the original location),
- the relocation of the hydrogen tube storage trailer to the space between the generator step-up transformers,
- the addition of gas compressors and an enclosing building and the relocation of the natural gas metering station, and
- the use of one new chemical, HFC R-123, as the refrigerant in the inlet chiller.

ANALYSIS

RELOCATION OF AMMONIA TANKS

Reconfiguration of the site layout to accommodate new equipment will require the aqueous ammonia tanks to be relocated to north of the western cooling tower; however, the quantity stored on-site (a maximum of 16,000 gallons of 28% aqueous ammonia in each tank) and the design of the ammonia storage facility will remain unchanged. Staff has reviewed the new proposed location for the ammonia tanks, and its proximity to residences and sensitive populations in order to evaluate any added risks associated with the new location.

The Off-site Consequence Analysis (OCA) prepared by the applicant for the original proceedings showed that off-site airborne concentrations of ammonia would not exceed the level the CEC uses to establish insignificance (75 ppm) at any off-site location. For the worst-case scenario (failure of the storage tank with complete loss of contents), a concentration of less than 1 ppm was predicted to occur at the original fenceline, a distance of about 100 feet from the aqueous ammonia storage tank. For the alternative scenario (a spill during transfer of ammonia from the delivery vehicle to the storage tank), a concentration of 26 ppm was predicted to occur at the original fenceline, a distance of about 140 feet from the loading area (FWEC 2002d, Table 53-3). This modeling also estimated that the airborne concentration of ammonia at the Romoland School would be less than 1 ppm, a level that presents no hazard to even sensitive asthmatic children and which would not be detectable by the sense of smell.

Staff reviewed the applicant's modeling calculations during the original proceedings, conducted independent modeling using the EPA-approved SLAB model, confirmed the accuracy of the applicant's modeling, and found that the distance to the CEC Level of Concern (75 ppm) would be 23-27 meters (75 - 88 feet) from the storage tanks (worst case scenario). Staff also found that 75 ppm would not be reached except in the spill area for an accidental release during transfer (the alternative scenario). Staff's results also confirmed that the modeled airborne concentration of ammonia at the Romoland School would be less than 1 ppm.

Since ammonia concentrations higher than CEC's level of concern would be confined to the area immediately surrounding the ammonia tanks, and since there are no sensitive receptors or residences near the area potentially affected by an accidental release, staff finds that due to the engineering controls originally proposed to be implemented by the applicant for the storage and transfer of aqueous ammonia, no significant risk would be posed to the public as a result of the relocation of the aqueous ammonia tanks.

RELOCATION OF HYDROGEN TRAILER

The hydrogen tube trailer is proposed to be relocated to the space between the generator step-up transformers. Staff's original Condition of Certification (**HAZ-9**) ensures that hydrogen gas storage cylinders are stored in an area out of the plane of the turbines and that no combustible or flammable material is stored within 50 feet of the hydrogen cylinders. Staff therefore concludes that with the implementation of the existing conditions of certification, the relocation of the hydrogen tube trailer poses no significant risk.

GAS COMPRESSORS AND GAS METERING STATION

Changes to the IEEC configuration include the addition of on-site natural gas compressors with fin-fan coolers, proposed to be located north of the east cooling tower, and a natural gas metering station to be relocated to the south side of the east cooling tower (IEEC Amendment Section 2.1.1). A building will house the gas compressors in order to provide noise abatement and protection from weather for the equipment and for maintenance activities. The compressors are needed to boost the natural gas pressure in order to meet the inlet fuel pressure requirements of the combustion turbines.

When an enclosure is provided for gas compressors, questions about safety can arise. Gas compressor enclosure design should address the potential magnitude, duration, and safe setback distances for potential accidental releases and their potential impacts on the public. Accidental releases of natural gas from pipelines and compressor buildings have resulted in explosions and fires. Therefore, besides meeting the requirements of all applicable building and safety codes as described in the LORS section above, safety concerns dictate that additional measures be implemented if there are schools, hospitals, retirement facilities, residences, or public gathering places within 1500 feet of the compressor building. This distance is consistent with impact distances reported for some high pressure gas releases, such as the recent accidental release and explosion that occurred at Ath, Belgium on July 30, 2004. The additional safety measures include, but are not limited to, adequate maintenance being performed on the compressors, the installation of both automatic and manual shut-off valves, fire and gas detection sensors placed inside the gas compressor building, the proper location of fire suppression equipment, and ensuring unobstructed access to the compressor building by off-site fire department equipment and personnel. Also, to reduce the likelihood of such events, the CEC will evaluate the maintenance schedule proposed for the gas compressors. The maintenance schedule should be consistent with the requirements set forth in 49 CFR Part 192 as part of the federal pipeline integrity management rules. Therefore, to ensure adequate protection of the public, staff is proposing Condition of Certification **HAZ-13**.

HYDROFLUOROCARBON (HFC) R-123

The types and quantities of hazardous chemicals used and stored on site will not change from those approved for the original IEEC (presented as Appendix C of the Commission Decision), except for the addition of one chemical, HFC R-123 for use as the refrigerant in the inlet chiller. This refrigerant will be sealed inside the chiller equipment, which consists of four chillers, with a total maximum quantity on-site of 18,000 lbs. The chiller system will be located between the two HRSGs, and will replace the originally proposed fogging system by providing chilled water to cool the combustion turbines' inlet air. The chemical name for R-123 is 2,2-dichloro-1,1,1-trifluoroethane (CAS # 306-83-2), and it has no CERCLA-SARA or CalARP reportable/threshold quantities, and it is not listed under Proposition 65. R-123 is a mild eye irritant, and if inhaled in high concentrations it can be toxic (IEEC Amendment Section 3.5). Staff finds that the use of R-123 does not pose any added risk to the public than those previously analyzed.

CONCLUSIONS

Staff has reviewed the changes proposed to the IEEC and concluded that the design changes proposed are fully mitigated with implementation of the existing conditions of certification, and with the additional Condition of Certification (**HAZ-13**) proposed by staff to address safety of the natural gas compressor building. With staff's proposed mitigation measures, the project will comply with all applicable LORS and will pose no significant impacts on the public from the use, transportation, storage, and handling of hazardous materials.

REVISIONS TO EXISTING CONDTIONS AND PROPOSED CONDITIONS OF CERTIFICATION

Added text is in bold and double **underlined**.

HAZ-13 The project owner shall include the following safety measures for the natural gas compressor enclosure:

1. **inside natural gas sensors**
2. **inside fire (flame) detectors**
3. **automatic gas compressor emergency shut-off valves actuated by the inside gas sensors**
4. **outside manual shut-off valves located at least 50 feet from the gas compressor building**
5. **fire suppression equipment located outside and adjacent to the compressor building**
6. **unobstructed access to the compressor building by off-site fire department equipment and personnel from two directions**
7. **a maintenance schedule for the gas compressors**

Verification: At least thirty (30) days prior to the introduction of natural gas to the pipeline, the project owner shall provide the CPM with a written description of the safety measures applied to the gas compressor enclosure.

REFERENCES

CALPINE (Calpine Corporation/Hatfield). 2002a. Response to data requests made by CEC staff at a workshop for the Inland Empire Energy Center Project on February 26, 2002. Submitted to the California Energy Commission, April 15, 2002.

FWEC (Foster Wheeler Environmental Corp/Booth). 2002d. Workshop Responses to CEC Staff Workshop Data Requests February 26, 2002. Submitted to the California Energy Commission, April 16, 2002.

Inland Empire Energy Center (IEEC) Amendment No. 1: GEH Technology and additional laydown areas. Volumes I and II. March 2005.

National Fire Protection Association, 2005. NFPA 850: Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations.

LAND USE ANALYSIS

AMANDA STENNICK

REQUEST

IEEC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site.

BACKGROUND

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Land Use were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project and no new LORS have been identified.

ANALYSIS

Energy Commission Land Use staff reviewed the petition (and 5/17/05 addendum) and assessed the impacts of this proposal on Land Use. The amended project includes the addition of three parcels for the temporary use of construction laydown and parking areas. These parcels were not part of the Inland Empire Energy Center project that was certified in 2003 and as such, require analysis to determine LORS compliance. The parcels are described below.

1. Assessor Parcel Number 351-150-039 4.86 acres.
2. Assessor Parcel Number 351-150-040 4.77 acres.
3. Assessor Parcel Number 331-180-007 1.97 acres.

The first two parcels are located in Planning Area 2 of the Meniffee North Specific Plan. Planning Area 2 is zoned M-H (Industrial) pursuant to Riverside County's Zoning Ordinance 348 and is designated Industrial Park pursuant to the Riverside County General Plan. The last parcel is located in Planning Area 3 of the Meniffee North Specific Plan. Planning Area 3 is zoned M-H (Industrial) pursuant to Riverside County's Zoning Ordinance 348 and is designated Industrial Park pursuant to the Riverside County General Plan.

Land Use staff is satisfied that all applicable parking requirements as specified in Section 18.12 of Riverside County's Zoning Ordinance 348 for the amendment and addendum have been met through the Conditions of Certification in the Traffic and Transportation section of this document.

It is the Land Use staff's opinion that the amended project is consistent with the current development pattern for the area established by the Riverside County General Plan and the Meniffee North Specific Plan; revisions to Land Use Conditions of Certification are not required and the project as modified will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

NOISE AND VIBRATION ANALYSIS

SHAHAB KHOSHMASHRAB

REQUEST

Inland Empire Energy Center, LLC requests to amend the Inland Empire Energy Center project (IEEC) to:

- Substitute two General Electric (GE) Frame 7H gas turbine/steam turbine generator trains for the two GE Frame 7F gas turbine generators and one steam turbine generator that were initially certified; and
- Add two additional temporary laydown and construction worker parking areas to the project site.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

LORS for Noise apply to the construction and operation of the project. These LORS were identified in the Staff Assessment (CEC 2003), in which the Energy Commission staff (staff) concluded that the project would comply with these LORS. Below, staff has reexamined the original analysis in light of the proposals to substitute Frame 7H gas turbines for the Frame 7F machines and to add the construction laydown area.

THE CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

CEQA requires that significant environmental impacts be identified, and that such impacts be eliminated or mitigated to the extent feasible. Staff performed this analysis for noise produced by the IEEC project, which is described in the Staff Assessment, and concluded that the project would not create significant environmental noise impacts on the sensitive noise receptors. This analysis is reexamined here to reflect the above proposals.

ANALYSIS

Staff analyzes the project to determine whether it will likely be built in accordance with the applicable noise LORS and consistent with the CEQA guidelines. The ambient noise levels in the vicinity of the project have not changed since the project was certified, and there are no new sensitive noise receptors in the area that are located closer to the project site than the existing project design points analyzed in the original proceedings. The turbine reconfiguration will involve an additional steam turbine and different noise generation profile for the combustion turbine equipment and some other equipment than was previously considered. For this reason, this amendment includes a noise modeling analysis of the reconfigured power plant.

The results of this modeling show the expected project noise level during full load operation at the nearest sensitive receptors to be 45 dBA L_{eq} (IEEC 2005, § 3.7.2). This is consistent with the requirement of Condition of Certification **NOISE-6** (CEC 2003a) and does not violate the applicable noise LORS.

These results also show the combined (project plus ambient) noise levels to be between zero and 1 dBA above the existing ambient levels at these receptors (IEEC 2005, § 3.7.2). An increase of 1 dBA is unnoticeable and the project, thus, remains consistent with the CEQA guidelines.

Construction noise levels are not expected to increase. The use of the additional laydown area will be temporary (during the project construction) and will not create significant adverse noise impacts on the sensitive noise receptors.

MITIGATION MEASURES AND CONDITIONS

The noise conditions of certification embodied in the Energy Commission Decision apply to this amendment. The project owner proposes, in this amendment, to add high pressure air blow to Noise Condition of Certification **NOISE-4** as an available option. This option is not expected to create noise levels higher than those generated by the high pressure steam blow and will not create any additional noise impacts on the noise sensitive receptors. Thus, staff recommends that this request be granted and proposes the following revisions to this condition (changes in **bold** and double **underline** text):

NOISE-4 If a traditional, high-pressure steam **or air** blow process is employed, the project owner shall equip steam/**air** blow piping with a temporary silencer that quiets the noise of steam/**air** blows to no greater than 86 dBA measured at a distance of 100 feet. The noise level at the nearest residence produced by this operation must be less than a constant value of 48 dBA. The project owner shall conduct high pressure steam/**air** blows only during the hours of 8 a.m. to 5 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance.

If a low-pressure continuous steam blow or air blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected period of execution, to the CPM, who shall review the proposal with the objective of ensuring that the resulting noise levels from this process do not exceed 42 dBA hourly Leq at the most-affected residence. If the low-pressure process is approved by the CPM, the project owner shall implement it in accordance with the requirements of the CPM.

Verification: At least 15 days prior to the first high-pressure steam/air blow, the project owner shall submit to the CPM drawings or other information describing the temporary steam/**air** blow silencer and the noise levels expected, and a description of the steam/**air** blow schedule.

At least 15 days prior to any low-pressure continuous steam/**air** blow, the project owner shall submit to the CPM drawings or other information describing the process, including the noise levels expected and the projected time schedule for execution of the process.

All other noise conditions apply without change. No further mitigation is required.

