Final
Determination of Compliance

Los Esteros Critical Energy Facility
Plant 13289

Combined-Cycle Conversion (Phase 2)

Bay Area Air Quality Management District
Application 8859

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FINAL DETERMINATION OF COMPLIANCE

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Background

This is the Final Determination of Compliance (FDOC) for the conversion of the existing Los Esteros Critical Energy Facility (LECEF) from simple-cycle to combined-cycle operation. This conversion is referred to as Phase 2 and involves the addition of four heat recovery steam generators, one steam turbine generator and one six-cell cooling tower.

The LECEF currently consists of four natural gas-fired LM6000PC simple-cycle combustion turbines with a combined nominal output of 180 MW, a fire pump diesel engine, and a one-cell cooling tower that is exempt from District operating permit requirements. The LECEF is a wholly owned subsidiary of the Calpine Corporation.

The proposed modified LECEF facility will have a nominal output of 320 megawatts (MW) as a result of the addition of one nominal 140 MW steam turbine generator. In addition, the maximum rated heat input of each gas turbine will increase from 472.6 MM BTU/hr (HHV) to 500 MM BTU/hr (HHV). In accordance with BAAQMD Regulation 2-2-301, the gas turbines will meet current Best Available Control Technology (BACT) standards for NOx, CO, POC, SO_2, and PM_{10} emissions. Emission reduction credits will be provided to offset emission increases of precursor organic compounds. Because the facility emissions of all regulated air pollutants will remain less than 100 tons per year each, the LECEF is not subject to Prevention of Significant Deterioration (PSD) requirements.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the PDOC for the proposed modifications to the Los Esteros Critical Energy Facility. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #8859. In accordance with Regulation 2-3-405, the BAAQMD will issue the Authority to Construct after the CEC issues its certification for the proposed modifications to the LECEF.

The PDOC describes how the proposed modified facility will comply with applicable federal, state and BAAQMD regulations, including the BACT and emission offset requirements of the District New Source Review Regulation. Permit conditions will be imposed as needed to insure continuing compliance with applicable rules and regulations and calculated air pollutant emission rates.

In accordance with BAAQMD Regulation 2, Rule 3, Sections 405 & 406, the PDOC is subject to the public notice, public inspection, and public review and comment requirements of District Regulation 2, Rule 2, Sections 406 and 407.

The initial Preliminary Determination of Compliance for the "combined-cycle" LECEF was issued on September 28, 2004. A revised PDOC was issued on March 14, 2005. The major differences between the two PDOC documents are summarized below:

- **After reviewing comments from the California Air Resources Board and EPA Region IX regarding the following permit condition that was included in the original Authority to Construct and Permit to Operate for the existing LECEF, the District has decided to conduct a BACT review for the proposed combined-cycle configuration of the LECEF.**

<u>Sunset Provision:</u> *Within three years of CEC Approval, The owner/operator must convert to either a combined cycle or cogeneration plant using BACT in effect at the time of conversion. If conversion does not occur the plant must cease operation. (Basis: California State Resources Code, Section 25552)*

- **The conclusion of the BACT review is that the combined-cycle LECEF must meet a NOx emission limit of 2.0 ppmv, dry @ 15% O_2, averaged over one-hour.**

- **The BACT review included a re-assessment of the CO emission concentration limit for the gas turbines/HRSGs that considers the decrease in the NOx limit from 2.5 to 2.0 ppmv. Consequently, the CO limit will be increased from 4 ppmv to 9 pppmv to allow for increased water injection rates at the gas turbine combustors. However, there will be no increase in the annual CO mass emission limit for the proposed combined-cycle facility.**

- **In the PDOC issued on September 28, 2004, the applicant accepted an emissions limit of 10 pounds of NOx (as NO_2) per day for each duct burner to insure that the duct burners would not trigger the BACT requirement of the District NSR Regulation. Because of the BACT determination cited above, the applicant has requested that the 10 pound per day limit be removed. Consequently, the duct burners trigger BACT since they each have a potential to emit NOx in excess of 10 pounds per day.**

- **In the PDOC issued on September 28, 2004, the applicant accepted an annual combined emissions limit of 74.9 tons of NOx (as NO_2) per year for the gas turbines and duct burners and a daily emission limit of 205.2 lb NOx/day to insure that the gas turbines would not trigger the BACT requirement of the District NSR Rule. Because of the BACT determination cited above, the applicant has requested that the original proposed combined annual NOx limit of 99.2 tons per year (as NO_2) and the proposed daily emission limit of 252.4 lb NOx/day be restored. The increases in annual and daily NOx emissions are due to duct burner firing. The quantity of emission offsets required has been changed accordingly in the revised PDOC.**

Typical Operating Scenarios:

As a municipal power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

Base Load The facility would be operated at maximum continuous output for as many hours per year as scheduled by load dispatch. During high ambient temperature periods or other periods of high demand, duct firing may be used to increase the plant output at the desired load to meet increased SVP utility system demand.

Peak Load The facility can provide additional output by duct firing the HRSG and provide additional steam to the steam turbine.

Load Following The facility would be operated to meet variable SVP load requirements. The generation would be adjusted periodically to the load demand by raising or lowering the output of the combustion turbines.

Ancillary Services The facility may operate in response to rapid California Independent System Operator (CAISO)-commanded load changes due to sale of spinning reserves or automatic load changes commanded due to sale of regulation services (Automatic Generation Control (AGC)).

Partial Shutdown At certain times of any given day and any given year, it may be necessary to shut down one gas turbine/HRSG power train. This mode of operation could generally be expected during late evening and early morning hours, when system demand may be low.

Full Shutdown This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect or market conditions.

Because several of these potential operating scenarios may result in rapid load changes that would lead to inefficient operation of the gas turbine combustors, excursion language will be included with the NOx emission concentration limit that allows for limited NOx emissions in excess of 2.0 ppmv but less than 5.0 ppmv. The number of hours allowed for these excursions is proportional to the number allowed for the recently permitted Pico Power Project.

Permitted Source Descriptions:

The modified Los Esteros Critical Energy Facility will consist of the following permitted equipment after the combined-cycle conversion has been completed:

S-1 Combustion Gas Turbine #1 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-2 Combustion Gas Turbine #2 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #3 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-4 Combustion Gas Turbine #4 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-5 Fire Pump Diesel Engine, Fairbanks Morse Model JW6H-UF40, 300 BHP, 14.5 gal/hr

S-7 Heat Recovery Steam Generator #1, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-1 Oxidation Catalyst, and A-2 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-3 Oxidation Catalyst, and A-4 Selective Catalytic Reduction System

S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-5 Oxidation Catalyst, and A-6 Selective Catalytic Reduction System

S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-7 Oxidation Catalyst, and A-8 Selective Catalytic Reduction System

S-11 Six-Cell Cooling Tower, 73,000 gallons per minute

The LECEF is currently equipped with a one-cell cooling tower for turbine inlet air and oil cooling. PM_{10} emissions from this tower are calculated to be 1.551 tons per year. This source is exempt from District permit requirements per Regulations 2-1-128.4 and 2-1-319.1, since it is not used for the evaporative cooling of process water and because the emissions are less than 5 tons per year.

As part of the Phase 2 conversion, a six-cell cooling tower with maximum PM_{10} emissions of 8 tons per year will be added. The six-cell cooling tower will require an authority to construct and permit to operate.

Emissions Control Strategy

The proposed project triggers the BACT requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (as NO_2), carbon monoxide (CO), precursor organic compounds (POC), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}). The combined-cycle LECEF will employ the following control technologies.

Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The S-1, S-2, S-3, and S-4 Gas Turbines will be equipped with water injection to reduce the combustion zone temperature and thereby reduce the formation of thermal NOx. The S-7, S-8, S-9, and S-10 HRSG duct burners will be installed downstream of the turbines but upstream of the existing oxidation catalyst and SCR system. The combined NO_x emissions from each turbine and corresponding HRSG will be reduced by a selective catalytic reduction (SCR) system with ammonia injection. In an SCR system, the nitrogen oxide emissions react with ammonia and diatomic oxygen in the presence of a precious metal catalyst to form diatomic nitrogen and water. Each gas turbine/HRSG pair will be subject to a NO_x emission concentration limit of 2.0 ppmvd @ 15% O_2 averaged over one hour.

Flue gas temperatures associated with simple-cycle gas turbines are generally higher than those of gas turbines used in combined-cycle. Simple-cycle gas turbine can have exhaust temperatures from 750^{o}F to 1100^{o}F. With combined-cycle gas turbines, exhaust heat is removed with a HRSG, resulting in stack gas temperatures ranging from 550^{o}F to 750^{o}F at the inlet to the SCR system. Because SCR catalysts perform best under defined temperature ranges, the existing high-temperature SCR catalysts will have to be replaced with conventional catalyst beds to insure satisfactory performance under the combined-cycle mode. Titanium dioxide and zeolyte catalysts are effective in the temperature range of 850^oF to 1050^oF. Vanadium pentoxide catalysts are effective in the temperature range of 550^oF to 750^oF.

Oxidation Catalyst to Minimize CO and POC Emissions

The S-1, S-2, S-3, and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs trigger BACT for CO and POC emissions. A catalyst designed to oxidize the CO and POC will be utilized to achieve a BACT-level CO emission limit of 9.0 ppmvd @ 15% O_2 (three hour average) and an annual facility cap of 98.6 tons/yr. The POC emission rate will be limited to 2.0 ppmvd @ 15 % O_2. Because CO oxidation catalysts typically operate at a higher temperature than SCR catalysts, the CO catalyst is installed upstream of the SCR system.

Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs will exclusively utilize natural gas as a fuel to minimize SO_2 and PM_{10} emissions. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

Emissions Calculations

Facility Emissions under Phase 2 (Combined-Cycle) Configuration:

The following projected operating scenario for S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10 was utilized to estimate the maximum annual air pollutant emissions from the gas turbines and HRSG duct burners. Actual operation will vary according to demand, plant maintenance, and equipment breakdowns.

- 7,260 hours of full load operation per turbine per year @ 29^oF without HRSG duct burner firing
- 1,250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29^oF
- 250 hours of start-up operation per year per gas turbine

This scenario is considered conservative because it assumes total operation of 8,760 hours per year per turbine at a minimum temperature of 29^oF. In practice, the facility operation and actual emission rates will be affected by reduced turbine load, turbine down time, and a higher average ambient operating temperature. Because the temperature of the combustion air will typically be higher than 29^oF, the air will be less dense, less natural gas will be burned, and the resulting mass emissions will be reduced accordingly.

Emission Factors:

NOx, CO, POC, and ammonia emissions will be subject to enforceable permit conditions that limit the exhaust concentration and mass emission rate for each pollutant. SO_2 and PM_{10} emissions will be subject to enforceable permit conditions that limit mass emission rates only.