CONCLUSIONS

From the standpoint of Noise and Vibration, staff recommends that this Petition be approved. This recommendation is based on the following conclusions:

1. There will be no new or additional significant environmental impacts associated with this action. The operation and construction noise levels will remain in compliance with the applicable noise LORS and will not result in significant increase in the ambient noise levels.
2. The proposed modification retains the intent of the original Energy Commission Decision and conditions of certification.
3. The amendment is based on new information that was not available during the licensing proceedings.

REFERENCES

CEC (California Energy Commission). 2003. Final Staff Assessment (pp. 5.6-1 through 5.6-25), Inland Empire Energy Center (01-AFC-17), May 23, 2003.

CEC (California Energy Commission). 2003a. Energy Commission Decision (pp. 300-318), Inland Empire Energy Center (01-AFC-17), December 17, 2003.

IEEC (Inland Empire Energy Center). 2005. Amendment No.1, Amendment to the Certification for the Inland Empire Energy Center (01-AFC-17), Docketed on March 11, 2005.

PUBLIC HEALTH ANALYSIS

ALVIN GREENBERG, PH.D.

SUMMARY OF CONCLUSIONS

The Inland Empire Energy Center LLC (IEEC), has petitioned to amend the certification for IEEC to include a revised power generation configuration and a new construction laydown area. Staff has analyzed potential public health risks associated with construction and operation of the amended IEEC project and does not expect any significant adverse cancer, or short- or long-term noncancer health effects from project emissions.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

There are no new LORS associated with this amendment not considered in staff's original analysis of the Inland Empire Energy Center Project.

SETTING

IEEC proposes to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators and one steam turbine generator to a new configuration using two GE S107H Systems, and to add two additional temporary areas near the project site for construction worker parking and secondary laydown. The IEEC was approved to be located on approximately 45.8 acres located near the community of Romoland in unincorporated Riverside County. The entire project is proposed to be relocated approximately 80 feet south of the original site, but the proposed facility will still occupy approximately 35 acres of the 45.8-acre site, with the fenced area increased from 24 to about 28 acres (IEEC Amendment Section 2.1.1).

The closest residential area lies approximately 600 feet north of the originally proposed northern site boundary. Some isolated homes exist to the south and southwest of the facility fenceline. The closest of these homes lie approximately 515 feet from the southwest corner of the originally proposed site. The closest sensitive receptors (Romoland Elementary School and Romoland Headstart) are located approximately 1100 feet north-northwest of the originally proposed northern fenceline (Calpine 2002a, Table 53-2). The relocation of the facility 80 feet south would bring its southwest corner approximately 80 feet closer to the nearest residences, and its northern boundary approximately 80 feet further from Romoland Elementary School and Romoland Headstart. An updated list of sensitive receptors within 6 miles of the project site is provided as Table 3.8-1 of the IEEC Amendment Petition.

The design changes proposed to the IEEC energy generation configuration would result in changes to stack emissions. In addition, two 8-cell cooling towers will replace the single 14-cell tower originally proposed, the single 1,000 kW natural gas-fired generator would be replaced with two 2,000 kW diesel-fired standby generators, and the diesel fire pump will be decreased in size from the original 370 hp to 300 hp (IEEC Amendment Section 2.1.2). The new design also includes increases to the auxiliary boiler stack height (now 100 feet), the standby generator engines' stack height (from 10 to 75 feet), and to the emergency fire pump engine stack height (from 10 to 15 feet) (IEEC Amendment Section 3.1.2.2).The project owner has prepared a revised Health Risk Assessment (HRA) that models the cancer risk, and acute and chronic hazard indices resulting from noncriteria pollutants potentially emitted from the new equipment.

ANALYSIS

SITE CONTAMINATION

Potential risks to public health may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation. A Phase I Environmental Site Assessment (ESA) has been performed by Foster Wheeler Environmental Corporation as part of the original proceedings (Calpine 2001a, Appendix H). The ESA showed no evidence of significant site contamination. Since the new proposed location for the IEEC facility is entirely within the original 45.8 acre parcel, staff finds that the Phase I ESA conducted by Foster and Wheeler includes the new site and therefore no significant contamination is expected to be encountered during site preparation. Staff believes that if unanticipated environmental site issues arise during site preparation and/or construction, existing Conditions of Certification (COCs) **WASTE-1** and **2** will ensure that these issues are handled appropriately to protect public health.

CONSTRUCTION EQUIPMENT

The operation of construction equipment will result in air emissions from diesel-fueled engines. Exposure to diesel exhaust causes both short- and long-term adverse health effects. Short-term effects can include increased cough, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Long-term effects can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies also strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer.

Site preparation and construction of the amended project is expected to take place over a period of 36 months, in contrast to the 25 months estimated for the original IEEC. In addition, the average on-site workforce estimated for the amended project is 366 people, while an average workforce of 250 was estimated for the original IEEC (Calpine 2001a Section 3.7 and IEEC Amendment Section 2.4). In order to mitigate potential impacts from particulate emissions during the operation of diesel-powered construction equipment, in the original proceedings the Energy Commission approved Air Quality Conditions of Certification that require the use of ultra-low sulfur diesel fuel and the installation of soot filters on diesel equipment. The catalyzed diesel particulate filters are passive, self-regenerating filters that reduce particulate matter, carbon monoxide, and hydrocarbon emissions through catalytic oxidation and filtration. The degree of particulate matter reduction is comparable for both mitigation measures in the range of approximately 85 to 92 percent. Such filters will reduce diesel emissions during construction and reduce any potential for significant health impacts.

Mitigation measures originally proposed by the project owner to reduce PM10 concentrations during construction include the use of extensive fugitive dust control measures (stipulated by SCAQMD Rule 403). The fugitive dust control measures are assumed to result in 90 percent reductions of emissions. Staff therefore finds that implementation of the measures described above will reduce risks due to diesel emissions during construction of the IEEC to an insignificant level.

HEALTH RISK ASSESSMENT

Project owner's Approach

The toxic air contaminant emissions associated with the new gas turbines are slightly higher than those estimated in the previous analysis. The toxic air contaminant emissions associated with the auxiliary boiler and cooling towers are also slightly higher than in the previous analysis. The main reasons for increased emissions are the higher heat input levels for the new equipment, more conservative operating assumptions, revised emission factors for some of the contaminants, and an increased recirculation rate for the cooling towers. IEEC Amendment Tables 3.8-2 and 3.8-3 show maximum hourly and annual emissions for the gas turbines and auxiliary boiler. The maximum fuel use is combined with the emission factor for each toxic air contaminant to estimate hourly and maximum annual emissions. Emission factors are estimates of the amounts of toxic substances released per unit of fuel burned and are from data compiled by the Ventura County Air Pollution Control District and the California Air Toxic Emission Factors (CATEF II) database maintained by the California Air Resources Board.

IEEC Amendment Table 3.8-4 shows maximum hourly and annual emissions for the cooling towers. The toxic contaminant emissions for the cooling towers were calculated based on the maximum metal concentrations expected in the cooling water and the maximum expected cooling tower drift rate. Recycled water for cooling will be delivered by the Eastern Municipal Water District (EMWD) as in the original proposal, but due to recent changes in EMWD's recycled water system, the IEEC will receive recycled water primarily from Perris Valley Regional Water Reclamation Facility (RWRF). Raw water will be provided by the Metropolitan Water District (MWD) through the EMWD, as in the previous arrangement (IEEC Amendment Section 2.1.5). Water treatment will remain the same as in the previous arrangement, with the exception of electro-deionization (EDI) units added onsite and an ultraviolet disinfection process added downstream of the EDI (IEEC Amendment Section 2.1.7).

IEEC Amendment Table 3.8-5 shows the maximum hourly and annual diesel emissions for standby/emergency engines. Diesel particulate emissions from the emergency diesel fire pump are slightly decreased due to the smaller engine size currently proposed. At the same time, two new diesel-fired backup generators are added (replacing one natural-gas fired backup engine), and the size of the standby generator engines has increased, contributing to a total increase in diesel emissions from stand-by generators.

The new screening level health risk assessment was prepared by the project owner using the California Air Resources Board (CARB)/ Office of Environmental Health and Hazard Assessment (OEHHA) Hotspots Analysis and Reporting Program (HARP) computer program. Table 3.8-6 of the IEEC Amendment summarizes the results of the HRA. The calculated maximum cancer risk and acute hazard index are slightly higher than in the previous analysis, while the chronic hazard index is slightly lower. Figures HRA-1 and HRA-2 of the IEEC Amendment show the distribution of cancer risk to residences and workers respectively. According to the project owner, the main reason for the increased risk is the use of a different computer model, although increases in toxic air contaminant emission rates also contributed (IEEC Amendment Section 3.8.2.3).

In summary, the IEEC Amendment Petition states that the following emission changes will occur:

- Toxic air contaminant (TAC) emissions from the gas turbines will be higher than levels in the original Application for Certification (AFC).
- TAC emissions for the auxiliary boiler will be higher in the proposed design.
- TAC emissions for the cooling towers will be higher in the proposed design.
- Diesel particulate emissions from the emergency fire pump engine will be lower in the proposed design.
- The standby generator engines were changed from natural gas-fired to diesel-fired so there will be an increase in diesel particulate emissions for these engines.

The IEEC Amendment request states that the HARP model was used to assess cancer risk and chronic and acute impacts. While HARP was indeed used in the risk assessment portion of the analysis, it was not used for the air dispersion modeling of facility emissions. Instead, the Industrial Source Complex (ISC) model was used separately to generate ground level concentrations and then these values were input to the HARP model to determine risks and hazards. While this approach is valid, it complicates the review and evaluation of the risk assessment in that the parameters used to build the ISC model were not readily apparent to staff. Additionally, the manner in which risk was calculated was confusing and lacked transparency. The risk assessment used a weighted risk "rate" for each source in place of emission rates in the ISC modeling analysis. The ISC model output then gave total cancer risk at each receptor. It was not readily apparent how this was accomplished, however, and thus this precluded validation of the results using standard HARP procedures.

The IEEC Amendment indicates that the greatest contribution to cancer risk and acute and chronic hazards are emissions from the gas turbines. Also, cancer risk and acute hazard are higher in the amendment compared to the original AFC while chronic hazard is lower. In the amendment, cancer risk is still below staff's and the SCAQMD significance level of 10 in one million and acute and chronic hazards are below the respective agencies' significance index level of 1.0. The project owner acknowledges that there were increases in TAC emission rates from the combustion equipment but states that "the main reason for the change in risk impacts is due to the use of a different computer model to characterize the risks associated with these pollutants." This is apparently in reference to the use of the HARP model in the amendment as opposed to the use of the CARB/OEHHA HRA program in the August 2001 AFC. Staff cannot confirm the above statement regarding the change in risk impacts in the absence of a side-by-side comparison of risks determined for the new project design by the HRA and HARP programs.

Staff also found that certain information in the project owner's health risk assessment was lacking or unclear. These items include:

- The location of the point of maximum impact.
- Sensitive receptor locations.
- Assessment of non-inhalation pathways.
- Speciation of polycyclic aromatic hydrocarbons (PAHs) emitted (the project owner presented one emission factor for total PAHs).

Staff's Approach

The HARP model (without changes) was used in staff's evaluation of the risk assessment. Based on information obtained from the amendment, appendices and ISC model files, the following information was input to the HARP model:

1. Stack parameters.
2. Annual and maximum hourly toxic air contaminant emissions.
3. Approximate center of property estimated at UTM coordinates UTM-E 484350, UTM-N 3732962.
4. Gas turbine emissions based on 8760 hours of operation per year at a cold ambient temperature baseline operating mode which represents a more conservative assumption than used in the original AFC (8760 hours of operation per year at an annual average ambient temperature baseline).
5. 1981 meteorological data from Riverside provided on CD by Sierra Research ("Inland Empire Energy Center Air Quality Modeling Files, February 15, 2005").
6. Property boundaries estimated by reviewing the maps included in the amendment and appendices.
7. Building geometry obtained from the BPIP file "IEEC_07c.OUT" (building-wake downwash file) provided on CD by Sierra Research. Thirty-two on-site buildings were included in the air dispersion modeling by entering their locations and sizes into HARP.
8. Modeling grid set to 2000 m at 50 m increments for a total of 6,625 receptors.

Maximum residential cancer risks and noncancer hazards determined in the original AFC, amended AFC, and in the HARP analysis conducted by staff are summarized in **Public Health** Table 1.

Figure HRA-1 of the appendices to the project owner's amendment illustrates that the area expected to have cancer risk above one in one million is located on hill tops south of the project site. Staff's analysis shows a similar location in which the maximum off-site cancer risk occurs south of the facility yet is below one in one million. However, it should be noted that the difference in the calculated maximum off-site cancer risk between the project owner's method and staff's method is negligible, amounting to only 0.43 in one million and both are far below the 10 in one million significance threshold.

The major contributor to risk as determined by staff in the HARP analysis was due to emergency fire pump emissions (mostly to diesel particulates). On the other hand, the major contributor to risk determined by the project owner was due mostly to turbine emissions. Both assessments determined that no significant risk to public health would exist from any source at the power plant.

As **Public Health** Table 1 shows, the project owner's and staff's estimated acute and chronic hazard indices for the amended project are under 1.0, indicating that no short- or long-term adverse health effects are expected. The amended project's estimated cancer risk is below the significance level of 10 in one million as calculated by both the project owner and the staff. (Staff's results shown in **bold** and original project results are shown in parentheses.)