Combined-Cycle Configuration (Phase 2):

Nitrogen Oxides (NOx as NO_2)

The applicant has agreed to a BACT-level NOx emission limit of 2.0 ppmv (averaged over one hour) for the combined-cycle configuration.

The NOx emissions (as NO_2) from the turbine will be limited by permit condition to 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 – 15) = 7.04 ppmv NOx, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2)/lbmol)(8600 dscf/MMBTU)
= 0.00723 lb NO_2/MMBTU

The hourly NO_2 mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.00723 lb NO_2/MM BTU)(500 MM BTU/hr) = **3.61 lb NO_2/hr**

The hourly NO_2 mass emission rate based on the maximum firing rate of a turbine and corresponding HRSG is calculated as follows:

(0.00723 lb NO_2/MM BTU)(639 MM BTU/hr) = **4.62 lb NO_2/hr**

Carbon Monoxide (CO)

The CO emission factor used to calculate **annual CO emissions** from each turbine is based upon an average CO emission concentration of 4.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(4.0 ppmvd)(20.95-0)/(20.95 – 15) = 14.08 ppmv CO, dry @ 0% O2

($14.08/10^6$)(1 lbmol/385.3 dscf)(28 lb CO)/lbmol)(8600 dscf/MMBTU)
= 0.0088 lb CO/MMBTU

The average hourly CO mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.0088 lb CO/MM BTU)(500 MM BTU/hr) = **4.4 lb CO/hr**

The average hourly CO mass emission rate based on the maximum firing rate of the turbine and corresponding HRSG is calculated as follows:

(0.0088 lb CO/MM BTU)(639 MM BTU/hr) = **5.62 lb CO/hr**

The CO emission factor used to calculate **maximum short-term CO emissions** from each turbine is based upon the permit condition limit of 9.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(9.0 ppmvd)(20.95-0)/(20.95 – 15) = 31.69 ppmv CO, dry @ 0% O2

$(31.69/10^6)$(1 lbmol/385.3 dscf)(28 lb CO)/lbmol)(8600 dscf/MMBTU)
= 0.01981 lb CO/MM BTU

The maximum hourly CO mass emission rate based on the maximum firing rate of the turbine is calculated as follows:

(0.01981 lb CO/MM BTU)(500 MM BTU/hr) = **9.9 lb CO/hr**

The maximum hourly CO mass emission rate based on the maximum firing rate of the turbine and corresponding HRSG is calculated as follows:

(0.01981 lb CO/MM BTU)(639 MM BTU/hr) = **12.66 lb CO/hr**

<u>Precursor Organic Compounds (POC)</u>

The POC emissions (as methane) from the turbine will be limited by permit condition to 2.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95-0)/(20.95 – 15) = 7.04 ppmv, dry @ 0% O2

$(7.04/10^6)$(1 lbmol/385.3 dscf)(16 lb CH_4)/lbmol)(8600 dscf/MMBTU)
= 0.0025 lb POC/MMBTU

The maximum hourly POC mass emission rate (as methane) based on the maximum firing rate of the turbine is calculated as follows:
(0.0025 lb POC/MM BTU)(500 MM BTU/hr) = **1.25 lb POC/hr**

The maximum hourly POC mass emission rate (as methane) based on the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.0025 lb POC/MM BTU)(639 MM BTU/hr) = **1.6 lb POC/hr**

<u>Sulfur Dioxide (SO_2)</u>

The SO_2 emission factor used to calculate **annual SO_2 emissions** is based upon an expected average natural gas sulfur content of 0.33 grains per 100 scf and a higher heating value of 1022 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(0.33 gr/100 scf)(10^6 BTU/MM BTU)(2 lb SO_2/lb S)(lb/7000 gr)(scf/1022 BTU)
= 0.00092 lb SO_2/MM BTU

The average hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine is calculated as follows:

(0.00092 lb SO_2/MM BTU)(500 MM BTU/hr) = **0.46 lb SO_2/hr**

The average hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.00092 lb SO_2/MM BTU)(639 MM BTU/hr) = **0.59 lb SO_2/hr**

The SO_2 emission factor used to calculate **maximum short-term SO_2 emissions** is based upon the maximum permit limit of 1.0 grains per 100 scf and a higher heating value of 1022 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(1.0 gr/100 scf)(10^6 BTU/MM BTU)(2 lb SO_2/lb S)(lb/7000 gr)(scf/1022 BTU)
= 0.0028 lb SO_2/MM BTU

The maximum hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine is calculated as follows:

(0.0028 lb SO_2/MM BTU)(500 MM BTU/hr) = **1.4 lb SO_2/hr**

The maximum hourly SO_2 mass emission rate based upon the maximum firing rate of the turbine and corresponding HRSG duct burners is calculated as follows:

(0.0028 lb SO_2/MM BTU)(639 MM BTU/hr) = **1.8 lb SO_2/hr**

PM_{10}

The PM_{10} emission factor of 2.5 lb/hr is based upon source testing results for the existing gas turbines at LECEF under simple-cycle operation. The duct burners that will be added for combined-cycle operation will not contribute significantly to the PM_{10} emissions from the gas turbines.

Ammonia (NH_3)

The ammonia (NH_3) mass emission rate from the turbines will be limited by permit condition to 10.0 ppmv, dry @ 15% O_2. The hourly NH_3 mass emission rate based on the maximum firing rate of each turbine is calculated as follows:

NH_3 emission concentration limit:	10.0 ppmv, dry @ 15% O_2
Dry exhaust gas flow rate (without duct burner):	238,868 dscfm @ 14.75% O_2
Dry exhaust gas flow rate (with duct burner):	236,649 dscfm @ 12.95% O_2

Correcting the ammonia concentration to actual oxygen content at full load without duct burner firing:

(10 ppmvd)(20.95 – 14.75)/(20.95 - 15) = 10.42 ppmvd @ 14.75% O_2

The ammonia mass emission rate at full load without duct burner firing is therefore:

(10.42 ppmvd/10^6)(238,868 dscfm)(60 min/hr)(lbmol/385.3 dscf)(17 lb NH_3/lbmol)
= **6.6 lb NH_3/hr**

The applicant has utilized a slightly higher emission factor of 6.70 lb NH_3/hr to calculate the maximum annual ammonia emissions utilized in the health risk assessment.

Based upon the maximum firing rate of the turbine, the maximum emission rate converts to the following emission factor:

(6.7 lb NH_3/hr)/(500 MM BTU/hr) = **0.134 lb NH_3/MM BTU**

Correcting the ammonia concentration to actual oxygen content at full load with duct burner firing:

(10 ppmvd)(20.95 – 12.95)/(20.95 - 15) = 13.44 ppmvd @ 12.95% O_2

The ammonia mass emission rate at full load with duct burner firing is therefore:

(13.44 ppmvd/10^6)(236,649 dscfm)(60 min/hr)(lbmol/385.3 dscf)(17 lb NH_3/lbmol)
= **8.42 lb NH_3/hr**

The applicant has utilized a slightly higher emission factor of 8.56 lb NH_3/hr to calculate the maximum annual ammonia emissions utilized in the health risk assessment.

Based upon the maximum firing rate of the turbine, the maximum emission rate converts to the following emission factor:

(8.56 lb NH_3/hr)/(639 MM BTU/hr) = **0.134 lb NH_3/MM BTU**

Table 1
Maximum Hourly Emission Factors for Combined-Cycle Configuration (lb/hour-turbine-HRSG)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Full Load without Duct Burner Firing[a]	3.61	1.25	2.5	9.9	1.4	6.7
Full Load with Duct Burner Firing[b]	4.62	1.6	2.5	12.78	1.8	8.56

[a]gas turbine at full load at maximum firing rate of 500 MM BTU/hr (HHV)

[b]gas turbine at full load with HRSG duct burner firing; maximum combined firing rate of 639 MM BTU/hour (HHV)

The gas turbine start-up/shutdown emission factors for NOx, POC and CO were provided by the applicant and based upon source testing data for the existing turbines at LECEF and similar turbines at other facilities. The emission rates for PM_{10} and SO_2 are assumed to not exceed full load emission rates since they are not affected by combustion efficiency or catalyst bed temperatures.

Table 2
Gas Turbine Start-up Emission Rates

	NO_2	POC	PM_{10}	CO	SO_2
lb/hr	40	12	2.5	41	1.4
lb/start[a]	160	48	10	164	5.6

[a]maximum start-up duration of 4 hours (240 minutes)

Maximum Daily Emissions for Gas Turbines and HRSGs:

Maximum daily emission estimates are based upon 24-hour per day operation at worst-case emission rates. For all pollutants, the maximum daily emissions occur during a day with one 4-hour start-up followed by 20 hours of full load gas turbine operation with duct burner firing at an ambient temperature of 29°F. The full load hourly emission estimates are based on the applicable permit condition emission concentration limits at 100% load. The start-up emission rates are based upon source test results from simple-cycle operation of the gas turbines at LECEF.

NO_2 = (40 lb/hr)(4 hr/start) + (4.62 lb/hr)(20 hr full load w/DB firing)
= 252.4 lb/day-turbine HRSG

CO = (41 lb/hr)(4 hr/start) + (12.78 lb/hr)(20 hr full load w/DB firing)
= 419.6 lb/day-turbine HRSG

POC = (12 lb/hr)(4 hr/start) + (1.61 lb/hr)(20 hr full load w/DB firing)
= 80.2 lb/day-turbine HRSG

PM_{10} = (2.5 lb/hr)(4 hr/start) + (2.5 lb/hr)(20 hr full load w/DB firing)
= 60 lb/day-turbine HRSG

SO_2 = (5.6 lb/hr)(4 hr/start) + (1.8 lb/hr)(20 hr full load w/DB firing)
= 58.4 lb/day-turbine HRSG

Annual Emissions For Gas Turbines and HRSGs:

The maximum annual emissions that form the basis of the permit condition limits for the four gas turbines and 4 HRSGs are based upon the following operating scenario:

- 7260 hours of full load operation per turbine per year @ 29^{o}F without HRSG duct burner firing
- 1250 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29^{o}F
- 250 hours of start-up operation per year per gas turbine

The combined NO_x (as NO_2) and CO emissions from the turbines and HRSGs will be limited by permit condition to 99 tons/year and 98.6 tons/year, respectively. The accumulated mass emission totals for NOx and CO will be monitored by the continuous emission monitor (CEM) system. The other pollutants will be monitored by annual source testing and parametric correlation, if applicable. If any part of the CEM that is used for mass emission calculations is inoperative for more than three hours of plant operation, the mass emission rates will be calculated using alternative District-approved calculation methods.