Public Health Table 1
Operation Hazard/Risk for the Amended IEEC

Type of Hazard/Risk	Hazard Index/Risk	Significance Level	Significant?
ACUTE NONCANCER	0.112 **0.05** *(0.06)*	1.0	No
CHRONIC NONCANCER	0.046 **0.009** *(0.048)*	1.0	No
INDIVIDUAL CANCER	$1.4x10^{-6}$ **0.97×10^{-6}** *($0.28X10^{-6}$)*	10.0×10^{-6}	No

Source: IEEC Amendment No. 1, Table 3.8-6.; **staff analysis in bold,** original project results in parentheses

Cooling Tower

The new design features two 8-cell cooling towers in place of the original 14-cell tower. Staff believes that this is an insignificant change and with the implementation of existing Condition of Certification **Public Health-1**, the project will not pose a significant impact to public health from the cooling towers.

Cumulative Impacts

The maximum cancer risk for the amended IEEC facility as calculated by the project owner is 1.41 in one million and as calculated by staff is 0.97 in one million. The maximum impact occurs where pollutant concentrations from IEEC would theoretically be the highest. Even at this location, staff does not expect any significant change in lifetime risk to any person, and the increase does not represent any real contribution to the average lifetime cancer risk of 250,000 in one million. Modeled facility-related residential risks are lower at more distant locations and actual risks are expected to be much lower since worst-case estimates are based on conservative assumptions, and overstate the true magnitude of the risk expected. Therefore, staff does not consider the incremental impact of the additional risk posed by the IEEC project to be either significant or cumulatively considerable.

The worst-case long-term noncancer health impact from IEEC (0.046 hazard index) is well below the significance level of 1.0 at the location of maximum impact. At this level, staff does not expect any cumulative health impacts to be significant. As with cancer risk, long-term hazard would be lower at all other locations and cumulative impacts at other locations would also be less than significant.

Even in the unlikely event that worst-case emissions from an existing facility were to coincide both geographically and temporally with IEEC emissions at the location of maximum impact, the overall health risk would not change for anyone. Thus, the IEEC project will not result in any significant cumulative cancer or chronic noncancer health impacts.

CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the amended IEEC project, and does not expect any significant adverse cancer, or short- or long-term noncancer health effects from project emissions.

The increased carcinogenic risk attributed to this project is considered to be less than significant since it is below staff's significance threshold of 10.0 in one million. The acute and chronic hazards attributed to the emission of non-carcinogenic air contaminants are considered to be less than significant since they are below staff's significance threshold of 1.0. Additionally, the IEEC facility is in compliance with the health risk significance levels of the South Coast Air Quality Management District.

REFERENCES

CALPINE (Calpine Corporation/Hatfield). 2001a. Inland Empire Energy Center, Application for Certification. Submitted to the California Energy Commission, August 17, 2001.

CALPINE (Calpine Corporation/Hatfield). 2002a. Response to data requests made by CEC staff at a workshop for the Inland Empire Energy Center Project on February 26, 2002. Submitted to the California Energy Commission, April 15, 2002.

FWEC (Foster Wheeler Environmental Corp/Booth). 2002d. Workshop Responses to CEC Staff Workshop Data Requests February 26, 2002. Submitted to the California Energy Commission, April 16, 2002.

Inland Empire Energy Center (IEEC) Amendment No. 1: GEH Technology and additional laydown area. Volumes I and II. March 2005.

POWER PLANT RELIABILITY ANALYSIS

STEVE BAKER

REQUEST

Inland Empire Energy Center, LLC requests to amend the Inland Empire Energy Center project (IEEC) to:

- Substitute two General Electric (GE) Frame 7H gas turbine/steam turbine generator trains for the two GE Frame 7F gas turbine generators and one steam turbine generator that were initially certified; and
- Add two additional temporary laydown and construction worker parking areas to the project site.

BACKGROUND

The IEEC was certified by the Energy Commission on December 17, 2003. The project incorporates the most modern, fuel efficient gas-fired generating technology then commercially available, the GE Frame 7F gas turbine generator in combined cycle.[4]

In recent years, GE has pursued development of the H-technology gas turbine. The first H machine, a 50 Hz Frame 9H unit rated at 480 MW, was installed at Baglan Bay, Wales, and began operational testing in November, 2002.[5] The first 60 Hz Frame 7H machine was ordered by Sithe Energies for installation at the Heritage Power Station in Scriba, NY, but the order was subsequently cancelled due to unfavorable economic conditions.[6]

GE proposes to install, operate and test this initial Frame 7H machine. In order to pursue this essential step in the development and marketing of this new product, GE has completed an agreement with Calpine to install the first Frame 7H machine, along with a second machine, at the IEEC. Substituting these two larger capacity machines for the Frame 7F machines initially certified necessitates this amendment.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

There are no LORS pertaining to Power Plant Reliability.

[4] A combined cycle power plant generates electricity with one or more gas turbine generators, and one or more steam turbine generators that are driven (partly or wholly) by gas turbine exhaust heat.

[5] Gas Turbine World, Summer 2003, p. 26.

[6] Power Engineering, July 2002, p. 22.

ANALYSIS

In the absence of reliability LORS, Energy Commission staff analyzes the project to determine whether it will likely be built in accordance with typical industry standards for reliability of power generation. Staff uses this level of reliability as a benchmark because it ensures that the resulting project would likely not degrade the overall reliability of the electric system it serves.

From the standpoint of reliability, the overall design of the power plant itself will be little changed from the certified project. While the two-on-two[7] combined cycle configuration differs from the two-on-one configuration of the certified project, in operation, the amended project would function much the same. In either configuration, the option exists to operate either one or both of the gas turbines. This redundancy provides a level of reliability that adequately reduces the chance that the entire power plant will be put out of service by a single equipment failure. Any difference in reliability between the certified and amended power plants will rest chiefly on the gas turbines.

The GE Frame 7H machine is brand new; none have yet been installed and operated. Therefore, it is impossible to know for certain how reliable the machine will prove to be. However, it is possible to estimate its likely reliability from two factors: its 50 Hz Frame 9H predecessor; and actual experience with the previous generation Frame 7F machines.

FRAME 9H EXPERIENCE

The first H machine, currently operating at the Baglan Bay power station in Wales, was first run in November, 2002, and has completed initial testing. While it has not been in commercial operation long enough to undergo meaningful statistical analysis, anecdotal evidence to date shows that the machine exhibits adequate reliability.

FRAME 7F EXPERIENCE

Energy Commission staff expects the Frame 7H machines proposed for the amended IEEC project to exhibit reliability at least equal to the Frame 7F machines that preceded it. GE suffered an unexpected rash of failures with the first Frame 7F machines; a combination of design, manufacturing and assembly errors resulted in GE rebuilding the entire initial fleet of 7Fs. That GE did not hesitate to solve the problems is fact. That GE learned from its experience with the 7F can be assumed.

ADDITIONAL LAYDOWN AND PARKING

The request for additional laydown and parking areas does not impact the subject of Power Plant Reliability.

[7] Two gas turbine generators and two steam turbine generators.

MITIGATION MEASURES AND CONDITIONS

The original project certification included no Reliability Conditions of Certification. Energy Commission staff believes no such conditions are warranted by the amendment, and none are proposed.

CONCLUSIONS

The requested change, from GE Frame 7F machines to GE Frame 7H machines, will likely have little or no effect on Power Plant Reliability. From this standpoint, staff recommends that the Petition be granted. This recommendation is based on the following:

1. I have analyzed the situation from the standpoint of Power Plant Reliability, and conclude there will be no new or additional significant environmental impacts associated with this action.
2. I conclude that the amendment is based on new information that was not available during the licensing proceedings.
3. I conclude that the proposed modification retains the intent of the original Commission Decision and Conditions of Certification.

SOCIOECONOMIC ANALYSIS

JOSEPH DIAMOND PH. D., ECONOMIST

REQUEST

IEEC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site.

BACKGROUND

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Socioeconomics were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified.

ANALYSIS

Energy Commission Socioeconomic staff reviewed the petition and assessed the impacts of this proposal on socioeconomics. The construction phase of the project has increased from 24 months to 26 months and a peak construction workforce has increased from 490 to 750 workers. So construction is two more months and the peak workforce has increased 260 workers. The operations workforce will rise from 22 to 33 workers or 11 workers. The labor force for Riverside-San Bernardino MSA calculated by the California Employment Development Division (EDD) in 2004 was 81,000 for the affected trades. There is ample labor supply to accommodate the IEEC project amendment and this analysis is consistent with the previous socioeconomic analysis.

The IEEC amendment will increase the economic benefits of the project because of its larger contribution to local employment and tax bases, and the local economy in terms of local purchases both during construction and operation.

CONCLUSIONS

Energy Commission Socioeconomic staff reviewed the petition and assessed the impacts of this proposal on socioeconomics. It is the Socioeconomic staff's opinion that revisions to Socioeconomic Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

SOIL AND WATER RESOURCES ANALYSIS

MARK LINDLEY AND VINCE GERONIMO

SUMMARY OF ANALYSIS

On March 11, 2005 Inland Empire Energy Center LLC submitted Amendment No. 1 to their project as described in the Commission Decision (IEEC 2003c). The project owner requests several changes to their project, most being equipment related. The project owner's requests could lead to potential impacts to Soil and Water Resources. The Staff analysis focused on:

- The Change in water demand for the site based on the project owner's request to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators and one steam turbine generator to a new configuration using two GE 107H Systems
- Potential impacts to Soil and Water Resources as a result of adding 9.6 acres of property adjacent to the site for a temporary construction laydown and parking area and the addition of 1.97 acres of land within the overall site boundary for temporary construction laydown and parking area.
- Potential impacts to Soil and Water Resources through the use of vegetated swales in lieu of a detention basin to treat surface runoff.

Staff has reviewed the Amendment No. 1 materials, the Commission Decision for the original Inland Empire Energy Center (01-AFC-17) dated December 22, 2003 (CEC 2003c), the Addendum to Amendment No. 1 dated May 19, 2005, and the Staff Assessment for that AFC dated May 23, 2003 (CEC 2003a). Staff spoke with a representative from the Riverside County Flood Control & Water Conservation District (RCFC&WCD) to request information (RCFC&WCD 2005). Staff has further reviewed any changes in laws, ordinances, regulations and standards (LORS), the environment, and the project. Potential environmental impacts caused by the proposed changes to the project were evaluated specifically in following areas of: Soil, Surface Hydrology, and Project Water Supply. Where the potential for impacts is identified, Staff has proposed mitigation measures to reduce the potential impacts to less than significant. Staff also recommends amending specific conditions of certification published in the Commission Decision for the amended project to comply with all applicable LORS.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The LORS referenced in the May 2003 Staff Assessment (CEC 2003a) and the December 2003 Commission Decision (CEC 2003c) are applicable to this proposed amendment. The applicable LORS can be referenced from the pertinent portion of Appendix A of the Commission Decision (CEC 2003c). Amendment No. 1 was reviewed for consistency against the current LORS.

FEDERAL

National Flood Insurance Act

The National Flood Insurance Act (42 USC § 4001 et seq.) of 1968 created the Federal Insurance Administration and made flood insurance available for the first time. The Flood Disaster Protection Act of 1973 made the purchase of flood insurance mandatory for the protection of property located in Special Flood Hazard Areas. The National Flood Insurance Program (NFIP) is a Federal program administered by Federal Emergency Management Agency (FEMA) a component of the Department of Homeland Security (DHS). NFIP enables property owners in participating communities to purchase insurance protection against losses from flooding. Participation in the NFIP is based on an agreement between local communities and the Federal Government that states if a community will adopt and enforce a floodplain management ordinance to reduce future flood risks to new construction in Special Flood Hazard Areas, the Federal Government will make flood insurance available within the community as a financial protection against flood losses.

LOCAL

Riverside County

Riverside County is a participating community in the NFIP under County Ordinance 458 (Ord. 458.12 § 1-8, 1993). This participation in the NFIP makes residents of the unincorporated parts of Riverside County eligible to purchase flood insurance. In order to participate in the NFIP and therefore make the purchase of flood insurance available to citizens of the county, the Federal Emergency Management Agency (FEMA) required the county to adopt a floodplain management regulation. The intent of the ordinance is to: 1) ensure that any new construction and/or substantial improvement within a mapped floodplain is done in a manner that reduces damage to the public and property and 2) discourage any new development within floodways. The Riverside County Flood Control and Water Conservation District (RCFC&WCD) is designated to administer the program in the western parts of the county.

The Floodplain Management Section of the RCFC&WCD is responsible for the implementation of the County's Floodplain Management regulation and portions of the NFIP regulations. As a result the FPM section reviews Separate Applications (Floodplain Management Review Cases), requests and/or reviews Conditional Letters of Map Revision (CLOMRs)[8] and Letters of Map Revision (LOMRs)[9], provides flood zone information and actively reviews and/or performs floodplain mapping or studies.

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[8] Conditional Letter of Map Revision (CLOMR) **-** This letter from FEMA provides comments on a proposed project and its resulting affect on revising a FIRM if the project is constructed. It indicates whether the project meets NFIP criteria. Documentation justifying the proposed projects impact on the floodplain within the District's jurisdiction must be reviewed and approved by the District's Floodplain Management Staff prior to being submitted to FEMA for a CLOMR. The studies consist of a number of elements including a pre-project hydraulic model that is capable of matching the existing FEMA hydraulic model and a post-project hydraulic model representing the changes the project will generate.