NOx (as NO_2):

[(3.61 lb/hr)(7260 hr/yr) + (4.62 lb/hr)(1250 hr/yr) + (40 lb/hr)(250 hr/yr)](4 turbines)
= 167,934.4 lb NO_2/yr
= 83.967 ton/yr

POC:

[(1.25 lb/hr)(7260 hr/yr) + (1.6 lb/hr)(1250 hr/yr) + (12 lb/hr)(250 hr/yr)](4 turbines)
= 56,300 lb/yr
= 28.15 ton/yr

PM_{10}:

[(2.5 lb/hr)(7260 hr/yr) + (2.5 lb/hr)(1250 hr/yr) + (2.5 lb/hr)(250 hr/yr)](4 turbines)
= 87,600 lb/yr
= 43.8 ton/yr

CO:

[(4.4 lb/hr)(7260 hr/yr) + (5.62 lb/hr)(1250 hr/yr) + (41 lb/hr)(250 hr/yr)](4 turbines)
= 196,876 lb/yr
= 98.438 ton/yr

SO_2:

[(0.46 lb/hr)(7260 hr/yr) + (0.59 lb/hr)(1250 hr/yr) + (0.46 lb/hr)(250 hr/yr)](4 turbines)
= 16,768.4 lb/yr
= 8.384 ton/yr

NH_3:

[(6.7 lb/hr)(7260 hr/yr) + (8.56 lb/hr)(1250 hr/yr)](4 turbines)
= 237,368 lb/yr
= 118.7 ton/yr

Table 3
Fire Pump Diesel Engine Emission Rates

	NO_x (as NO_2)	POC	PM_{10}	CO	SO_2
Fire Pump Diesel Engine					
g/bhp-hr	6.7	0.06	0.07	0.25	0.14
lb/hr[a]	3.21	0.03	0.033	0.12	0.07
ton/yr[b]	0.214	0.002	0.002	0.008	0.004

[a]engine operation for discretionary purposes is limited to 45 minutes per day; limit imposed to minimize health risk assessment impact results

[b]100 hr/yr of discretionary operation on fuel with a maximum sulfur content of 0.05% and engine rating of 290 bhp.

One-Cell Cooling Tower

The LECEF is equipped with a one-cell cooling tower that is used for auxiliary cooling and turbine inlet air chilling as required during hot days. Although the tower will only be used on hot days, the emissions calculations are based upon the worst-case assumption of 24 hr/day, 8760 hr/yr operation.

It is conservatively assumed that all particulate matter emissions are PM_{10}.

Cooling tower circulation rate:	14,150 gpm
Maximum total dissolved solids:	10,000 ppm
Drift Rate:	0.0005 %

Water mass flow rate:

(14,150 gal/min)(60 min/hr)(8.34 lb/gal) = 7,080,660 lb/hr

Cooling Tower Drift:

(7,080,660 lb/hr)(0.000005) = 35.4 lb/hr

PM_{10} = $(10{,}000/10^6)$(35.4 lb/hr)
= 0.354 lb/hr
= 8.5 lb/day (24 hr/day operation)
= 3,101 lb/yr (8,760 operating hours per year)
= 1.551 ton/yr

As a result of the conversion of the LECEF to combined-cycle operation, a larger cooling tower will be required to handle the HRSG and steam turbine blowdown.

Six-Cell Cooling Tower

It is conservatively assumed that all particulate matter emissions are PM_{10}.

Cooling tower circulation rate: 73,000 gpm
maximum total dissolved solids: 10,000 ppm
Drift Rate: 0.0005 %

Water mass flow rate:

(73,000 gal/min)(60 min/hr)(8.34 lb/gal) = 36,529,200 lb/hr

Cooling Tower Drift:

(36,529,200 lb/hr)(0.000005) = 182.65 lb/hr

PM_{10} = (10,000 ppm)(182.65 lb/hr)/(10^6)
= 1.827 lb/hr
= 43.84 lb/day (24 hr/day operation)
= 16,000 lb/yr (8,760 operating hours per year)
= 8 ton/yr

Table 4
Current Permitted Maximum Annual Facility Emissions
Simple-Cycle Configuration
(tons/yr)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Turbines	74.9	20.8	43.8	72.9	5.8	110.7
Emergency Generator	0.09	0.07	0.014	0.15	2.3E-4	0
Fire Pump Diesel Engine	0.17	0.01	0.01	0.01	0.01	0
One-Cell Cooling Tower	-	-	0.4	-	-	-
Total	**75.2**	**20.8**	**44.2**	**73.1**	**5.8**	**110.7**
Current Permit Limit	**74.9**	**20.8**	**43.8**	**72.9**	**5.8**	**110.7**

Table 5 summarizes the maximum facility criteria pollutant emissions from the new combined-cycle facility. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the four SCR Systems.

Table 5
Maximum Annual Facility[1] Emissions, Combined-Cycle Configuration (tons/yr)

	NO_2	POC	PM_{10}	CO	SO_2	NH_3
Turbines and HRSGs	83.967	28.150	43.800	98.438	8.384	118.7
Fire Pump Diesel Engine	0.214	0.002	0.002	0.008	0.004	0
One-Cell Cooling Tower	0	0	1.551	0	0	0
Six-Cell Cooling Tower	0	0	8.000	0	0	0
Total	**84.181**	**28.152**	**53.353**	**98.446**	**8.388**	**118.7**
Permit Limits	**99.2**[2]	**28.3**	**53.3**	**98.6**	**8.4**	**118**

[1]Because the natural gas fired emergency generator has been removed, it is not included in Table 5

[2]To allow for flexibility in the number of start-ups and duct firing rates, the applicant will provide sufficient emission reduction credits to offset the NOx emission increases resulting from this annual permit limit

Table 6 is a summary of the maximum toxic air contaminant (TAC) emissions from the LECEF in combined-cycle configuration. These emissions are used as input data for air pollutant dispersion models used to assess the health risk to the public resulting from TAC emissions from the facility.

Table 6
Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb/yr-project)
S-1, S-2, S-3, S-4 Gas Turbines, S-5 Fire Pump Diesel Engine, S-7, S-8, S-9, S-10 HRSGs, Exempt One-Cell Cooling Tower, S-11 Six-Cell Cooling Tower		
1,3-Butadiene[b]	7.8	1.1
Acetaldehyde[b]	721.5	72
Acrolein	65.3	3.9
Ammonia[c]	236,028	19,300
Arsenic	0	0.025
Benzene[b]	58.9	6.7
Cadmium	0	0.046
Copper	0	460
Diesel PM[b]	4.46	0.64
Ethylbenzene	576.5	193,000
Formaldehyde[b]	6,490.2	33
Hexane	4,580.3	83,000
Lead	0	16
Mercury	0	58
Naphthalene	29.4	270
Nickel[b]	72.6	0.73

Table 6
Maximum Facility Toxic Air Contaminant (TAC) Emissions (continued)

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb/yr-project)
S-1, S-2, S-3, S-4 Gas Turbines, S-5 Fire Pump Diesel Engine, S-7, S-8, S-9, S-10 HRSGs, Exempt One-Cell Cooling Tower, S-11 Six-Cell Cooling Tower		
PAHs[b]	3.2	0.044
Propylene	13,634.7	None specified
Propylene Oxide[b]	475.7	52
Toluene	2,352	38,600
Xylene	1,154.8	57,900
Zinc	1,754	6,800

[a]Pursuant to BAAQMD Toxic Risk Management Policy

[b]Carcinogenic compound

[c]Based upon the worst-case ammonia slip of 10 ppmvd @ 15% O_2 from the A-2, A-4, A-6 and A-8 SCR systems with ammonia injection

Based upon an analysis of cooling tower return water at the existing LECEF facility, no detectable amounts of arsenic, cadmium, copper, lead, or mercury were found. Therefore, it is expected that negligible quantities of those compounds will be emitted from the one-cell and six-cell cooling towers.

Compliance Determination

Regulation 2, Rule 2: New Source Review

The primary requirements of New Source Review that may apply to the proposed modifications to the Los Esteros Critical Energy Facility are Section 2-2-301, "Best Available Control Technology Requirement", and Section 2-2-302, "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR".

The proposed modifications to the LECEF are subject to BACT because, at the time Phase I was originally permitted, the applicant committed to use BACT when the LECEF was converted to a combined-cycle facility. This commitment is reflected in the final determination of compliance, authority to construct, and permit to operate for the Phase 1 (simple-cycle) Los Esteros Critical Energy Facility which included the following permit condition.

Sunset Provision: *Within three years of CEC Approval, The owner/operator must convert to either a combined cycle or cogeneration plant using BACT in effect at the time of conversion. If conversion does not occur the plant must cease operation. (Basis: California State Resources Code, Section 25552)*

The District has determined that this commitment is binding on the applicant as a permit condition contained in a District Authority to Construct.

The initial preliminary determination of compliance for the Phase 2 conversion of the LECEF issued by the District on September 28, 2004 concluded that the conversion did not trigger BACT for any pollutants because there would be no increase in emissions at the gas turbines and the potential to emit for the HRSG duct burners would be kept below 10 pounds per highest day for all pollutants. However, after reconsidering the permit condition in the Authority to Construct described above, the District has concluded that the LECEF conversion must apply BACT.

Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as “BACT 2”. This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as “BACT 1”. BACT specifications (for both the "achieved in practice" and “technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed project.

BACT for S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10 Gas Turbine/HRSG Duct Burners

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners. Because the permitted annual NOx emissions from the gas turbines will increase, they trigger the BACT provision of NSR. The HRSG duct burners will each trigger BACT for NOx because their potential to emit exceeds 10 pounds per day. It is assumed that the gas turbines and HRSGs trigger BACT for CO, POC, PM_{10}, and SO_2.

Because each gas turbine and its associated HRSG/duct burners will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/ HRSG power train as a combined unit.

The following BACT determinations for the proposed modifications to the LECEF meet or exceed the most recent recommendations adopted by the governing board of the California Air Resources Board (CARB) for large and small electric power generating power plants, as published in *Guidance for Power Plant Siting and Best Available Control Technology* (September 1999) and *Guidance for the Permitting of Electrical Generation Technologies* (July 2002).

Nitrogen Oxides (NO_x)

The LECEF is equipped with GE LM6000PC Sprint gas turbines with a nominal rating of 45 MW based upon a maximum firing rate of 472.6 MM BTU/hr. As part of the conversion to combined cycle operation, the maximum firing rate of each turbine will increase to 500 MM BTU/hr. As a result, the output of each turbine will increase to 49.4 MW. Because the permitted annual NOx emissions from the gas turbines will increase, they trigger BACT. Because the emissions from each gas turbine/HRSG duct burner power train will exhaust through a common exhaust, it is not possible to distinguish between emissions from each gas turbine versus those from the duct burner. Consequently, the increases in daily and annual emissions resulting from duct burner firing are attributed to turbines also with respect to whether or not BACT is triggered.