[9] Letter of Map Revision (LOMR) **-** Issued by FEMA with an accompanying copy of an annotated FIRM, this acknowledges changes in the base flood elevation, floodplain boundary, or floodway based on post-construction or revised conditions. LOMRs are issued upon completion of a project. Most projects obtain

The purpose of the ordinance is to protect public health and safety, public welfare and minimize public and private costs caused by flooding by regulating development within flood hazard areas. This ordinance was adopted to meet the criteria of the National Flood Insurance Program and proposes regulations that meet the requirements of the program. The ordinance regulates FEMA mapped floodplains as well as specified non-FEMA mapped floodplains.

ENVIRONMENTAL SETTING

REGIONAL AND VICINITY DESCRIPTION

The site is located in western Riverside County which consists almost entirely of agricultural lands. A few ephemeral washes are present, but most have been interrupted by railroad or road improvements. Furrows and road side ditches occasionally meet the criteria established in the U.S. Army Corps of Engineers Wetland Delineation Manual, and could be considered a wetland. Other land uses in the vicinity of the IEEC are primarily agriculture, intermixed with commercial, industrial and rural residential uses in the immediate vicinity. Medium-density residential development is concentrated in and near the community of Romoland, located approximately ¼ mile north of the site, and in Sun City located approximately three miles southwest of the site. Romoland School is located approximately ¼ mile north of the site. Major landmarks near the proposed project include Southern California Edison's Valley Substation located approximately ¾ miles east of the site, and the Burlington Northern and Santa Fe Railroad traversing diagonally along the northeast boundary of the IEEC site.

The project site is located near the towns of Romoland and Sun City, approximately six miles west of the City of Hemet, four miles east of the City of Perris, and 30-miles southeast of the City of Riverside (CEC 2003c). The site is currently under the project owner's control. The power plant and switchyard will occupy approximately 35 acres within the 47.7-acre project site as proposed in the Amendment No. 1. Currently, the site is cultivated agricultural land used for growing wheat. The new (secondary) laydown and parking area is located northwest of the project site on the west side of Antelope Road.

The linear facilities were described in the Staff Assessment (CEC 2003a). The project owner's Amendment No. 1 does not change the project's need for these offsite utility facilities.

SOIL

The addition of a 9.6-acre temporary construction laydown and parking area west of Antelope Road and the inclusion of the 1.97-acre area within the overall site increases temporary disturbance from 45.7 acres to 57.37 acres. The permanent energy facility

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a CLOMR prior to construction to ensure that the proposed facility will meet FEMA criteria. Obtaining a CLOMR is a way to guarantee that unforeseen issues do not prevent the issuance of a LOMR.

will occupy approximately 35 acres. Soil at the adjacent site is similar to the type and characteristics described in the Staff Assessment (CEC 2003a). The soil at the site is sandy loam. The erosion characteristic of this soil type is minimal.

SURFACE HYDROLOGY

The surface hydrology at the site was described in the Staff Assessment (CEC 2003a).

Amendment No. 1 requests a change to the stormwater management plan for the IEEC site proposed in the AFC and assessed during the foregoing Energy Commission's facility certification process. The project owner has requested to remove the requirement to construct a permanent detention facility and instead proposes two vegetated swales. The vegetated swales are conditional upon construction of a regional flood control channel to accept storm water runoff from the site (RCFC&WCD 2005).

RCFC&WCD documents related to the current regional flood control plan were evaluated as part of Staff assessment of the environmental setting. Staff also contacted Stuart McKibbin, Planning Division Director, at the RCFC&WCD to discuss the plan to revise the master drainage plan (RCFC&WCD 2005). The currently relevant master drainage plan to the IEEC site is the Romoland Master Drainage Plan (MDP). A copy of the MDP is provided on the RCFC&WCD website and shows the future Ethanac Wash alignment (Line A) near the IEEC site a quarter-mile south of McLaughlin Road, running parallel to it, with a base width of 35 feet, a depth of 9 feet, and designed for a flowrate of 5,180 cfs. Planners from several districts within Riverside County are in the process of establishing a Community Facilities District (CFD) to fund construction of the concrete regional flood control channel. CFD is proposing a new alignment for Line A, one that will run east to west across the southerly 100 feet of the IEEC project site. The project owner has designated a 100-foot right of way for the channel to cross the site. The channel will ultimately be owned and operated by RCFC&WCD after their acceptance of the CFD project.

The terrain slopes from the east to west across the site. Re-routing the upstream offsite stormwater runoff is an important flood protection measure for the IEEC. The shallow, offsite drainage, cut-off ditch planned within the San Jacinto Road right of way, which runs north to south along the east property boundary, will collect and pass offsite runoff to the future regional concrete flood control channel.

The FEMA FIRM illustrates Ethanac Wash, upstream, splitting into two directions at the Atchison Topeka and Santa Fe Railroad. The northerly split becomes Romoland Wash and flows toward the northwest along the north side of the railroad. The remaining flow in the Wash continues past the railroad along McLaughin Road south of the site. The unimproved Ethanac Wash has been mapped Zone A by FEMA showing the limits of the 100-year special flood hazard area at the IEEC southern property boundary. The effective date of the Riverside County FIRM (Panel 2085 of 3600) is November 20, 1996. The project owner has not provided a map that shows the proximity of the effective FEMA floodplain to the site.

PROJECT WATER SUPPLY

Amendment No. 1 changes the type of turbines used for power generation and requires additional water treatment processes and storage. Subsequently, the planned water demand for the project will change including the raw water usage during summer months.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The suite of potential impacts to soil, surface hydrology, and water resources from the construction and operation of the amended power plant are described below.

SOIL

The addition of a 9.6-acre construction laydown and parking area west of Antelope Road and the inclusion of the 1.97-acre area within the overall site increases temporary disturbance from 47.7 to 57.37 acres. Disturbing this additional 11.57 acres of land during construction could result in increased soil erosion on the disturbed area.

Appropriate Best Management Practices (BMPs) should be employed to mitigate potential erosion impacts on the 9.6-acre construction laydown and parking area. These additional areas shall be included in the SWPPP for construction activity. The construction laydown area west of Antelope Road should be included on the SWPPP's Construction Grading & Drainage Plan. The SWPPP shall adequately describe the BMPs that will be used to reduce the soil erosion during construction. A monitoring program shall be implemented through inspections to ensure the BMPs described in the erosion and sediment control plan are properly implemented and effective. Staff has recently provided comments on the project owner's draft SWPPP for construction activity, and these are available separately.

Soil compaction at the site and in the new construction laydown and parking areas will result from equipment and vehicle traffic. Soil compaction increases soil density by reducing soil pore space. This in turn reduces the ability of soil to absorb precipitation and transmit gases for respiration of soil microfauna. Soil compaction may result in increased runoff, erosion, and sedimentation. Construction BMP selection shall consider these potential soil problems. Before demobilization, the land temporarily disturbed for construction purposes shall be improved to support its future use. In the case of the new construction laydown and parking area, the base material shall be removed, contaminated soils remediated or removed, and the compacted soil cultivated to promote vegetation.

SURFACE HYDROLOGY

Staff's review of the Amendment No. 1 with respect to surface hydrology resulted in concerns related to:

- Increased stormwater runoff as a result of the project owner's request to change the permanent BMP selected to treat surface runoff from a detention basin to a vegetated swale.
- The capacity of the vegetated swales to provide water quality improvements since no preliminary design information was reviewed.

- The increased potential for flooding at the IEEC site as a result of routing Ethanac Wash through the site in a proposed regional flood control channel. This proposed condition will require FEMA review and approval to remap the special flood hazard area.
- Existing flooding hazards in the proposed 9.6-acre construction laydown and parking area west of Antelope Road.

The project owner's request to amend the project by replacing the proposed permanent detention facility with vegetated swales raises concerns related to peak flow mitigation. Staff concerns are in reaction to parts of the Project owner's earlier response to Data Requests #117, #118, #119, and #127 (IEEC 2002c). As part of these responses, the originally proposed storm water detention basin was required to meet the RCFC&WCD mitigation requirements for impacts associated with increased runoff as a result of developing the project. The detention basin was designed to provide mitigation for a wide range of storm events and contain back-to-back 100-year storms.

These concerns were resolved during Staff's phone conversation with the RCFC&WCD (RCFC&WCD 2005). The RCFC&WCD representative indicated that the IEEC Site will not be required to mitigate for increased runoff if the regional flood control channel is operational and that the Riverside County Conditions of Approval recommended in the prior AFC proceeding regarding this project have been met.

Amendment No. 1 replaces the proposed permanent detention facility with vegetated swales, which raised additional concerns related to water quality for storm water discharged from the Site. Vegetated swales must be properly designed and meticulously maintained to provide adequate sediment trapping. Selection of a BMP relies on the criteria of the contributing surface area and the types of pollutants to be treated. Once the BMP has been selected, design guidelines are governed by volume or flow criteria. The originally proposed extended detention basin requires a volume-based design where as vegetated swales require a flow-based design. Properly designed vegetated swales require a flat longitudinal slope, a wide base, low flow depths spread uniformly across the swale bottom, and healthy vegetated cover to properly trap eroded sediments.

In order to meet NPDES stormwater discharge regulations, the design volume or design flow to be treated must reduce pollutants to the Maximum Extent Practicable (MEP). The standard is the maximum extent possible taking into account equitable consideration and competing facts, including but not limited to: public health risk, environmental benefits, pollutant removal effectiveness, regulatory compliance, public acceptance, ability to implement, cost, and technical feasibility. Staff recommends that the project owner review the BMP design criteria published in the Riverside County *Stormwater Quality Best Management Practice Design Handbook* or the California Stormwater Quality Association, *Stormwater Best Management Practice Handbook for New Development and Redevelopment*. Design details for the vegetated swales shall be presented in the industrial activities SWPPP for operation of the plant required under Condition of Certification **Soil & Water 3**. In addition, since the performance of vegetated swales relies on healthy vegetated cover, a plan to inspect and maintain the swales should also be included in the industrial activities SWPPP.

Amendment No. 1 suggests that the RCFC&WCD regional flood control channel will be constructed within a 100-foot right of way on the southern portion of the IEEC property by the time IEEC begins operation. In the event the regional flood control channel is not fully operational when IEEC begins operation, the IEEC Amendment indicates that one or more detention ponds will be constructed as originally proposed to mitigate for increases in peak discharge from the site (IEEC 2005). Routing the RCFC&WCD regional flood control channel across the southern portion of the site could lead to potential flood related impacts to the IEEC site.

Stuart McKibbin at the RCFC&WCD (RCFC&WCD 2005) described the strategy of the CFD, which is being organized to construct the RCFC&WCD regional flood control channel. The CFD anticipates completing construction of the channel in 2007. The CFD plan would align the channel through the IEEC as described by the project owner in their amendment. Mr.McKibbin described the future concrete-lined flood control channel as having capacity for the 100-year peak basin runoff and indicated that upstream detention facilities will also be constructed as part of the regional plan.

The project owner also plans to route the upstream offsite stormwater runoff to the future regional flood control channel in a shallow, offsite drainage, cut-off ditch planned within the San Jacinto Road ROW. San Jacinto Road drainage ditch will be designed to carry 407 cubic feet per second according to the Amendment No. 1. This collection ditch will drain toward the future regional flood control channel that is planned to pass through the IEEC property. This regional flood control channel is not identified on the Romoland Master Drainage Plan (MDP) but is being planned by a CFD that will oversee construction of the channel. Staff recommends that the project owner anticipate that the regional flood control channel may not be constructed, as needed, to route offsite flows around the site.

Staff recommends amending Condition of Certification **Soil & Water 3** to allow the use of vegetated swales and a direct connection to the flood control channel as an option to the previously approved detention basin.

A flood mitigation fee shall be paid by the project owner in accordance with the Riverside County's Homeland/Romoland Area Drainage Plan, for the development area established in Amendment No. 1, or more specifically, as determined by the County under existing Condition of Certification **Soil & Water 8**.

The CFD plan to re-route the unimproved Ethanac Wash in a concrete channel, through the IEEC site, will require a hydraulic analysis and preparation of plans that must be submitted to FEMA to amend the effective floodplain. FEMA will require that no adjacent property will be impacted from the request to revise the effective floodplain. Staff recommends that the project owner review the CFD floodplain modification study for consistency with the IEEC Site. Provided that the planned Ethanac Wash channel is properly designed and implemented to meet all FEMA requirements, potentially significant flood related impacts will be mitigated.

Condition of Certification **Soil & Water 7** required the project owner provide the Commission with a copy of the LOMR. Staff suggests that the IEEC project owner not be required to initiate the application for the LOMR considering the project owner did not initiate the CLOMR (FEMA Case No. 00-09-706R) request. Staff recommends that as a condition of certification, the project owner shall review the regional flood control documents prepared by the CFD and submit the CLOMR to the CPM when a FEMA LOMR has been approved.