The simple-cycle LECEF is currently subject to a NO_x emission concentration limit of 5 ppmvd @ 15% O_2, averaged over three hours during all operating modes except gas turbine start-ups and shutdowns. The applicant originally proposed a NOx limit of 2.5 ppmvd @ 15% O_2, averaged over one hour as BACT for the combined-cycle configuration. This limit would apply to the combined exhaust from each gas turbine/HRSG power train. This limit meets the current BACT 2 (achieved in practice) determination of 2.5 ppmvd specified in District BACT Guideline 89.1.6.

The current (7/18/03) District BACT Guideline 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for combined cycle gas turbines with a rated output $\geq$ 40 MW as 2.0 ppmv NOx, dry @ 15% O_2 averaged over one hour. The guideline specifies BACT 2 (achieved in practice) as 2.5 ppmv NOx, dry @ 15% O_2, averaged over one hour with the observation that 2.0 ppmv NOx has been “achieved in practice” by a 50 MW combined cycle LM6000 sprint unit with water injection at the Valero Cogeneration Project. Based upon this BACT determination, the District issued a permit to the Pico Power Plant that included a NOx permit limit of 2.0 ppmv, dry @ 15% O_2 with limited allowable excursions due to transient situations such as rapid load changes.

This “achieved-in-practice” BACT determination was based upon the initial 3 months of operation of the Valero cogeneration unit that is subject to a NOx permit limit of 2.5 ppmv and is fired on either refinery fuel gas or natural gas. Subsequent review of 6 months of NOx CEM data from January through June of 2004 has shown that the Valero unit has not consistently complied with a NOx emission limit of 2.0 ppmv while firing refinery fuel gas. In some cases, the exceedances appear to be caused by rapid load changes at the gas turbine. In other cases, it is not clear what is causing the exceedances. However, there are several factors that could potentially cause those exceedances. One factor is that the SCR system at Valero is probably designed and operated to achieve 2.0 ppmv in order to provide a margin of compliance with the permit condition limit of 2.5 ppmv. Another factor is that refinery fuel gas typically has a higher heat content than natural gas. This results in a higher flame temperature that can result in higher NOx emissions. Because the effect of these factors cannot be definitively resolved, the achieved-in-practice BACT determination of 2.0 ppmv contained in the Pico Power Plant FDOC is considered by the District to have been made in error.

The Las Vegas Cogeneration Facility in Clark County, Nevada is equipped with 4 GE LM6000 gas turbines operating in combined-cycle mode and abated by SCR systems and oxidation catalysts. These units are permitted at emission limits of 2.0 ppmv NOx and 4.0 ppmv CO. However, a review of the NOx CEM data shows that the units are not consistently meeting the NOx concentration limit, excluding gas turbine start-ups, shutdowns, and CEM calibration periods. For example, the Unit #2 turbine exceeded the NOx limit for 16 hours during the 4th quarter of 2004, when Unit #2 operated for 2,060 hours, excluding start-ups, shutdowns, and CEM calibration periods. Units #3, #4, and #5 exceeded the NOx limit for 10, 16, and 7 hours, respectively, during the 4th quarter of 2004. It is unclear whether those “excess” hours would have been considered excursions due to transient conditions. However, it is clear that the Las Vegas turbines are not consistently meeting the 2.0 ppmv NOx limit. Based upon its review of existing data, the District has determined that a NOx limit of 2 ppm has not yet been achieved in practice. And it certainly had not been achieved in practice by February, 2004, when this application was deemed to be complete as defined by Regulation 2-1-201.

However, we can conclude that a NOx limit of 2.0 ppmv, dry averaged over one hour with limited allowable excursions due to transient conditions such as rapid load changes is technologically feasible based upon the performance of the Valero Cogeneration unit. A review of 4,009 valid clock hourly average NOx concentrations for the Valero Cogeneration Unit over a 6 month period shows that while the hourly average NOx emissions exceeded 2.0 ppmv on 514 occasions excluding start-up or other transient load conditions, the NOx concentration only exceeded 2.1 ppmv 89 times and exceeded 2.2 ppmv 42 times. This shows that the majority of exceedances were between 2.0 and 2.1 ppmv and indicates that the SCR system has been tuned to achieve a NOx emission level of 2.0 ppmv. The unit was fired on refinery fuel gas for 3,889 of those hours. When the unit was fired on natural gas (141 hours excluding start-up or transient load conditions) the NOx emission concentration did not exceed 1.9 ppmv. In addition, the CO emissions from the Valero Unit exceeded 4.0 ppmv only 7 times out of the 4,009 hours with a maximum hourly average emission concentration of 4.86 ppmv.

It is therefore reasonable to conclude that the Valero Unit is capable of achieving consistent compliance with a 2.0 ppmv NOx limit if the SCR system and water injection were tuned to comply with this emission level and if the unit was fired exclusively on natural gas.

As shown in the following table, it is also cost-effective to require this limit as calculated using District BACT cost-effectiveness calculation methods.

BACT Cost-effectiveness Calculation Summary

Case[a]	Total Annualized Cost[b] ($/year)	Emission Reduction ppmv; (tons/year)	Cost-Effectiveness ($/ton)
20 - 2.5 ppmv	$637,713	17.5 ppmv; (129.675)	$4,918
20 - 2.0 ppmv	$749,730	18 ppmv; (133.38)	$5,621

[a]assuming a NOx emission concentration from the turbine/HRSG power train prior to abatement is 20 ppmv

[b]see attached control equipment cost summary for derivation of annualized cost numbers

In conclusion, BACT for NOx for a new combined-cycle power plant employing the same size and type of gas turbine/HRSG configuration as the proposed modified Los Esteros Critical Energy Facility is deemed to be an emission concentration limit of 2.0 ppmvd, @ 15% O_2, averaged over one hour with limited allowable excursions due to transient conditions such as rapid load changes that may occur under the typical operating scenarios discussed on page 3 of this FDOC. The number of hours of excursions allowed will be proportional to those allowed for the recently permitted Pico Power Plant. This BACT determination is deemed to be technologically feasible and cost-effective in accordance with District BACT Guidelines.

The applicant has agreed to a NOx limit of 2.0 ppmvd @ 15% O_2, averaged over one hour with limited allowable excursions, not to exceed 5 ppmv. Because the water injection rate will be increased to enable the gas turbine to meet this limit, the CO emissions could potentially exceed the original BACT emission concentration limit of 4 ppmvd @ 15% O_2, averaged over 3 hours that was specified in the PDOC. Therefore, the applicant has requested a revised CO emission concentration limit of 9.0 ppmvd @ 15% O_2. This will be discussed in greater detail in the CO BACT section below.

Heat Recovery Steam Generators (HRSGs)

Supplemental heat will be supplied to the HRSGs with duct burners, which are designed to minimize NO_x emissions. The HRSG duct burners are subject to BACT since their potential to emit for NOx will exceed 10 pounds per day.

The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of 2.0 ppmvd @ 15% O_2, averaged over one hour. This satisfies BACT for NOx for this category of source.

Carbon Monoxide (CO)

The LM 6000 Sprint gas turbines at LECEF utilize conventional combustors with water injection and SCR for NOx control. For this equipment, NOx and CO emissions are inversely related. Thermal NOx production is reduced by lowering the flame temperature through the injection of water at the combustors. However, this increases CO emissions since the lower flame temperature decreases combustion efficiency. The level of CO emissions that the equipment can achieve is therefore generally dependent upon the NOx emission level that is required. Therefore, lowering NOx emissions will tend to increase peak CO emissions.

There is no achieved-in-practice BACT level for CO emissions for this type of equipment that is also subject to a 2.0 ppm NOx limit. District BACT Guideline 89.1.6, dated 7/18/03, specifies BACT (achieved in practice) for CO for a combined-cycle gas turbine with a power rating $\geq$ 40 MW as a CO emission concentration of 4.0 ppmv, dry @ 15% O_2, achieved through the use of an oxidation catalyst. However, the basis of this BACT determination is the Sacramento Power Authority's Campbell Soup Cogeneration Facility that is permitted at 4.0 ppmvd CO @ 15% O_2, averaged over 3 hours while meeting a NOx emission limit of 3 ppmvd, averaged over three hours. The Campbell Soup Facility is equipped with a 103-MW Siemens V84 gas turbine equipped with Dry Low-NOx (DLN) combustors. Because this facility uses different equipment and is subject to a higher NOx emission limit, it can achieve lower CO emissions than LECEF will be able to, and is therefore not a comparable facility for purposes of a CO BACT achieved-in-practice determination. BACT Guideline 89.1.6 is therefore not applicable to the combined-cycle LECEF that will be subject to a NOx limit of 2.0 ppm.

Moreover, the District is not aware of any other facilities that are comparable to LECEF operating with a NOx limit of 2.0 ppm that could serve as a basis for an achieved-in-practice BACT determination. The Valero Cogeneration Unit employs a LM6000 Sprint turbine with water injection and is subject to a CO limit of 6.0 ppmv. Based upon an analysis of 6 months of CEM data, the peak CO emission level was 4.86 ppmv. However, this was achieved within the context of a higher allowable NOx emission limit of 2.5 ppmv. It is expected that the peak CO emissions from the Valero Cogeneration Unit would increase and could exceed 6 ppmv if the NOx limit was reduced to 2.0 ppmv.

The Las Vegas Cogeneration project in Clark County, Nevada, uses the same equipment as LECEF and is permitted at 2.0 ppm NOx. The District has reviewed CEM data from that facility, however, and has found that it has not been consistently meeting its 2.0 ppm NOx limitation. As a result, this facility is not comparable to LECEF for purposes of an achieved-in-practice BACT determination for CO emissions.

The Sithe Mystic facility located in Everett, Massachusetts is equipped with four Mitsubishi 501G gas turbines with a nominal output of 250 MW each. They are equipped with dry Low-NOx combustors and are abated by SCR and oxidation catalysts. These units are subject to a NOx emission limit of 2 ppmv and CO emission limit of 2 ppmv. Because these turbines are approximately five times larger than the turbines employed at LECEF, they are not considered comparable for the purposes of an achieved-in-practice BACT determination.

Finally, the Pico Power Project uses similar equipment, and is permitted at a NOx limit of 2.0 ppm and a CO limit of 6.0 ppm. This project has only just recently come on-line, however, and there is insufficient data regarding its CO emissions performance to be able to make a determination that it has in fact achieved that limit in practice. This project cannot therefore be used to support an achieved-in-practice BACT determination.

Because no CO emission level has been achieved in practice for a NOx limit of 2.0 ppmv, the District must determine CO BACT based upon cost-effectiveness and technical feasibility. The District’s current cost-effectiveness criteria for CO is zero dollars per ton of CO reduced, which means that the District has determined that additional reduction of CO does not justify any additional cost. This application involves an existing source, with existing control equipment. BACT therefore requires a CO emission limit that is technologically feasible for the facility to meet on a consistent basis, without having to incur any additional costs for additional control equipment.