The project owner also provided a 2001 FEMA CLOMR for an unrelated project that was submitted to update the current, effective 1996 FEMA FIRM in Amendment No. 1. The CLOMR authorized fill to be placed on an offsite parcel 1.5 miles downstream of the IEEC site on Ethanac Wash and authorized a change to the basin hydrology. These two conditions were applied to the hydraulic analysis used as the basis for the CLOMR. New topography was used to delineate the results of the hydraulic model. Although this CLOMR was submitted in 2001 and may be a more accurate delineation of the 100-year floodplain, it remains a conditional map revision and FEMA has not yet formally updated the 1996 FIRM, which remains in effect. IEEC site and the secondary laydown and parking area as proposed in Amendment No. 1 are estimated to be outside of the 100-year floodplain as delineated in the current, effective 1996 FEMA FIRM.

Figure 5.4-2 from the AFC (IEEC 2001) illustrated that the project site as proposed in the AFC was outside the 100-year floodplain delineated in the 2001 CLOMR. Figure 5.4-2 from the AFC (IEEC 2001) was also compared to the site layout as proposed in Amendment No. 1 to evaluate impacts to the proposed 9.6-acre temporary construction laydown and parking area. Based on the 100-year floodplain delineated in the 2001 CLOMR, the proposed 9.6-acre temporary construction laydown and parking area will be prone to flooding. Equipment, supplies, and worker vehicles may all be exposed to flood conditions. Staff recommends the project owner meet all Riverside County criteria for grading within a floodplain so that no adjacent properties are impacted by terrain changes. Staff also recommends that the project owner post warnings to the users of the temporary area, notifying them that the lot is located within a flood zone and that the area has the potential to flood. However, if the RCFC&WCD regional flood control channel is constructed and operational prior to construction of the IEEC, these potential flood related impacts to the proposed 9.6-acre temporary construction laydown and parking area will be alleviated and the suggested mitigation measures for utilizing an area within a floodplain would not be necessary.

PROJECT WATER SUPPLY

Amendment No. 1 does not affect the project owner’s requirement stated in the Commission Decision (CEC 2003c) Condition of Certification **Soil & Water 4** to use EMWD’s recycled water system as its primary source of water for cooling, process, and landscape irrigation.

The amount of planned water use has changed slightly as a result of the project owner’s requested amendment. While the average daily use will increase from 2,474 gallons per minute (gpm) to 3,035 gpm, the maximum daily use will decline to 4,419 gpm from 5,142 gpm estimated in the AFC. Average and maximum and annual consumption will change less significantly. The new IEEC average annual usage will increase from 4,150 acre-feet estimated in the AFC to 4,180 acre-feet estimated in the Amendment. The new IEEC projected maximum annual usage will drop to 4,842 acre-feet from 4,958 acre-feet.

The raw water needs were based on the maximum annual water demands for the IEEC. Because of the reduced need for water annually, less demand will be placed on the EMWD supply source. The project owner maintains that the EMWD will likely need to supplement the recycled water with raw water to meet the District's summer demands. The project owner's estimate for raw water consumption for years 2008 through 2010 are: 232-, 92-, and 19-acre-feet, respectively. These projections comply with the Commission limits established as a Condition of Certification for **Soil & Water 5**.

The service agreement between the project owner and the EMWD will reflect the new IEEC water demand and wastewater return flows specified in Amendment No. 1 as a Condition of Certification **Soil & Water 6.**

CONCLUSIONS AND RECOMENDATIONS

Staff has concluded that the proposed IEEC project as amended will not cause any significant adverse direct, indirect, or cumulative impacts to soil and water resources and will be in compliance with LORS stated in the pertinent portion of Appendix A in the Commission Decision (CEC 2003c) and new LORS presented herein provided the conditions of certification recommended in the Commission Decision (CEC 2003c) are implemented with the following amendments.

PROPOSED AMENDMENTS TO THE CONDITIONS OF CERTIFICATION

Adoption of all the Conditions of Certification as found in the Commission Decision (CEC 2003c) are required to ensure continued compliance with LORS, and/or to ensure that impacts of Inland Empire Energy Center will not have any significant impact on the environment. Given the project owner's request to amend the project Staff recommends modifications to the following Conditions of Certification.

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SOIL & WATER 3: Prior to project commercial operation, the project owner shall submit a Notice of Intent for operation under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity to the State Water Resources Control Board (SWRCB). The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of the project. The SWPPP shall be submitted to Riverside County for review and comment, and to the CPM for review and approval. The SWPPP shall include final operating drainage design consistent with the criteria specified by the County of Riverside**, including those criteria relating to any adjacent flood control channels,** and specify BMPs and monitoring requirements for the IEEC project facilities. BMPs shall control soil erosion from drainage of storm water below the **vegetated swales or detention pond** and from storm water discharge in the eastern boundary interception ditch Conditions of Certification **BIO-7** and **BIO-8** address requirements for 401 Water Quality Certification from the Regional Water Quality Control Board and a Section 404 Permit from the Army Corps of Engineers.

Verification: No later than 60 days prior to the start of commercial operation for any project element, the SWPPP for Industrial Activity and a copy of the Notice of Intent for operating under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity filed with the SWRCB, shall be submitted by the project owner to the County of Riverside Building and Safety Department for comments, and to the CPM for approval. Approval of the SWPPP must be received from the CPM prior to commercial operation.

SOIL & WATER 7: ~~Following initiation of commercial operation,~~ ~~**the**~~ **The Ethanac Wash floodplain is located near the southern boundary of the IEEC Site. Construction of the IEEC shall remain outside of the FEMA floodplain shown on the effective Riverside County Flood Insurance Rate Map (FIRM), Panel 2085 of 3600. The project owner shall notify the CPM of any Conditional Letter of Map Revision (CLOMR) requests to modify the Ethanac Wash Floodplain. The project owner shall review the CLOMR request for potential impacts to the IEEC Site. The project owner will provide the CPM evidence that the IEEC property is protected from flooding due to floodplain modifications. The property owner shall submit to the CPM any Letter of Map Revision (LOMR) issued from FEMA resulting in a change to the effective FIRM. The project owner shall verify that the IEEC Site is outside of the special flood hazard boundary and elevated above the base flood elevations.** ~~project owner shall provide the CPM and the County of Riverside Flood Control Agency evidence of its submittal of as-built plans and related information as specified in FEMA's Conditional Letter of Map Revision (CLOMR) dated February 20, 2001 in order for FEMA to initiate a revision to the Flood Insurance Rate Map (FIRM) and Flood Insurance Study (FIS) Report. The project owner shall also submit to the CPM a copy of FEMA's Final Letter of Map Revision (LOMR).~~

Verification: ~~Within 180 days following~~ **Prior to** initiation of commercial operation of the IEEC, the project owner shall submit to the CPM ~~and the County of Riverside~~ evidence of its **review of documentation requesting changes to the Ethanac Wash Floodplain. The project owner shall copy the CPM on their acknowledgment letter to the CLOMR or LOMR applicant stating that the floodplain modification project will not impact the IEEC site.** ~~submittal of as-built plans and related information.~~ The project owner shall submit to the CPM evidence of ~~receipt of~~ the LOMR from FEMA, and a copy of the revised **or annotated** FIRM **showing the IEEC Site. The Annual Compliance Report shall report any floodplain changes that have a potential to impact the IEEC Site during operations.**

~~**SOIL & WATER 8:**~~ ~~Prior to site mobilization, the project owner shall pay a Flood Mitigation Fee in the amount assessed in accordance with Riverside County's Homeland/Romoland Area Drainage Plan (ADP) to assist in providing revenue to establish adequate community drainage facilities. The amount of the fee for industrial development shall be calculated on the basis of the prevailing Area Drainage Plan fee rate multiplied by the area of the new development.~~ ~~**The project owner shall also comply with the conditions in the Riverside**~~

~~**County Conditions of Approval described in the Conditional Use Permit (Case No. CUP03353)**~~

~~**Verification:** Prior to site mobilization, the project owner shall submit to the CPM, documentation that payment has been made to the County of Riverside for the Flood Mitigation Fee **and documentation that terms of the County's Conditions of Approval have been met.**~~

REFERENCES

CEC (California Energy Commission). 2003a. Staff Assessment for Inland Empire (01-AFC-17). May 23, 2003.

CEC (California Energy Commission). 2003c. Inland Empire Energy Center (01-AFC-17) Commission Decision. December 23, 2003.

IEEC, LLC (Inland Empire Energy Center, LLC). 2001. Inland Empire Energy Center Application for Certification (01-AFC-17). August 8, 2001.

IEEC, LLC (Inland Empire Energy Center, LLC). 2002c. Data Request Response Set #1. Dated February 13, 2002 and docketed February 13, 2002.

IEEC, LLC (Inland Empire Energy Center, LLC). 2005. *Inland Empire Energy Center (01-AFC-17) Amendment No. 1.* March 11, 2005.

Riverside (Riverside County). Conditional Use Permit, Case No. CUP03353, Conditions of Approval. Undated.

RCFC&WCD (Riverside County Flood Control and Water Conservation District) Phone conversation between Vince Geronimo representing CEC staff and Stuart McKibbin of RCFC&WCD, Planning Division on May 19, 2005.

TRAFFIC AND TRANSPORTATION ANALYSIS

JAMES ADAMS

REQUEST

IEEC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site.

BACKGROUND

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Traffic and Transportation were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified.

ANALYSIS

The amended project will require a monthly average workforce of 366 as compared to 250 noted in the original Application for Certification (AFC). This will increase the amount of vehicle traffic. The traffic analysis in the Amendment No. 1 filing estimates a one-third increase in truck traffic in a worst-case scenario. It is assumed that the peak hour travel would have the same proportion as noted in the original AFC, that is, 80 percent of the work force and 10 percent of the truck deliveries would arrive or depart during the peak period. An additional construction worker parking area would be located adjacent to Antelope Road. Construction of the power plant will take 26 months as compared to the original estimate of 24 months. Given the fact that almost all of the roads in the project vicinity are at Level of Service (LOS) A (free flowing traffic), staff believes that the increase in the project construction traffic with a longer construction period will not adversely affect the local traffic and transportation system. In addition, the increase in operation traffic generated by 33 instead of 22 employees originally envisioned will not significantly affect LOS levels on local roads or intersections.

CONCLUSION

Energy Commission Traffic and Transportation staff reviewed the petition and assessed the impacts to traffic and transportation. It is staff's opinion that revisions to Traffic and

Transportation Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

TRANSMISSION LINE SAFETY AND NUISANCE ANALYSIS

OBED ODOEMELAM, PH.D.

REQUEST

Inland Empire Energy Center (IEEC), LLC is seeking approval to modify the Inland Empire Energy Center Project by changing the previously-approved power generation configuration consisting of two GE Frame 7F combustion turbines and a steam turbine, to a proposed new configuration of two GE 107H combined-cycle systems. In addition, IEEC is requesting to add two additional temporary laydown/parking areas near the project site. The generated power would be transmitted to the Southern California Edison (SCE) power grid through the same 500 kV transmission line certified for the original project.

BACKGROUND

The 670-megawatt project was certified by the Energy Commission on December 17, 2003, and is expected to begin construction in the summer of 2005. The facility will be located near the community of Romoland, in Riverside County.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

At the time of certification, LORS applicable to Transmission Line Safety and Nuisance were identified in Staff's Final Staff Assessment. These LORS will continue to apply to the amended project, and no new LORS have been identified.

ANALYSIS

Energy Commission Transmission Line Safety and Nuisance staff reviewed the petition and assessed the impacts of this proposal on environmental quality, public health and safety. It is the Transmission Line Safety and Nuisance staff's opinion that revisions to Transmission Line Safety and Nuisance Conditions of Certification are not required and that the project as modified will not result in a significant adverse direct or cumulative impact on the environment (Title 20, California Code of Regulations, Section 1769).

TRANSMISSION SYSTEM ENGINEERING ANALYSIS

SUDATH ARACHCHIGE and MARK HESTERS

SUMMARY AND CONCLUSION

Staff reviewed the Inland Empire Energy Center (IEEC) Amendment Petition and finds that if the modified project complies with the Conditions of Certification the project will comply with all applicable LORS. The System Impact Study for the proposed project modifications identifies many transmission system overloads both with and without the IEEC. These overloads should be mitigated whether or not the IEEC is built and operated. There are no significant downstream transmission facilities that would likely be modified or built as a result of the interconnection and operation of the modified IEEC Project.

PROJECT DESCRIPTION

The applicant proposes to connect the 819 MW (790 MW net) IEEC into the 500kV bus at Southern California Edison (SCE) Valley substation. Two generating units would each be connected to a 19.5/500kV step-up transformer. The high-voltage terminals of the transformers would be connected to the new IEEC 500kV switchyard by overhead conductors (Calpine 2001a, page 3-16). The amended IEEC 500kV switchyard would be in a 500kV two-breaker radial feed configuration. The IEEC 500kV switchyard would connect to the existing SCE Valley Substation via a new 0.5 mile 500 kV transmission line using two 2156 kcmil per phase ACSR conductors.

SYSTEM IMPACT STUDY

The System Impact Study (SIS) performed by SCE consisted of Power Flow, Post Transient Voltage Stability, Transient Stability and Short Circuit Duty studies. The power flow study evaluated two system conditions;

1. A 2008 Peak Summer Load condition with maximum Eastern area generation, high East-of River/West-of-River (EOR/WOR) power flow, and high power flow into the Devers 500 kV substation, and

2. An Off-Peak Load condition with maximum Eastern area generation, High EOR/WOR power flow, and high power into the Devers 500-kV substation.

SYSTEM IMPACT STUDY RESULTS AND MITIGATION

The SIS performed by the SCE indicates that the addition of the IEEC would cause some impacts on the SCE transmission facilities during Peak and Off-Peak Load Conditions. Detailed information can be found for both Peak and Off-Peak Load Conditions on Table 1.1-1.3 and Table 2.1 to 2.3 of the SIS (Pages 15 and 17 of the SIS, May 21,2005 submitted by the SCE). SCE will conduct additional studies (Facility and Operational) to make a final determination on the need for system upgrades. Condition of Certification **TSE-1(f)** requires the submittal of the additional studies and a description of any required mitigation to the CPM. The SIS indicates that the proposed project increases overloads on many facilities; however, overloads occur without the proposed IEEC project, and staff assumes mitigation of those overloads would be the responsibility of other parties. The SIS did not identify any Post Transient or Transient Voltage stability criteria violations. The Short Circuit Study for substation evaluation identified that the addition of the modified IEEC Project would cause some increase in fault duty at 25 bulk power substations and 2 Valley-115kV substations. If the interconnection of the IEEC over stresses existing circuit breakers mitigation usually occurs within the fence line of existing substations and does not require significant downstream facilities. Based on its analysis of the SIS staff does not believe the interconnection and operation of the IEEC will require significant downstream facilities.

CONFORMANCE WITH LORS

The LORS applicable to the licensed power plant switchyard and outlet transmission line are listed in the IEEC Commission Decision (Inland Empire Energy Center, Application for Certification). Based on the results of the SIS staff concludes that system reliability LORS would be met.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the Inland Empire Energy Center AFC Amendment petition and finds that, if the modified project complies with the existing Conditions of Certification the project would comply with applicable LORS. The System Impact Study for the IEEC identifies many transmission system overloads that occur both with and without the IEEC. These overloads should be mitigated whether or not the IEEC is built and operating. There are no significant downstream transmission facilities that would likely occur as a result of the interconnection and operation of the Amended IEEC.

VISUAL RESOURCE ANALYSIS

MARK HAMBLIN

SUMMARY OF CONCLUSIONS

The Inland Empire Energy Center, LLC (IEEC) has petitioned to amend the certification for the IEEC Project to include a revised power generation design configuration, a new 9.63 acre construction worker vehicle parking area and laydown area (Secondary Construction Laydown Area), and a 1.97 acre addition (increase) to the existing Primary construction laydown area.

Staff has reviewed the amendment and concludes that the design changes proposed do not significantly alter the visual resources findings found in the Energy Commission's Decision for the IEEC in December 2003.

Staff has determined that with the implementation of the Energy Commission's conditions of certification for visual resources, and the project owner's requested modifications to Condition of Certification **VIS-3**, the construction and operation of the IEEC will not result in any significant adverse visual resource impacts.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The Energy Commission approved the Inland Empire Energy Center project on December 17, 2003. Although the County of Riverside adopted Countywide Design Standards & Guidelines on January 13, 2004, there are no new LORS associated with visual resources for this amendment not considered in the original Energy Commission Decision.

SETTING

The IEEC was approved to be located on approximately 45.8 acres located near the community of Romoland in unincorporated Riverside County. The project is proposed to be relocated approximately 80 feet south of the original site, while still occupying approximately 35 acres of the 45.8-acre site (IEEC Amendment Section 2.1.1).

The IEEC proposes to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators and one steam turbine generator to a new configuration using two GE 107H systems, and to add construction laydown areas at two new locations.

ANALYSIS

The Energy Commission approved the Inland Empire Energy Center project on December 17, 2003. The project remains subject to LORS of several local jurisdictions as found in the Energy Commission's December 2003 approval. All of the project's facilities (except the short segment of the wastewater pipeline that falls within the City of Perris) are subject to the County of Riverside's General Plan and its applicable specific plan(s), and Riverside County's Countywide Design Standards & Guidelines adopted on January 13, 2004.

A comparison of the most visibly prominent (tall) structures of the original IEEC project, and the amended IEEC project is as follows:

	original project	amended project
HRSG stacks	195 feet (height)	195 feet (height)
HRSG	108 feet	120 feet
Auxiliary boiler stack	80 feet	100 feet
Cooling tower	59' tall x 840' long	51' tall x 874' long
Recycled water tank	43 feet	40 feet
Sound wall	20 feet	22.5 feet
Standby generator stacks	10 feet	75 feet

Staff has reviewed the amendment and concludes that the proposed prominent structure changes do not significantly alter the visual resources analysis conducted for the original project. There are no new prominent structures being introduced to the project site. The proposed project changes do not introduce a project that has a significantly greater visual contrast, view blockage, or dominance than the project certified by the Energy Commission in 2003.

The existing Condition of Certification **VIS-1** pertaining to construction screening and surface restoration is applicable to the proposed 9.63 acre secondary construction laydown area. **VIS-1** states "the project site as well as staging material and equipment storage areas shall be visually screened with temporary screening fencing." The project owner has shown on Figure 2-11 Temporary Construction Facilities Plan, that the 9.63 acre Secondary Construction Laydown Area will have a fence containing visual screen fabric along the perimeter of the laydown area.

The project owner is also seeking to add 1.97 acres to the originally approved primary construction laydown area The 1.97 acres was not available for lease or purchase at the time of the original AFC process for the project. The proposed 1.97 acre laydown area will add to the already approved 2.88 acre northern laydown area. The 1.97 acre addition is already nearly enveloped within the northern laydown area. This laydown area is also subject to the **VIS-1** condition of certification.

The project owner has shown on Figure 2-11 Temporary Construction Facilities Plan, that the primary construction laydown area will have a temporary fence containing visual screen fabric along its north boundary, and that the project's construction site will also have a temporary fence containing visual screen fabric along its east property line.

The Commission Decision inadvertently transposed the identified areas (see strikeout in the **VIS-3** condition) for the landscaping plants. The project owner has requested a correction to the **VIS-3** condition (see bolded double underline).

The project owner's proposed change to condition **VIS-8** is discussed in staff's Visible Plume Modeling section below.

CONCLUSION

Staff concludes that the proposed amended project when compared to the original project would not cause adverse or significant visual impacts with the effective implementation visual resources of the conditions of certification approved by the Energy Commission in 2003. The effective implementation of the original conditions of certification would reduce adverse visual impacts from the amended project to a less than significant level, and ensure that the project complies with applicable LORS regarding visual resources. Staff also concludes that the project owner's requested word change (correction) to condition **VIS-3** is appropriate (see below).

REVISION TO EXISTING CONDITIONS OF CERTIFICATION

Delete text is shown in ~~strikethrough~~, added text **bold** and double **underlined**.

VIS-3 The project owner shall provide landscaping that is effective in screening the proposed project from views from I-215, State Route (SR)-74, Ethanac Road, Dawson Road, Almaden Lane, Spring Winds Drive, North Winds Drive, McLaughlin Road, Menifee Road, and nearby residences. Trees and other vegetation consisting of informal groupings of fast-growing evergreen species must be strategically placed and of sufficient density and height to effectively screen the majority of structural forms as soon as is reasonably practicable. The landscaping shall conform to Applicant's Revised Landscaping Plan submitted by the project owner on December 20, 2002 (Ex. 65) except for the changes indicated by italics in the following list: (1) street trees shall be planted immediately west of the project site along Antelope Road, (2) two offset rows of taller *evergreen* screening trees shall be planted on the berm to be constructed on the west side of the project site bordering Antelope Road, one row on top of the berm and one row on the west slope of the berm; (3) evergreen shrubs shall also be planted on the western berm to provide screening beneath the tree branches; (4) landscape plantings along the ~~western~~ **southern** half of the ~~southern~~ **western** boundary shall be initiated within one year of the start of construction; (5) If the Riverside County Economic Development Agency agrees to permit the project owner to incorporate planting along the southern side of SR 74 into its plans for beautification of the SR 74 corridor, the plantings in this area shall be installed at the start of construction or as soon after the start of construction as the EDA permits; and (6) informal groupings of fast-growing broadleaf evergreen trees shall be placed along all sides of the compressor station site.

The project owner shall submit a landscaping plan to the CPM for review and approval. The plan shall include:

a) 11”x17” color simulations of the proposed landscaping at five years as viewed from KOPs 2, and 5;

b) a plan view to scale depicting the project and the location of the landscape screening;

c) a detailed list of plants to be used, their size, the expected time to maturity, and the expected height at five years and at maturity; and a table showing when the screening objectives are calculated to be achieved for each of the major project structures, and the height and elevation of the features of the existing setting and the project that are factors in those calculations;

d) A description of any irrigation needed to ensure the proper growth and health of the plantings.

The planting must be completed by start of commercial operation.

Verification: ~~Prior to site mobilization and a~~**A**t least 45 days prior to installing the landscaping, the project owner shall submit the landscaping plan to the CPM for review and approval, and to Riverside County for review and comment. If the CPM notifies the project owner that revisions of the submittal are needed before the CPM will approve the submittal, within 30 days of receiving that notification the project owner shall prepare and submit to the CPM a revised submittal.

The project owner shall notify the CPM, within seven days after completing installation of the landscaping, that the landscaping is ready for inspection.

References

IEEC (Inland Empire Energy Center, LLC). 2005. Amendment No. 1. March 2005.

VISUAL PLUMES MODELING RESULTS

WILLIAM WALTERS

SUMMARY OF CONCLUSIONS

A comparison of the amended project's design modeling results with the original design modeling results indicates a somewhat greater plume potential for the new turbine/HRSGs and auxiliary boiler designs, but a nearly identical plume potential for new cooling tower design. However, the visible plume potential using the revised design remains below the significance criteria.

Staff reviewed the project owner's suggested revisions to the original Condition of Certification **VIS-8** and concludes that the revised cooling tower design flow variable proposed will be adequate to ensure that the cooling tower plumes will not cause significant visual impacts, by ensuring that the plume potential remains below the significance criteria of 20 percent of seasonal daylight clear hours. Therefore, it is also recommended that the project owner's revised design flow variable be approved.

INTRODUCTION

The following provides the assessment of the visible plumes predicted to occur from the revised design of the Inland Empire Energy Center (IEEC) Project. Staff completed a modeling analysis for the project owner's proposed unabated cooling tower, HRSGs and auxiliary boiler revised designs.

PROJECT DESCRIPTION

The project owner has proposed two adjacent linear 8-cell mechanical-draft cooling towers. The configuration of these two towers effectively creates a linear 16-cell tower; however, the two 8-cell cooling towers are designed to serve each turbine system separately. The project owner has not proposed to use any methods to abate visible plumes from the cooling towers.

The project includes two separate 7H turbine/heat recovery steam generator (HRSG) systems, each with separate exhaust stacks. The project owner has not proposed to use any methods to abate visible plumes from the HRSG exhausts.

The project also includes one 120,000 lb/hr steam (157 MMbtu/hr) auxiliary boiler, which is expected to be operated approximately 600 hours per year. The project owner has not proposed to use any methods to abate visible plumes from the auxiliary boiler exhaust.

The revisions to the project design include the change from 7F to 7H turbine technology, which increases power output and efficiency but eliminates duct firing capability. The new turbine type has somewhat different exhaust characteristics that need to be reassessed and the cooling tower and auxiliary boiler sizes and operation assumptions have also changed requiring that their plume potential be reassessed. This visible plume assessment replaces the visible plume assessment completed as part of the staff assessment of the original proposed IEEC design.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 20 percent of seasonal daytime with no rain, no fog, high visual contrast (i.e. “clear”) hours is used by staff as guidance for an initial plume impact threshold trigger, where if exceeded, the plume dimensions are determined and the Visual Resource Analyst determines the potential for significant plume impacts. The high visual contrast hours analysis methodology is provided below:

The Energy Commission has identified a “clear” sky category during which plumes have the greatest potential to cause adverse visual impacts. For projects such as this one for which the available meteorological data set categorizes sky cover in defined cloud cover increments (in this case roughly equal to clear, few scattered, scattered, broken, and overcast), staff includes in the “Clear” category a) all Clear hours plus b) half of the other hours with an unlimited ceiling height, which is equivalent to a sky opacity equal to or less than 50 percent. The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions, and when total sky cover is equal to or less than 10 percent, clouds either do not exist or they make up such a small proportion of the sky that conditions appear to be virtually clear; and b) when ceiling height is given as unlimited the opacity of sky cover is relatively low (equal to or less than 50 percent), clouds do not substantially reduce contrast with plumes; staff estimates this time as approximately half of these hours.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

COOLING TOWER DESIGN PARAMETERS

Staff evaluated the project owner’s amendment request (IEEC 2005), and performed an independent psychrometric analysis and dispersion modeling analysis. The Combustion Stack Visible Plume (CSVP) model was used to estimate the worst-case potential visible plume frequency.

Based on the stipulated cooling tower design and exhaust parameters anticipated by the project owner, the frequency of visual plumes can be estimated. The operating data for the cooling tower at 100 percent turbine load are provided in **Table 1**.

Table 1 – New Cooling Tower Operating and Exhaust Parameters

Parameter	New Cooling Tower Design Parameters
Number of Cells	16 (2 @ 1 x 8)
Stack Height	15.5 meters (51 feet)
Cell Stack Diameter	9.75 meters (32 feet)
Tower Housing Length	266. 5 meters (874 feet)
Tower Housing Width	18.9 meters (62 feet)
Minimum Design Inlet Air Flow Rate, kg/s/MW	28.4 kg/s/MW
Maximum Heat Rejection Rate, MW	405 MW

Source: amendment request (IEEC 2005)

The exhaust temperatures and saturated moisture contents were calculated for the hourly ambient conditions modeled through mass and energy balance based on the minimum design inlet air flow rate.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS RESULTS

Staff modeled the cooling tower plumes using the Combustion Stack Visible Plume (CSVP) model. **Table 2** provides the visible plume frequency results using a five-year (1997-2001) meteorological data set from March Air Force Base (AFB).