The applicant has provided some limited data regarding the correlation between decreasing NOx emissions and corresponding increases in CO emissions. Specifically, the applicant has looked at CO performance while increasing the water injection rate at the combustors in order to reduce NOx emissions. The data shows that as the NOx emission concentration after abatement decreased from 4.1 ppmv to 2.7 ppmv, the CO emissions after abatement by the oxidation catalyst increased from 1.7 ppmv to 5.2 ppmv. It is expected that the CO emissions will increase further as the NOx emissions approach the permitted level of 2.0 ppmv. The CO emissions limit must therefore allow for additional CO emissions to ensure that compliance with the 2.0 ppmv NOx limit is achievable. The District has determined that a 9.0 ppmv limit will provide a reasonable and appropriate margin of compliance to ensure that the facility does not violate its permit conditions, given the limited nature of the available data on which to make this BACT determination and the inexact nature of the correlation between lowering NOx emissions and increasing CO emissions. The District is not aware of any data showing that a CO limit of less than 9.0 ppmv will be achievable, and therefore cannot make a determination that BACT requires a limit less than that level.

Because the BAAQMD is in attainment for both the state and federal 1-hr and 8-hr ambient air quality standards for CO and the LECEF is not subject to PSD since the annual facility CO emission limit will remain 98.6 tons per year, increasing the short-term CO emission concentration limit from the 4.0 ppmv achieved-in-practice BACT level for higher NOx levels to 9.0 ppmv for a 2.0 NOx limit is acceptable given the corresponding air quality benefit that will be realized from the lower NOx emissions. Although the peak CO emission concentrations can be as high as 9.0 ppmv, the annual average CO emissions are not expected to exceed 4.0 ppmv. The CO emissions from the gas turbines and HRSGs will be continuously monitored and the facility will be operated to comply with the 98.6 ton per year limit on CO emissions.

The District has also performed a modeling analysis to determine the short-term impacts of CO emissions at 9 ppmv. As shown below, the 1-hr and 8-hr average CO impacts are both below District significance levels and the state and federal ambient air quality standards for CO.

Short-Term Modeled Impacts of CO Emissions at 9 ppmv

Averaging Period	Maximum Modeled Impacts ($\mu g/m^3$)	District Significance Levels ($\mu g/m^3$)	State Ambient Air Quality Standards ($\mu g/m^3$)	Federal Ambient Air Quality Standards ($\mu g/m^3$)
1-hour	85.3	2000	23,000	40,000
8-hour	57.2	500	10,000	10,000

As stated earlier, the BAAQMD is in attainment for both the state and federal ambient air quality standards for CO. The maximum ambient CO concentration recorded in the San Jose area has been trending downward. During calendar year 2003, the maximum recorded 1-hr and 8-hr average CO emission concentrations were 6,270 $\mu g/m^3$ and 4,560 $\mu g/m^3$, respectively.

Precursor Organic Compounds (POCs)

District BACT Guideline 89.1.6, dated 7/18/03, specifies BACT (achieved in practice) for POC for a combined cycle gas turbine with a power rating > 40 MW as a POC emission concentration of 2.0 ppmv, dry @ 15% O_2, typically achieved through the use of an oxidation catalyst in conjunction with combustion modifications.

Because CEMs for organic compounds only measure carbon (as C_1), it is not possible to determine non-methane/ethane hydrocarbon concentrations on a real-time basis. As a result, a continuous emission concentration limitation as BACT for POC is not feasible. Therefore, BACT for POC is deemed to be a concentration limitation to be verified by annual source testing. The POC emissions from the combustion turbine will be reduced to less than 2.0 ppmvd through the use of an oxidation catalyst. POC emissions are also minimized through the use of best combustion practices and "clean burning" natural gas.

Sulfur Dioxide (SO_2)

District BACT Guideline 89.1.6, dated 8/18/03, specifies BACT (achieved in practice) for SO_2 for a combined cycle gas turbine with a rated output > 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of 1 gr/100 scf. The gas turbines will utilize exclusively natural gas with a maximum sulfur content of 1.0 gr/100 scf to minimize SO_2 emissions. Annual emission estimates are based upon an average fuel sulfur content of 0.33 gr/100 scf. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of natural gas will result in the lowest possible emission of SO_2.

Particulate Matter (PM_{10})

District BACT Guideline 89.1.6, dated 7/18/04, specifies BACT (achieved in practice) for PM_{10} for a combined-cycle gas turbine with a rated output > 40 MW as the exclusive use of clean-burning natural gas with a sulfur content of 1 gr/100 scf. The proposed turbines will utilize natural gas exclusively with a maximum sulfur content of 1.0 gr/100 scf and an annual average sulfur content of 0.33 gr/100 scf, which will result in minimal nitrate and sulfate particulate formation. In general, PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

BACT for S-11 Six-Cell Cooling Tower

Particulate Matter (PM_{10})

The proposed six-cell cooling tower is subject to BACT for PM_{10} since its potential to emit exceeds 10 pounds per day for that pollutant.

The BAAQMD BACT/TBACT workbook does not specify BACT for PM_{10} for wet cooling towers. However, the ARB BACT Clearinghouse cites a BACT specification for PM_{10} for the proposed La Paloma power plant cooling tower as the use of drift eliminators with a maximum drift rate of 0.0006%. The cooling towers for the Los Medanos Energy Center, Delta Energy Center, Metcalf Energy Center, East Altamont Energy Center, and Tesla Power Project are or will be equipped with drift eliminators with a guaranteed drift rate of 0.0005%.

The six-cell cooling tower proposed for the combined-cycle LECEF will also be equipped with drift eliminators with a guaranteed drift rate of 0.0005%. Therefore, S-11 Cooling Tower satisfies BACT for PM_{10}.

Emission Offsets

Table 8
Permitted Maximum Annual Emissions, Combined-Cycle Configuration (tons/yr)

	NO_2	POC	CO	SO_2	PM_{10}
Current Facility Emission Permit Limits (tpy)	74.9	20.8	72.9	5.8	43.8
Combined-Cycle Facility Emission Permit Limits (tpy)	99.2	28.3	98.6	8.4	62
Emission Increase (tpy)	24.3	7.500	25.7	2.6	18.2
Offset Ratio	1.15:1.0	1.0:1.0	N/A	N/A	N/A
Offsets Required (tpy)	27.945	7.500	0	0	0

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increase associated with this project because the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 allows for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets. However, the applicant is submitting 13.370 tons per year of SO_2 offsets to partially mitigate PM_{10} emission increases from the facility pursuant to CEC requirements under CEQA.

Pursuant to Regulation 2-2-302, federally enforceable emission reduction credits are required for NOx and POC increases at a ratio of 1.15:1.0 and 1.0:1.0, respectively. As shown in Table 9, below, the applicant has demonstrated that it possesses sufficient valid NOx and POC emission reduction credits to offset the POC and NOx emission increases for this project, and will submit certificates before the Authority to Construct is issued.

As indicated below, Calpine has secured sufficient valid emission reduction credits to offset the emission increases resulting from the modifications to the existing permitted sources and new sources proposed for the Los Esteros Critical Energy Facility. These ERCs are summarized in the table below. The outstanding balance of 19.022 tons per year of POC, 283.749 tons per year of NOx, and 76.270 tons per year of SO_2 will be re-issued as new banking certificates and returned to Calpine.

Table 9 Emission Reduction Credits Identified by Calpine as of June 2, 2005 (tons/yr)

Current Owner	Certificate Number	Pollutant Quantity (tpy)			Origin, Location	Date Banked
		POC	NOx	SO_2		
Calpine	856	26.522	0	0	Myers Container, San Pablo	4/23/02
LECEF	724	0	7.100	0	Cardinal Cogen, Palo Alto	3/13/96
Calpine	896	0	305.594	90.000	PG&E Potrero Power Plant, San Francisco	4/26/84
Total Offsets Available		26.522	311.694	90.000		
Offset Obligation		7.500	27.945	13.730		
Difference		+19.022	+283.749	+76.270		
Balance		19.022	283.749	76.270		

Pursuant to District Regulation 2-2-311, the applicant must provide the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, *Power Plants*, the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant.

Prevention of Significant Deterioration (PSD)

Pursuant to Regulation 2-2-304, a PSD air quality analysis is not required because the modified LECEF will emit less than the trigger levels listed below for NO_2, POC, PM_{10}, CO, and SO_2. Therefore, the project will not be subject to PSD review for those pollutants.

Table 10
Combined-Cycle Facility Emissions and PSD Trigger Levels

Pollutant	PSD Trigger Level for New Facilities (tpy)	Phase 2 LECEF Potential to Emit (tpy)
NO_x	100	99.2
POC	100	28.3
PM_{10}	100	62.1
CO	100	98.6
SO_2	100	8.4
SAM	7	< 7

The sulfuric acid mist (SAM) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. An enforceable permit condition has been included (part 23) limiting combined sulfuric acid mist from the gas turbines and HRSGs to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in part 27 of the permit conditions, to measure SO_2, SO_3, and SAM. This approach is necessary because the extent to which fuel sulfur is converted to SO_3 and then to sulfuric acid mist when it is combusted in a gas turbine has not been established.

Regulation 2, Rule 2, Sections 406 and 407: Public Notice, Comment, and Inspection

Because the California Energy Commission has accepted an Application for Certification for this plant, the plant is subject to District Regulation 2, Rule 3 that governs power plants. Pursuant to Regulation 2-3-404, this project is subject to the Public Notice, Public Comment and Public Inspection requirements contained in Sections 2-2-406 and 407 of Rule 2. Pursuant to these regulations a notice inviting written public comment on the initial PDOC was published in the San Jose Mercury News on November 4, 2004. The notice included the preliminary decision of the APCO to issue an authority to construct for the proposed phase II modifications to the LECEF, how the public could obtain further information regarding the modifications, and invited written public comment period for a period of 30 calendar days from the date of publication. A similar notice was published in the San Jose Mercury News on March 23, 2005 inviting written public comment on the revised PDOC that was issued on March 14, 2005. Written comments were submitted to the District by the CEC, USEPA, and Michael Boyd, a private citizen. The comments were carefully considered and written responses have been sent to each commentor with a copy of the FDOC. Where appropriate, the FDOC includes changes in response to those comments.

California Environmental Quality Act (CEQA) Analysis

The CEQA requirements of District Regulation 2-1-426 are met because the California Energy Commission (CEC) is the lead agency on this project and is thus responsible for complying with CEQA. The CEC's final certification and licensure will serve as the EIR equivalent pursuant to the CEC's certified regulatory program (CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523).

BAAQMD Toxic Risk Management Policy

Pursuant to the BAAQMD Toxic Risk Management Policy (TRMP), a health risk screening analysis must be performed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the project. In accordance with the requirements of the BAAQMD TRMP and California Air Pollution Control Officers Association (CAPCOA) guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

The District's Toxics Evaluation Section performed a review of the health risk assessment submitted by the applicant for operation of the combined cycle gas turbine configuration of the LECEF. The emission rates used in that analysis are calculated based on an annual fuel use of 16,560,000 MMBTU (16,200 MMscf/yr.). The ammonia emissions rates were based upon a worst-case ammonia slip emission concentration of 10 ppmvd @ 15% O_2 from the SCR systems. The remainder of the TAC emissions, except for PAHs, hexane and propylene, were calculated using the emission factors from the AP-42 Background Document published by US-EPA in April 2000. California Air Toxics Emission Factor (CATEF II) database mean emission factors, available from the California Air Resources Board (CARB) for gas turbines with COC/SCR controls, were used for PAHs, hexane and propylene. Emissions from four gas turbines, four HRSGs, the one-cell and six-cell cooling towers, and fire pump diesel engine have been included in this risk screening analysis. The natural gas fired emergency generator was never and will not be installed and is therefore not included in the risk screening analysis.

Table 11
Risk Screening Analysis Results

Cancer Risk	Chronic Hazard Index
2.8 in one million	0.006

Pursuant to the BAAQMD Toxic Risk Management Policy (TRMP), the increased carcinogenic risk attributed to this project is acceptable since it is less than 10 in one million and TBACT is employed on all sources subject to the risk screening.

The fire pump diesel engine, which is the primary contributor to the total risk of 2.8 in one million employs TBACT since it has been CARB-certified (Executive Order U-R-004-0111) at a particulate matter emission rate of 0.1 g/bhp-hr. The gas turbines and HRSGs are abated by oxidation catalysts, which are considered TBACT for the products of incomplete combustion that are considered toxic air contaminants as listed in Table 6. The cooling towers are designed to achieve a drift rate of 0.0005% which is considered TBACT since it minimizes the emissions of carcinogenic heavy metals such as nickel.

Thus, in accordance with the BAAQMD Toxic Risk Management Policy, the screen passes.

Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the air quality impact analysis is designed to insure that the proposed facility will comply with this Regulation.

Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the applicant has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed modifications to the LECEF, including the addition of the four heat recovery steam generators.

Regulation 2, Rule 2, Section 307: Denial, Failure of All Facilities to be in Compliance

Because the proposed modifications to the LECEF do not constitute a major modification of a major facility pursuant to 2-2-221, Regulation 2-2-307 does not apply. Under its current configuration, the LECEF is not a major facility. After the proposed modifications, the "combined-cycle" LECEF will not be a major facility. Therefore, Calpine is not required to submit a certification that all of their major facilities located in the State of California are either in compliance or on a schedule of compliance with all applicable state and federal emission limitations and standards.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-405, this Final Determination of Compliance (FDOC) serves as the APCO's final decision that the proposed modified power plant will meet the requirements of all applicable BAAQMD, state and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-403, the

FDOC has satisfied the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the FDOC is not considered a final determination of whether the facility can be constructed or operated. Pursuant to Regulation 2-3-405, the authority to construct will be issued after the modified LECEF is certified by the California Energy Commission.

Regulation 2, Rule 6: Major Facility Review

Title V of the 1990 Clean Air Act Amendments (CAAA) requires states to implement and administer a source-wide operating permit program consistent with the provisions of Title 40, Code of Federal Regulations (CFR), Part 70. The BAAQMD administers the Title V program through Regulation 2, Rule 6. The Title V operating permit was issued for the existing configuration of the LECEF on June 4, 2004. Because the proposed changes to the LECEF facility constitute a major modification under Title V, a modified Title V permit must be issued prior to first fire of the combined-cycle LECEF. The owner/operator has not submitted an application to modify the Title V permit as of the date of this document.

Regulation 2, Rule 7: Acid Rain

The LECEF is a Phase II Acid Rain Facility pursuant to Regulation 2-6-217.1. The modified LECEF will also be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are set forth in 40 CFR Parts 72, 73, and 75. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72.

The project will be subject to the following general requirements under the acid rain program:

- Duty to apply for a modification to the Acid Rain Permit
- Compliance with SO_2 and NOx emission limits
- Duty to obtain required SO_2 allowances
- Duty to install, operate and certify Continuous Emission Monitoring Systems (CEMs) to demonstrate compliance with the acid rain requirements

The applicant will secure the required SO_2 allowances and will perform the required emission monitoring. In accordance with applicable federal regulations, the applicant will submit appropriate monitoring plans. The Title IV (Acid Rain) permit was issued for the existing configuration of the LECEF on June 4, 2004. Because the proposed changes to the LECEF facility constitute a major modification under Title V, a modified Title IV/V permit must be issued prior to first fire of the combined-cycle LECEF. The owner/operator has not submitted an application to modify the Title IV/V permit as of the date of this document.

Regulation 6: Particulate Matter and Visible Emissions

The combustion of natural gas at the proposed gas turbines and HRSGs is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including Sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume.

Regulation 7: **Odorous Substances**

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from each of the proposed SCR systems will be limited by permit condition to 10 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: **Organic Compounds**

The gas turbines and HRSG duct burners are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Regulation 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry.

The use of solvents for cleaning and maintenance at the TPP is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" Section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9: **Inorganic Gaseous Pollutants**

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppm (dry). The gas turbine is not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with Section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The gas turbines (each rated at 500 MM BTU/hr, HHV) and proposed HRSG duct burners (each rated at 139 MM BTU/hr, HHV) will comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition NOx emission limit of 2.0 ppmvd @ 15% O_2. The fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 1.89 MM BTU/hr, based upon a maximum diesel fuel use rate of 13.5 gallons per hour.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The 300 hp fire pump diesel engine is exempt from the requirements of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The S-5 Fire Pump Diesel Engine will continue to comply with Regulation 9-8-330 which allows unlimited emergency use and limits discretionary use to 100 hours per year.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because the combined exhaust from the combustion gas turbines and HRSG duct burners will be limited by permit condition to NO_x emissions of 2.0 ppmvd @ 15% O_2 (verified by CEM), the gas turbines will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: New Source Performance Standards (NSPS)

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60, New Source Performance Standards. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Db, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units", and Subpart GG "Standards of Performance for Stationary Gas Turbines". The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. Subpart Db applies to the heat recovery steam generators and Subpart GG applies to the gas turbines. The applicable emission limitations are summarized below:

Applicable New Source Performance Standards

Source	Requirement	Emission Limitation	Compliance Verification
Gas Turbines and HRSGs	Subpart Db		
	40 CFR 60.44b(a)(1)(ii)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 2.0 ppmvd @15% O_2. This is equivalent to 0.00723 lb NOx/MM BTU
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Gas Turbines limited by permit condition to 2.0 ppmv NOx @ 15% O_2, dry, verified by CEM

Section 112 of the Clean Air Act, National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Gas Turbines, which was promulgated on March 5, 2004, does not apply to the proposed modified LECEF since it was constructed prior to 1/14/03 and the proposed combined-cycle conversion of the existing gas turbines at the LECEF does not constitute a "reconstruction" of the gas turbines because the conversion does not involve the replacement of any components of the turbines. This definition of "Reconstruction" is given in 40 CFR Part 63, Subpart A, Section 63.2, "Definitions".

CEQA

The CEQA requirements of Districts Regulation 2-1-426 are met because the California Energy (CEC) is the lead agency on this project. The CEC is thus responsible for conducting the CEQA review and preparing the CEQA document for this project. The CEC's final certification and license will serve as the EIR equivalent pursuant to the CEC's certified regulatory program as specified in CEQA Guidelines Section 15253(b) and Public Resources Code Sections 21080.5 and 25523.

Permit Conditions (Combined-Cycle Configuration)

<u>Definitions:</u>

Clock Hour:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf.
Firing Hours:	Period of time, during which fuel is flowing to a unit, measured in fifteen-minute increments.
MM BTU:	million British thermal units
Gas Turbine Start-up Mode:	The time beginning with the introduction of continuous fuel flow to the Gas Turbine until the requirements listed in Part 19 are satisfied. In no case shall the duration of a start-up exceed 240 minutes.
Gas Turbine Shutdown Mode:	The time from non-compliance with any requirement listed in part 19 until termination of fuel flow to the Gas Turbine, but not to exceed 30 minutes.
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO or NH_3) corrected to a standard stack gas oxygen concentration. For an emission point (exhaust of a Gas Turbine) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired following the installation of the duct burners and associated equipment, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange. The Commissioning Period shall not exceed 180 days under any circumstances.
Alternate Calculation:	A District approved calculation used to calculate mass emission data during a period when the CEM or other monitoring system is not capable of calculating mass emissions.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

<u>EQUIPMENT DESCRIPTION</u>:

This Authority To Construct Is Issued And Is Valid For This Equipment Only While It Is In The Configuration Set Forth In The Following Description:

Four Combined-Cycle Gas Turbine Generator Power Trains consisting of:

1. Combined-Cycle Gas Turbine, General Electric LM6000PC, Maximum Heat Input 500 MMBTU/hr (HHV), 49.4 MW, Natural Gas-Fired

2. Heat Recovery Steam Generator, equipped with low-NOx duct burners, 139 MM BTU/hour, natural gas fired

3. Selective Catalytic Reduction (SCR) NOx Control System.

4. Ammonia Injection System.
(including the ammonia storage tank and control system)

5. Oxidation Catalyst (OC) System.

6. Continuous emission monitoring system (CEMS) designed to continuously record the measured gaseous concentrations, and calculate and continuously monitor and record the NOx and CO concentrations in ppmvd corrected to 15% oxygen on a dry basis. The CEM shall also calculate, using District approved methods, and log any mass limits required by these conditions.