Table 2 – Staff Predicted Hours with Cooling Tower Visible Steam Plumes March Air Force Base 1997-2001 Meteorological Data

		Full Load	
	Available (hr)	**Plume (hr)**	**Percent**
All	42,385	15,384	36.3%
Daylight	21,452	4,537	21.1%
Nighttime	20,933	10,847	51.8%
Daylight No Rain/Fog	18,761	2,225	11.9%
Seasonal Daylight No Rain/Fog*	8,291	1,659	20.0%
Seasonal Daylight Clear*	3,282	473	14.4%

*Seasonal conditions occur anytime from November through April.

These modeling results confirm that the visible plume formation will mainly occur during the cold weather months, with the majority of plume formation occurring at night or early morning. The modeling results indicate that plumes would occur 14.4 percent of seasonal daylight clear hours. This is below the 20 percent threshold that would trigger a visual impact analysis. Therefore, based on this significance criterion, the cooling tower design as stipulated by the project owner in their suggested revision to Condition of Certification **VIS-8** would not cause significant visual plume impacts.

HRSG VISIBLE PLUME MODELING ANALYSIS

Staff evaluated the project owner's amendment request (IEEC 2005) and performed an independent psychrometric analysis and dispersion modeling analysis. The CSVP model was used to estimate the worst-case potential visible plume frequency.

HRSG DESIGN PARAMETERS

Based on the stack exhaust parameters anticipated by the project owner for each HRSG stack, the frequency of visual plumes can be estimated. The operating data for these stacks at full load and 50 percent turbine load are provided in **Table 3**.

Table 3 – HRSG Exhaust Parameters

	HRSG Exhaust Parameters					
Stack Ht	59.44 meters (195 feet)					
Stack Diameter	6.71 meters (22 feet)					
	Full Load			**50% Load**		
Ambient Temp	36 °F	63 °F	98 °F	36 °F	63 °F	98 °F
Ambient RH	66.1%	52.3%	27%	66.1%	52.3%	27%
Exhaust Gas Temperature	150.6 °F	165.5 °F	171.2 °F	134.4 °F	139.6 °F	146.4 °F
Moisture Content (wt%)	5.63%	5.96%	6.40%	5.43%	5.75%	5.92%
Exhaust Flow, klb/hr	4,898.8	4,723.3	4,558.2	2,809.6	2,588.1	2,397.2

Source: amendment request (IEEC 2005).

HRSG VISIBLE PLUME MODELING ANALYSIS RESULTS

Staff modeled the HRSG plumes using the CSVP model with a five-year meteorological data set from March AFB. **Table 4** provides the visible plume frequency results.

**Table 4 – Staff Predicted Hours with HRSG Visible Steam Plumes
March Air Force Base 1997-2001 Meteorological Data**

		Full Load		50% Load	
	Available (hr)	**Plume (hr)**	**Percent**	**Plume (hr)**	**Percent**
All	42,385	10,945	25.8%	16,033	37.8%
Daylight	21,452	3,111	14.5%	4,806	22.4%
Nighttime	20,933	7,834	37.4%	11,227	53.6%
Daylight No Rain/Fog	18,761	1,500	8.0%	2,400	12.8%
Seasonal Daylight No Rain/Fog*	8,291	1,317	15.9%	2,198	26.5%
Seasonal Daylight Clear	3,282	430	13.0%	661	20.1%

*Seasonal conditions occur anytime from November through April.

These results confirm that the visible plume formation will mainly occur during the cold weather months, with the majority of plume formation occurring at night or early morning.

The modeling results indicate that plumes would occur 13.0 percent of seasonal daylight clear hours for full load operations and 20.1 percent of seasonal daylight clear hours for 50 percent load operations. It is assumed that the plume frequencies for loads between full load and 50 percent load would be in between these two bounding load conditions. Further, it is assumed that low load operation will occur infrequently so the total average plume occurrence considering expected load operating profiles and downtime would be well below the 20 percent threshold that would trigger a visual impact analysis. Therefore, based on the plume frequency this significance criterion that staff uses as guidance, the HRSG design as presented by the project owner would not cause significant visual plume impacts.

AUXILIARY BOILER VISIBLE PLUME MODELING ANALYSIS RESULTS

Staff performed an independent psychrometric analysis and dispersion modeling analysis based on the project owner's amendment request (IEEC 2005). The CSVP model was used to estimate the worst-case potential plume frequency for the auxiliary boiler.

AUXILIARY BOILER DESIGN PARAMETERS

Based on the stack exhaust parameters provided by the project owner (IEEC 2005) and estimated by staff for the auxiliary boiler stack, the frequency of visual plumes can be estimated. The operating data for the auxiliary boiler are provided in **Table 5**.

Table 5 – Auxiliary Boiler Exhaust Parameters

	Auxiliary Boiler Exhaust Parameters
Stack Height	30.5 meters (100 feet)
Stack Diameter	1.22 meters (4 feet)
Exhaust H_2O wt%	11.43% (1)
Exhaust Gas Temp	325 °F (289)

Source: Amendment request (IEEC 2005)
Note(s):
1. Estimated based on the auxiliary boiler design for the East Altamont Energy Center Project.

AUXILIARY BOILER VISIBLE PLUME MODELING ANALYSIS RESULTS

Staff modeled the auxiliary boiler plumes using the CSVP model with a five-year meteorological data set from March AFB. **Table 6** provides the CSVP model visible plume frequency results.

Table 6 – Staff Predicted Hours with Auxiliary Boiler Visible Steam Plumes March Air Force Base 1997-2001 Meteorological Data

	Available (hr)	Plume (hr)	Percent
All	42,385	9,716	22.9%
Daylight	21,452	2,760	12.8%
Nighttime	20,933	6,956	33.2%
Daylight No Rain/Fog	18,761	1,304	7.0%
Seasonal Daylight No Rain/Fog*	8,291	1,163	14.0%
Seasonal Daylight Clear	3,282	382	11.6%

*Seasonal conditions occur anytime from November through April.

These results confirm that the visible plume formation will mainly occur during the cold weather months, with the majority of plume formation occurring at night or early morning. The modeling results indicate that plumes would occur 11.6 percent of seasonal daylight clear hours. This is below the 20 percent threshold that would trigger a visual impact analysis. It should be noted that these results are based on auxiliary boiler operation at all hours. The auxiliary boiler, while not restricted in its operation, is however expected to operate approximately 600 hours per year, thereby further reducing the probability of plume formation. Therefore, based on this significance criterion, the auxiliary boiler design as presented by the project owner would not cause significant visual plume impacts.

CONCLUSIONS AND RECOMMENDATIONS

Visible plumes from the proposed IEEC cooling towers, turbine/HRSGs exhausts, and auxiliary boiler are predicted to occur less than 20 percent of seasonal daylight clear hours. Therefore, no additional analysis of the project's cooling tower and turbine/HRSG plumes is required.

While the revised project design remains below the significance criteria, a comparison with the original design modeling results indicates a somewhat greater plume potential for the new turbine/HRSGs and auxiliary boiler designs, but a nearly identical plume potential for new cooling tower design.

Because the method of calculating the plume frequency has been improved, the threshold for determining whether plume frequency is significant or not has been changed from 10 percent to 20 percent of seasonal daylight clear hours. This required additional modifications to condition VIS-8.

REVISION TO EXISTING CONDITIONS OF CERTIFICATION

Deleted text is shown in ~~strikethrough~~, added text **bold** and double **underlined**.

VIS-8 The project owner shall ensure that the IEEC cooling tower is designed and operated so that the plume frequency will not increase substantially from the design as certified.

~~Prior to ordering the cooling tower, t~~**T**he project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation. The project owner shall not order the cooling tower until notified by the CPM that the following design requirements have been satisfied:

Either:

a) The cooling tower design confirms that the exhaust air flow rate per heat rejection rate:

~~1)~~ will not be less than ~~29.8~~ **28.4** kilograms per second per megawatt when ~~operating without duct firing when~~ ambient temperatures are between 32 degrees Fahrenheit and 100 degrees Fahrenheit; ~~and~~ **or**

~~2) will not be less than 18.42 kilograms per second per megawatt when operating with duct firing when ambient temperatures are between 32 degrees Fahrenheit and 100 degrees Fahrenheit; or~~

b) If the cooling tower design exhaust air flow rates per heat rejection values are reduced from the levels shown ~~in 1 or 2~~ above, the cooling tower design confirms that the plume frequency will not exceed staff's criteria for triggering a visual impact analysis (i.e., greater than ~~10%~~ **<u>20 percent</u>** of the seasonal daylight clear hours**<u>)</u>**, ~~where "clear" is defined as all hours with total sky cover equal to or less than 10 percent plus half of the hours with total sky cover 20-100 percent that have a sky opacity equal to or less than 50 percent~~.

Verification: If the project owner intends to comply under requirement (a) above, at least 30 days prior to ordering the cooling tower the project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation.

If the project owner intends to comply under requirement (b) above, at least 60 days prior to ordering the cooling tower the project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation, including revised exhaust flow, exhaust temperature, and heat rejection data to allow staff to remodel the cooling tower plume frequency. **<u>The determination of percent of seasonal daylight clear hours will be based on a definition of "clear" as all hours with total sky cover equal to or less than 10 percent plus half of the hours with total sky cover 20-100 percent that have a sky opacity equal to or less than 50 percent.</u>**

The project owner shall provide a written certification in each Annual Compliance Report to demonstrate that the cooling towers have consistently been operated within the design parameters, except as necessary to prevent damage to the cooling tower. If determined by the CPM to be necessary to ensure operational compliance, based on legitimate complaints received or physical evidence of potential non-compliant operation, the project owner shall monitor the cooling tower operating parameters in a manner and for a period as specified by the CPM. For each period that the cooling tower operation monitoring is required, the project owner shall provide to the CPM the cooling tower operating data within 30 days of the end of the monitoring period. The project owner shall include with this operating data an analysis of compliance and shall provide proposed remedial actions if compliance cannot be demonstrated.

REFERENCES

IEEC (Inland Empire Energy Center, LLC). 2005. Amendment No. 1. March 2005.

WASTE MANAGEMENT ANALYSIS

ALVIN GREENBERG, PH.D.

SUMMARY OF CONCLUSIONS

The Inland Empire Energy Center (IEEC), LLC, has petitioned to amend the certification for IEEC to include a revised power generation configuration and two new construction laydown areas. Staff has reviewed the amendment and concludes that the design changes proposed do not significantly alter the amounts and types of waste previously analyzed for the original project. Staff concludes that with the implementation of the waste management measures proposed in the original Application for Certification and the existing conditions of certification proposed by staff, management of the wastes generated during construction and operation of the IEEC with proposed modifications will not result in any significant adverse impacts.

LAWS, ORDINANCES, REGULATION, AND STANDARDS (LORS)

There are no new LORS associated with this amendment not considered in staff's original analysis of the Inland Empire Energy Center.

SETTING

The IEEC proposes to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators (CTGs) and one steam turbine generator (STG) to a new configuration using two GE 107H Systems, and to add an additional temporary area near the project site for construction worker parking and secondary laydown. The IEEC was approved to be located on approximately 45.8 acres located near the City of Romoland in unincorporated Riverside County. The entire project is proposed to be relocated approximately 80 feet south of the original site, but the proposed facility will still occupy approximately 35 acres of the 45.8-acre site (IEEC Amendment Section 2.1.1).

ANALYSIS

SITE CONDITIONS

A Phase I Environmental Site Assessment (ESA) was conducted on the proposed site by Foster Wheeler Environmental Corporation in accordance with methods prescribed by the American Society for Testing and Materials (ASTM Standard E 1527-00). The report of this assessment is dated May 14, 2001 and is included as Appendix H in the AFC (Calpine 2001a). The Phase I ESA found that the site has been either vacant or used for agriculture since before 1953. The assessment did not identify any “recognized environmental conditions” per the ASTM definition, that is, there was no evidence or record of any use, spillage or disposal of hazardous substances on the site, nor any other environmental concern that would require remedial action. Since the new proposed IEEC location is still within the original 45.8-acre parcel, staff concludes that the Phase I ESA conducted by Foster and Wheeler applies to the new location and therefore no significant contamination is expected to be encountered at the new site.

In addition to the slight relocation of the facility, a new 9.6-acre construction laydown and parking area is proposed to be located northwest of the project site. Since this area will be used only for parking and secondary laydown, staff finds that its use does not pose a significant risk of encountering contamination. Staff believes that if unanticipated environmental site issues arise during site preparation and/or construction, either at the facility site or the new laydown/parking area, existing Conditions of Certification (COCs) **WASTE-1** and **2** will ensure that these issues are handled appropriately.