PERMIT CONDITIONS:

Conditions for the Commissioning Period

1. The owner/operator of the Los Esteros Critical Energy Facility shall minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators to the maximum extent possible during the commissioning period. Parts 1 through 11 shall only apply during the commissioning period as defined above. Unless noted, parts 12 through 49 shall only apply after the commissioning period has ended. (basis: cumulative increase)

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1, S-2, S-3 and S-4 Gas Turbine combustors to minimize the emissions of carbon monoxide and nitrogen oxides. (basis: cumulative increase)

3. At the earliest feasible opportunity and in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall install, adjust and operate the SCR Systems (A-2, A-4, A-6 & A-8) and OC Systems (A-1, A-3, A-5 & A-7) to minimize the emissions of nitrogen oxides and carbon monoxide from S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators. (basis: cumulative increase)

4. Coincident with the steady-state operation of SCR Systems (A-2, A-4, A-6, & A-8) and OC Systems (A-1, A-3, A-5, & A-7) pursuant to part 3, the owner/operator shall operate the facility in such a manner that the Gas Turbines (S-1, S-2, S-3 and S-4) comply with the NOx and CO emission limitations specified in parts 19a and 19c. (basis: BACT, offsets)

5. The owner/operator of the Los Esteros Critical Energy Facility shall submit a plan to the District Permit Services Division at least two weeks prior to first firing of S-1, S-2, S-3 & S-4 Gas Turbines and/or S-7, S-8, S-9, & S-10 HRSGs describing the procedures to be followed during the commissioning of the turbines in the combined-cycle configuration. The plan

shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the water injection, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S-2, S-3 and S-4) without abatement by their respective SCR Systems. The Gas Turbines (S-1, S-2, S-3 and S-4) shall be fired in combined cycle mode no sooner than fourteen days after the District receives the commissioning plan. (basis: cumulative increase)

6. During the commissioning period, the owner/operator of the Los Esteros Critical Energy Facility shall demonstrate compliance with parts 8 through 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   a. firing hours
   b. fuel flow rates
   c. stack gas nitrogen oxide emission concentrations,
   d. stack gas carbon monoxide emission concentrations
   e. stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators. The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request. (basis: cumulative increase)

7. The owner/operator shall install, calibrate and make operational the District-approved continuous monitors specified in part 6 prior to first firing of each turbine (S-1, S-2, S-3 and S-4 Gas Turbines) and HRSG (S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators). After first firing of the turbine, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to accurately measure the resulting range of CO and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval. (basis: BAAQMD 9-9-501, BACT, offsets)

8. The owner/operator shall not operate the facility such that the number of firing hours of S-1, S-2, S-3 and S-4 Gas Turbines and/or S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators without abatement by SCR or OC Systems exceed 250 hours during the commissioning period. Such operation of the S-1, S-2, S-3 and S-4 Gas Turbines without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or OC system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 250 firing hours without abatement shall expire. (basis: offsets)

9. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the S-1, S-2, S-3 and S-4 Gas Turbines and S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in part 22. (basis: offsets)

10. The owner/operator shall not operate the facility such that the pollutant mass emissions from each turbine (S-1, S-2, S-3 and S-4 Gas Turbines) and corresponding HRSG (S-7, S-8, S-9, and S-10 Heat Recovery Steam Generators) exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the S-1, S-2, S-3 and S-4 Gas Turbines.

	Without Controls		With Controls	
a. NO_x (as NO_2)	1464 lb/day	102 lb/hr	1464 lb/day	61 lb/hr
b. CO	1056 lb/day	88 lb/hr	984 lb/day	41 lb/hr
c. POC (as CH_4)	288 lb/day		288 lb/day	
d. PM_{10}	96 lb/day		96 lb/day	
e. SO_2	18.9 lb/day		18.9 lb/day	

(basis: cumulative increase)

11. Within sixty (60) days of startup, the owner/operator shall conduct a District approved source test using external continuous emission monitors to determine compliance with part 10. The source test shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Thirty (30) days before the execution of the source tests, the owner/operator shall submit to the District a detailed source test plan designed to satisfy the requirements of this part. The owner/operator shall be notified of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District comments into the test plan. The owner/operator shall notify the District within ten (10) days prior to the planned source testing date. Source test results shall be submitted to the District within 60 days of the source testing date. These results can be used to satisfy applicable source testing requirements in Part 26 below. (basis: offsets)

Conditions for Operation:

12. Consistency with Analyses: Operation of this equipment shall be conducted in accordance with all information submitted with the application (and supplements thereof) and the analyses under which this permit is issued unless otherwise noted below. (Basis: BAAQMD 2-1-403)

13. Conflicts Between Conditions: In the event that any part herein is determined to be in conflict with any other part contained herein, then, if principles of law do not provide to the contrary, the part most protective of air quality and public health and safety shall prevail to the extent feasible. (Basis: BAAQMD 1-102)

14. Reimbursement of Costs: All reasonable expenses, as set forth in the District's rules or regulations, incurred by the District for all activities that follow the issuance of this permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by the owner/operator as required by the District's rules or regulations. (Basis: BAAQMD 2-1-303)

15. Access to Records and Facilities: As to any part that requires for its effective enforcement the inspection of records or facilities by representatives of the District, the Air Resources Board (ARB), the U.S. Environmental Protection Agency (U.S. EPA), or the California Energy Commission (CEC), the owner/operator shall make such records available or provide access to such facilities upon notice from representatives of the District, ARB,

U.S. EPA, or CEC. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. (Basis: BAAQMD 1-440, 1-441)

16. Notification of Commencement of Operation: The owner/operator shall notify the District of the date of anticipated commencement of turbine operation not less than 10 days prior to such date. Temporary operations under this permit are granted consistent with the District's rules and regulations. (Basis: BAAQMD 2-1-302)

17. Operations: The owner/operator shall insure that the gas turbines, HRSGs, emissions controls, CEMS, and associated equipment are properly maintained and kept in good operating condition at all times. (Basis: BAAQMD 2-1-307)

18. Visible Emissions: The owner/operator shall insure that no air contaminant is discharged from the LECEF into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is as dark or darker than Ringelmann 1 or equivalent 20% opacity. (Basis: BAAQMD 6-301)

19. Emissions Limits: The owner/operator shall operate the facility such that none of the following limits are exceeded:

    a. The emissions of oxides of nitrogen (as NO_2) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2.0 ppmvd @ 15% O_2 (1-hour rolling average), except during periods of gas turbine startup and shutdown as defined in this permit. The NOx emission concentration shall be verified by a District-approved continuous emission monitoring system (CEMS) and during any required source test. (basis: BACT)

    b. Emissions of ammonia from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 10 ppmvd @ 15% O_2 (3-hour rolling average), except during periods of start-up or shutdown as defined in this permit. The ammonia emission concentration shall be verified by the continuous recording of the ratio of the ammonia injection rate to the NOx inlet rate into the SCR control system (molar ratio). The maximum allowable NH_3/NO_x molar ratio shall be determined during any required source test, and shall not be exceeded until reestablished through another valid source test. (basis: BAAQMD Toxics Risk Management Policy)

    c. Emissions of carbon monoxide (CO) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 9.0 ppmvd @ 15 % O_2 (3-hour rolling average), except during periods of start-up or shutdown as defined in this permit. The CO emission concentration shall be verified by a District-approved CEMS and during any required source test. (basis: BACT)

    d. Emissions of precursor organic compounds (POC) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2 ppmvd @ 15% O2 (3-hour rolling average), except during periods of gas turbine start-up or shutdown as defined in this permit. The POC emission concentration shall be verified during any required source test. (basis: BACT)

e. Emissions of particulate matter less than ten microns in diameter (PM_{10}) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 2.5 pounds per hour. The PM_{10} mass emission rate shall be verified during any required source test. (basis: BACT & cumulative increase)

f. Emissions of oxides of sulfur (as SO_2) from emission points P-1, P-2, P-3, and P-4 (combined exhaust of gas turbine/HRSG power trains S-1 & S-7, S-2 & S-8, S-3 & S-9, and S-4 & S-10, respectively) each shall not exceed 1.8 pounds per hour. The SO_2 emission rate shall be verified during any required source test. (basis: BACT & cumulative increase)

g. Compliance with the hourly NO_x emission limitations specified in part 19(a), at emission points P-1, P-2, P-3, and P-4, shall not be required during short-term excursions, limited to a cumulative total of 320 hours per rolling 12 month period for all four sources combined. Short-term excursions are defined as 15-minute periods designated by the Owner/Operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O_2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling
(2) Initiation/shutdown of combustion turbine water mist or steam injection for power augmentation
(3) Rapid combustion turbine load changes
(4) Initiation/shutdown of HRSG duct burners
(5) Provision of ancillary services and automatic generation control at the direction of the California Independent System Operator (Cal-ISO)

The maximum 1-hour average NO_x concentration for short-term excursions at emission points P-1, P-2, P-3, and P-4 each shall not exceed 5 ppmv, dry @ 15% O_2. All emissions during short-term excursions shall be included in all calculations of hourly, daily and annual mass emission rates as required by this permit.

20. Turbine Start-up: The owner/operator shall operate the gas turbines so that the duration of a startup is kept to a minimum, consistent with good engineering practice. The start-up period begins with the turbine's initial firing and continues until the unit is in compliance with all applicable emission concentration limits. For purposes of this Part, a start-up period of 240 minutes or less shall be considered kept to a minimum consistent with good engineering practice. Should it be determined that good engineering practice requires a different time period for a start-up, the owner/operator may operate the gas turbines such that startups do not exceed that time period, as approved in writing by the APCO. (Basis: BACT)

21. Turbine Shutdown: The owner/operator shall operate the gas turbines so that the duration of a shutdown is kept to a minimum, consistent with good engineering practice. Shutdown begins with the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. For purposes of this Part, a shutdown period of 30 minutes or less shall be considered kept to a minimum consistent with good engineering practice. Should it be determined that good engineering practice requires a different time period for a shutdown, the owner/operator may operate the gas turbines such that shutdowns do not exceed that time period, as approved in writing by the APCO. (Basis: BACT)

22. Mass Emission Limits: The owner/operator shall operate the LECEF so that the mass emissions from the S-1, S-2, S-3 & S-4 Gas Turbines and S-7, S-8, S-9, & S-10 HRSGs do

not exceed the daily and annual mass emission limits specified below. The owner/operator shall implement process computer data logging that includes running emission totals to demonstrate compliance with these limits so that no further calculations are required.