WASTE GENERATION

The amounts of both hazardous and non-hazardous wastes expected to be generated during construction and operation of the revised IEEC project do not differ significantly from those originally proposed in the AFC (IEEC Amendment Section 3.3). As previously proposed, IEEC will generate an estimated 60 total tons of solid waste during construction and approximately 45 cubic yards per year during operation, along with 10 tons per year of metal waste. Additionally, it will produce approximately 2,575 gallons of waste oil each year, 9,480 gallons of CTG wash waste each year, 140,000 gallons of HRSG cleaning waste once every 10 years, and 70,000 pounds of SCR catalyst once every 3 to 5 years (Calpine 2001a Section 5.13).

Capacity is available in a variety of disposal facilities to accommodate the wastes resulting from the IEEC project. Table 5.13-2 of the AFC (Calpine 2001a) lists three Class III facilities that will accept nonhazardous solid wastes from the IEEC project, and Section 5.13.2.2 of the AFC discusses the three Class I landfills in California that are permitted to accept hazardous waste. In addition, the applicant has stated that recycling efforts will be prioritized wherever practical to minimize the quantities of waste requiring disposal. Since the impacts of this amendment are the same as those previously analyzed, staff finds that with the implementation of the Applicant’s proposed mitigation (described in the original AFC) and staff’s existing Conditions of Certification, the project would not result in a significant waste management impact.

CONCLUSIONS

Staff has reviewed the amendment and concluded that the design changes proposed would not alter the amounts and types of waste expected to be generated by the original project. Staff concludes that with the implementation of the waste management measures proposed in the original Application for Certification and the existing conditions of certification, management of the wastes generated during construction and operation of the IEEC with the proposed modifications will not result in any significant adverse impacts.

REFERENCES

CALPINE (Calpine Corporation/Hatfield). 2001a. Inland Empire Energy Center, Application for Certification. Submitted to the California Energy Commission, August 17, 2001.

Inland Empire Energy Center (IEEC) Amendment No. 1: GEH Technology and additional laydown area. Volumes I and II. March 2005

WORKER SAFETY AND FIRE PROTECTION ANALYSIS

ALVIN GREENBERG, PH.D.

SUMMARY OF CONCLUSIONS

The Inland Empire Energy Center, LLC (IEEC), has petitioned to amend the certification for IEEC to include a revised power generation configuration and twoa new construction laydown areas. Staff has reviewed the amendment and concluded that the design changes proposed do not significantly alter the types of hazards associated with the original project. Staff finds that with the implementation of the worker safety and fire protection measures proposed by the project owner in the original Application for Certification, the existing conditions of certification proposed by staff, and two new standard Conditions of Certification proposed by staff to ensure the protection of worker safety and health, construction and operation of the IEEC with the proposed modifications will not result in any significant adverse worker safety or fire protection impacts. Staff concludes that the project will incorporate sufficient measures to ensure adequate levels of industrial safety, and comply with applicable LORS and that the proposed project will not have significant impacts on local fire protection services.

LAWS, ORDINANCES, REGULATION, AND STANDARDS (LORS)

There are no new LORS associated with this amendment not considered in staff's original analysis of the Inland Empire Energy Center.

SETTING

The IEEC proposes to change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators (CTGs) and one steam turbine generator (STG) to a new configuration using two GE 107H Systems, and to add two additional temporary areas for construction worker parking and secondary laydown. The IEEC was approved to be located on approximately 45.8 acres located near the City of Romoland in unincorporated Riverside County. The entire project is proposed to be relocated approximately 80 feet south of the original site, while still occupying approximately 35 acres of the 45.8-acre site (IEEC Amendment Section 2.1.1).

ANALYSIS

The changes proposed to IEEC do not significantly alter the types of hazards workers are exposed to or the risk of fire and explosion, nor do they alter the fire protection services provided by the local fire department. The project owner stated that all workers will undergo proper training that will reduce or eliminate any impacts resulting from the design modifications that would be different than those analyzed by staff in the original proceedings (IEEC Amendment Section 3.14). Staff has determined that with the implementation of the training programs described in the Application for Certification, the Conditions of Certification adopted by the Commission, and two additional proposed Conditions of Certification recently developed by staff and proposed for other projects currently undergoing site certification, worker safety and fire protection impacts would be properly mitigated.

ADDITIONAL PROPOSED WORKER SAFETY MITIGATION MEASURES

Background

Protecting construction workers from injury and disease is among the greatest challenges in occupational safety and health. The following facts are reported by the National Institute for Occupational Safety and Health (NIOSH):

- More than 7 million persons work in the construction industry, representing 6% of the labor force. Approximately 1.5 million of these workers are self-employed.
- Of approximately 600,000 construction companies, 90% employ fewer than 20 workers. Few have formal safety and health programs.
- From 1980-1993, an average of 1,079 construction workers were killed on the job each year, more fatal injuries than in any other industry.
- Falls caused 3,859 construction worker fatalities (25.6%) between 1980 and 1993.
- 15% of workers' compensation costs are spent on construction injuries.
- Assuring safety and health in construction is complex, involving short-term work sites, changing hazards, and multiple operations and crews working in close proximity.
- In 1990, Congress directed NIOSH to undertake research and training to reduce diseases and injuries among construction workers in the United States. Under this mandate, NIOSH funds both intramural and extramural research projects.

The hazards associated with the construction industry are thus well documented. These hazards increase in complexity in the multi-employer worksites typical of large complex industrial type projects such as the construction of gas-fired power plants. In order to reduce and/or eliminate these hazards, it has become standard industry practice to hire a Construction Safety Supervisor to ensure a safe and healthful environment for all personnel. This has been evident in the audits of power plants under construction recently conducted by the staff. The Federal Occupational Safety and Health Administration has also entered into strategic alliances with several professional and trade organizations to promote and recognize safety professionals trained as Construction Safety Supervisors, Construction Health and Safety Officers, and other professional designations. The goal of these partnerships is to encourage construction subcontractors to improve their safety and health performance; to assist them in striving for the elimination of the four hazards (falls, electrical, caught in/between and struck-by hazards), which account for the majority of fatalities and injuries in this industry and have been the focus of targeted OSHA inspections; to prevent serious accidents in the construction industry through implementation of enhanced safety and health programs and increased employee training; and to recognize those subcontractors with exemplary safety and health programs.

To date, there are no OSHA or Cal-OSHA requirements that an employer hire or provide for a Construction Safety Officer. OSHA and Cal-OSHA regulations do, however, require that safety be provided by an employer and the term “Competent Person” is used in many OSHA and Cal-OSHA standards, documents, and directives. A “Competent Person” is usually defined by OSHA as an individual who, by way of training and/or experience, is knowledgeable of standards, is capable of identifying workplace hazards relating to the specific operations, is designated by the employer, and has authority to take appropriate action. Therefore, in order to meet the intent of the OSHA standard to provide for a safe workplace during power plant construction, staff proposes Condition of Certification **WORKER SAFETY-3** which would require the project owner/project owner to designate and provide for a power plant site Construction Safety Supervisor.

As discussed above, the hazards associated with the construction industry are well documented and increase in complexity in the multi-employer worksites typical of large complex industrial type projects such as the construction of gas-fired power plants. Accidents, fires, and a worker death have occurred at Energy Commission-certified power plants in the recent past due to project owner failure to recognize and control safety hazards and the inability to adequately supervise compliance with occupational safety and health regulations. Safety problems have been documented by Energy Commission staff in safety audits conducted in 2005 at several power plants under construction. The findings of the audit staff include, but are not limited to, such safety oversights as:

- Lack of posted confined space warning placards/signs;
- Confusing and/or inadequate electrical and machinery lockout/tagout permitting and procedures;
- Confusing and/or inappropriate procedures for handing over lockout/tagout and confined space permits to commissioning team and then to operations;
- Dangerous placement of hydraulic elevated platforms under each other;
- Inappropriate placement of fire extinguishers near hotwork;
- Dangerous placement of numerous power cords in standing water on the site thus increasing the risk of electrocution;
- Construction of an unsafe aqueous ammonia unloading pad;
- Inappropriate and unsecure placement of above-ground natural gas pipelines inside the facility but too close to the perimeter fence; and
- Lack of adequate employee or contractor written training programs addressing proper procedures to follow in the event of finding suspicious packages or objects either on- or off-site.

In order to reduce and/or eliminate these hazards, it is necessary for the Energy Commission to have a safety professional monitor on-site compliance with Cal-OSHA regulations and periodically audit safety compliance during construction, commissioning, and the hand-over to operational status. These requirements are outlined in Condition of Certification **WORKER SAFETY-4**. A monitor, hired by the project owner yet reporting to the CBO and CPM, will serve as an "extra set of eyes" to ensure that safety procedures and practices are fully implemented at all power plants certified by the Energy Commission. During the audits conducted by staff, most site safety professionals welcomed the audit team and actively engaged them in questions about the team's findings and recommendations. These safety professionals recognized that safety requires continuous vigilance and that the presence of an independent audit team provided a "fresh perspective" of the site.

CONCLUSIONS

Staff has reviewed the amendment and concluded that the design changes proposed do not significantly alter the types of risks associated with the construction and operation of the original project.

If the project owner for the proposed Inland Empire Energy Center provides a Project Construction Safety and Health Program and a Project Operations and Maintenance Safety and Health Program as required by Conditions of Certification **WORKER SAFETY-1** and **WORKER SAFETY-2**, and complies with the requirements of proposed **WORKER SAFETY-3** and **WORKER SAFETY-4**, staff believes that the project will incorporate sufficient measures to ensure adequate levels of industrial safety, and comply with applicable LORS. Staff also concludes that the proposed project will not have significant impacts on local fire protection services.

REVISIONS TO EXISTING CONDTIONS AND PROPOSED CONDITIONS OF CERTIFICATION

Added text **bold** and double **underlined.**

WORKER SAFETY-3 The project owner shall provide a site Construction Safety Supervisor (CSS) who, by way of training and/or experience, is knowledgeable of power plant construction activities and relevant laws, ordinances, regulations, and standards, is capable of identifying workplace hazards relating to the specific operations, and has authority to take appropriate action. This CSS shall have over-all authority for coordination and implementation of all occupational safety and health practices, policies, and programs. The CSS shall:

- **Verify that the safety program for the project complies with Cal/OSHA & federal regulations related to power plant projects.**
- **Verify that all construction and commissioning workers and supervisors receive adequate safety training.**

- Complete accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of safety-related incidents.
- Verify that all the plans identified in Worker Safety 1 are implemented.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit to the CPM the name and qualifications of the CSS for review and approval. The CSS shall not be replaced unless a replacement CSS is approved by the CPM.

The CSS shall submit in the Monthly Compliance Report a monthly safety inspection report to include:

- Record of all employees trained for that month (all records shall be kept on site for the duration of the project);
- Summary report of safety management actions that occurred during the month;
- Report of any continuing or unresolved situations and incidents that may pose danger to life or health;
- Report of accidents and injuries that occurred during the month.

WORKER SAFETY-4 The project owner shall employ a CPM approved Safety Monitor, who will report directly to the Chief Building Official (CB0), and who will be responsible for verifying that the Construction Safety Supervisor, as required in Worker Safety 3, implement all appropriate Cal/OSHA and Commission safety requirements specified in the Decision. The Safety Monitor shall not be replaced until the CPM approves the replacement Safety Monitor.

The CPM-approved Safety Monitor shall conduct on-site safety inspection at least once a week during construction of permanent structures, and commissioning, of the power plant unless a lesser number of inspections are approved by the CPM. The CPM may also require similar inspections concerning linear facilities.

The Safety Monitor shall keep the Chief Building Official (CBO) fully informed regarding safety related matters and coordinate with the CBO concerning on-site safety inspections, and a final safety inspection prior to issuance of the Certificate of Occupancy by the CBO. The Safety Monitor will be retained until cessation of construction and commissioning activities, and issuance of the Certificate of Occupancy, unless otherwise approved by the CPM.

The Safety Monitor(s) shall also:

- **Inform the site Construction Safety Supervisor and CBO of any construction or commissioning problems that could pose a future danger to life or health.**
- **After consultation with the CBO, have the authority to temporarily stop construction or commissioning activities involving possible safety violations or unsafe conditions that may pose an immediate or future danger to life or health, until the problem is resolved to the satisfaction of the Safety Monitor and CBO.**
- **Consult with the CBO and Construction Safety Supervisor to determine when construction may resume unless the problem is corrected immediately, and to the satisfaction of the Safety Monitor and/or CBO.**
- **Inform the CPM within 24 hours of any temporary halt in construction or commissioning activities.**
- **Be available to inspect the site whenever necessary in addition to the minimum weekly basis during construction and commissioning as determined in consultation with the CBO and CPM.**
- **Verify that all federal and Cal/OSHA requirements are practiced during the construction and installation of all permanent structures (including safety aspects of electrical installations).**

The Safety Monitor shall be qualified regarding the following:

- **Safety issues related to pipeline construction, construction equipment, and procedures, etc,**
- **LORS applicable to workplace safety and worker protection**
- **Workplace hazards typically associated with power production**
- **Lock-out / tag-out and confined spaces control systems**

Verification: The project owner shall submit the Safety Monitor(s) resume(s) to the CPM for approval at least 30 days prior to site mobilization. One or more individuals may hold this position.

REFERENCES

CALPINE (Calpine Corporation/Hatfield). 2001a. Inland Empire Energy Center, Application for Certification. Submitted to the California Energy Commission, August 17, 2001.

Inland Empire Energy Center (IEEC) Amendment No. 1: GEH Technology and additional laydown area. Volumes I and II. March 2005