Mass Emission Limits (Including Gas Turbine Start-ups and Shutdowns)

Pollutant	Each Turbine/HRSG Power Train (lb/day)	All 4 Turbine/HRSG Power Trains (lb/day)	All 4 Turbine/HRSG Power Trains (ton/yr)
NOx (as NO_2)	252.4	1,009.6	99
POC	80.2	320.8	28.3
CO	417.2	1,668.8	98.5
SOx (as SO_2)	41.6	166.4	8.4
PM_{10}	60	240	43.8
NH_3	198	792	118

The daily mass limits are based upon calendar day per the definitions section of the permit conditions. The annual mass limit is based upon a rolling 8,760-hour period ending on the last hour. Compliance shall be based on calendar average one-hour readings through the use of process monitors (e.g., fuel use meters), CEMS, source test results, and the monitoring, recordkeeping and reporting conditions of this permit. If any part of the CEM involved in the mass emission calculations is inoperative for more then three consecutive hours of plant operation, the mass data for the period of inoperation shall be calculated using a District-approved alternate calculation method. (Basis: cumulative increase, recordkeeping)

23. Sulfuric Acid Mist Limit: The owner/operator shall operate the LECEF so that the sulfuric acid mist emissions (SAM) from S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10 combined do not exceed 7 tons totaled over any consecutive four quarters. (Basis: PSD)

24. Operational Limits: In order to comply with the mass emission limits of this rule, the owner/operator shall operate the gas turbines and HRSGs so that they comply with the following operational limits:

a. Heat input limits (Higher Heating Value):

	Each Gas Turbine w/o Duct Burner	Each Gas Turbine w/Duct Burner
Hourly:	500 MM BTU/hr	639 MM BTU/hr
Daily:	12,000 MM BTU/day	15,336 MM BTU/day
Four Turbine/HRSG Power Trains combined:		18,215,000 MM BTU/year

b. Only PUC-Quality natural gas (General Order 58-a) shall be used to fire the gas turbines and HRSGs. The total sulfur content of the natural gas shall not exceed 1.0 gr/100 scf.

c. The owner/operator of the gas turbines and HRSGs shall demonstrate compliance with the daily and annual NOx and CO emission limits listed in part 22 by maintaining running mass emission totals based on CEM data. (Basis: Cumulative increase)

25. Monitoring Requirements: The owner/operator shall ensure that each gas turbine/HRSG power train complies with the following monitoring requirements:

a. The gas turbine/HRSG exhaust stack shall be equipped with permanent fixtures to enable the collection of stack gas samples consistent with EPA test methods.

b. The ammonia injection system shall be equipped with an operational ammonia flowmeter and injection pressure indicator accurate to plus or minus five percent at full scale and shall be calibrated at least once every twelve months.

c. The gas turbine/HRSG exhaust stacks shall be equipped with continuously recording emissions monitor(s) for NOx, CO and O_2. Continuous emissions monitors shall comply with the requirements of 40 CFR Part 60, Appendices B and F, and 40 CFR Part 75, and shall be capable of monitoring concentrations and mass emissions during normal operating conditions and during gas turbine startups and shutdowns.

d. The fuel heat input rate shall be continuously recorded using District-approved fuel flow meters along with quarterly fuel compositional analyses for the fuel's higher heating value (wet basis).

26. Source Testing/RATA: Within ninety (90) days of the startup of the gas turbines and HRSGs, and at a minimum on an annual basis thereafter, the owner/operator shall perform a relative accuracy test audit (RATA) on the CEMS in accordance with 40 CFR Part 60 Appendix B Performance Specifications and a source test shall be performed. Additional source testing may be required at the discretion of the District to address or ascertain compliance with the requirements of this permit. The written test results of the source tests shall be provided to the District within thirty days after testing. A complete test protocol shall be submitted to the District no later than 30 days prior to testing, and notification to the District at least ten days prior to the actual date of testing shall be provided so that a District observer may be present. The source test protocol shall comply with the following: measurements of NOx, CO, POC, and stack gas oxygen content shall be conducted in accordance with ARB Test Method 100; measurements of PM_{10} shall be conducted in accordance with ARB Test Method 5; and measurements of ammonia shall be conducted in accordance with Bay Area Air Quality Management District test method ST-1B. Alternative test methods, and source testing scope, may also be used to address the source testing requirements of the permit if approved in advance by the District. The initial and annual source tests shall include those parameters specified in the approved test protocol, and shall at a minimum include the following:

a. NOx– ppmvd at 15% O2 and lb/MM BTU (as NO2)
b. Ammonia – ppmvd at 15% O2 (Exhaust)
c. CO – ppmvd at 15% O2 and lb/MM BTU (Exhaust)
d. POC – ppmvd at 15% O2 and lb/MM BTU (Exhaust)
e. PM_{10} – lb/hr (Exhaust)
f. SOx – lb/hr (Exhaust)
g. Natural gas consumption, fuel High Heating Value (HHV), and total fuel sulfur content
h. Turbine load in megawatts
i. Stack gas flow rate (DSCFM) calculated according to procedures in U.S. EPA Method 19
j. Exhaust gas temperature (°F)
k. Ammonia injection rate (lb/hr or moles/hr)
l. Water injection rate for each turbine at S-1, S-2, S-3, & S-4
(Basis: source test requirements & monitoring)

27. Within 60 days of start-up of the LECEF in combined-cycle configuration and on a semi-annual basis thereafter, the owner/operator shall conduct a District approved source test on exhaust points P-1, P-2, P-3, and P-4 while each Gas Turbine/HRSG power train is operating at

maximum load to demonstrate compliance with the SAM emission limit specified in part 23. The owner/operator shall test for (as a minimum) SO_2, SO_3 and SAM. After acquiring one year of source test data on these units, the owner/operator may petition the District to switch to annual source testing if test variability is acceptably low as determined by the District. (Basis: PSD Avoidance, SAM Periodic Monitoring)

28. The owner/operator shall prepare a written quality assurance program must be established in accordance with 40 CFR Part 75, Appendix B and 40 CFR Part 60 Appendix F. (Basis: continuous emission monitoring)

29. The owner/operator shall comply with the applicable requirements of 40 CFR Part 60 Subpart GG, excluding sections 60.334(a) and 60.334(c)(1). The sulfur content of the natural gas fuel shall be monitored in accordance with the following custom schedule approved by the USEPA on August 14, 1987:
    a. The sulfur content shall be measured twice per month for the first six months of operation.
    b. If the results of the testing required by Part 29a are below 0.2% sulfur by weight, the sulfur content shall be measured quarterly for the next year of operation.
    c. If the results of the testing required by Part 29b are below 0.2% sulfur by weight, the sulfur shall be measured semi-annually for the remainder of the permit term.
    d. The nitrogen content of the fuel gas shall not be monitored in accordance with the custom schedule. (Basis: NSPS)

30. The owner/operator shall notify the District of any breakdown condition consistent with the District's breakdown regulations. (Basis: Regulation 1-208)

31. The owner/operator shall notify the District in writing in a timeframe consistent with the District's breakdown regulations following the correction of any breakdown condition. The breakdown condition shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the actions taken to restore normal operations. (Basis: Regulation 1-208)

32. <u>Recordkeeping</u>: The owner/operator shall maintain the following records. The format of the records is subject to District review and approval:

    a. hourly, daily, quarterly and annual quantity of fuel used and corresponding heat input rates
    b. the date and time of each occurrence, duration, and type of any startup, shutdown, or malfunction along with the resulting mass emissions during such time period
    c. emission measurements from all source testing, RATAs and fuel analyses
    d. daily, quarterly and annual hours of operation
    e. hourly records of NOx and CO emission concentrations and hourly ammonia injection rates and ammonia/NOx ratio
    f. for the continuous emissions monitoring system; performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor
    (Basis: record keeping)

33. The owner/operator shall maintain all records required by this permit for a minimum period of five years from the date of entry and shall make such records readily available for District inspection upon request. (Basis: record keeping)

34. Reporting: The owner/operator shall submit to the District a written report for each calendar quarter, within 30 days of the end of the quarter, which shall include all of the following items:

    a. Daily and quarterly fuel use and corresponding heat input rates
    b. Daily and quarterly mass emission rates for all criteria pollutants during normal operations and during other periods (startup/shutdown, breakdowns)
    c. Time intervals, date, and magnitude of excess emissions
    d. Nature and cause of the excess emission, and corrective actions taken
    e. Time and date of each period during which the CEM was inoperative, including zero and span checks, and the nature of system repairs and adjustments
    f. A negative declaration when no excess emissions occurred
    g. Results of quarterly fuel analyses for HHV and total sulfur content.
    (Basis: recordkeeping & reporting)

35. Emission Offsets: The owner/operator shall provide 7.5 tons of valid POC emission reduction credits and 27.945 tons of valid NOx emission reduction credits prior to the issuance of the Authority to Construct. The owner/operator shall deliver the ERC certificates to the District Engineering Division at least ten days prior to the issuance of the authority to construct. (Basis: Offsets)

36. District Operating Permit: The owner/operator shall apply for and obtain all required operating permits from the District in accordance with the requirements of the District's rules and regulations. (Basis: Regulations 2-2 & 2-6)

37. Title IV and Title V Permits: The owner/operator must deliver applications for the Title IV and Title V permits to the District prior to first-fire of the turbines. The owner/operator must cause the acid rain monitors (Title IV) to be certified within 90 days of first-fire. (Basis: BAAQMD Regulation 2, Rules 6 & 7)

38. Deleted June 22, 2004.

39. The owner/operator shall insure that the S-5 Fire Pump Diesel Engine is fired exclusively on diesel fuel with a maximum sulfur content of 0.05% by weight. (Basis: TRMP, cumulative increase)

40. The owner/operator shall operate the S-5 Fire Pump Diesel Engine for no more than 100 hours per year or 45 minutes per day for the purpose of reliability testing and non-emergency operation. (Basis: cumulative increase, Regulation 9-8-231 & 9-8-330)

41. The owner/operator shall equip the S-5 Fire Pump Diesel Engine with a non-resettable totalizing counter that records hours of operation. (Basis: BACT)

42. The owner/operator shall maintain the following monthly records in a District-approved log for at least 5 years and shall make such records and logs available to the District upon request:
    a. Total number of hours of operation for S-5
    b. Fuel usage at S-5
    (Basis: BACT)

43. The owner/operator shall operate the facility such that maximum calculated annual toxic air contaminant emissions (pursuant to part 44) from the gas turbines and HRSGs combined (S-1, S-2, S-3, S-4, S-7, S-8, S-9, and S-10) do not exceed the following limits:

6490 pounds of formaldehyde per year
3000 pounds of acetaldehyde per year
3.2 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year
65.3 pounds of acrolein per year

unless the following requirement is satisfied:
The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Basis: TRMP)

44. To demonstrate compliance with Part 43, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions for the compounds specified in part 43 using the maximum heat input of 18,215,000 MM BTU/year and the highest emission factor (pound of pollutant per MM BTU) determined by any source test of the S-1, S-2, S-3 & S-4 Gas Turbines and S-7, S-8, S-9, and S-10 HRSGs. If this calculation method results in an unrealistic mass emission rate the applicant may use an alternate calculation, subject to District approval. (Basis: TRMP)

45. Within 60 days of start-up of the Los Esteros Critical Energy Facility and on a biennial (once every two years) thereafter, the owner/operator shall conduct a District-approved source test at exhaust point P-1, P-2, P-3, or P-4 while the Gas Turbines are at maximum allowable operating rates to demonstrate compliance with Part 43. If three consecutive biennial source tests demonstrate that the annual emission rates for any of the compounds listed above calculated pursuant to part 43 are less than the BAAQMD Toxic Risk Management Policy trigger levels shown below, then the owner/operator may discontinue future testing for that pollutant.

Formaldehyde	<	132 lb/yr
Acetaldehyde	<	288 lb/yr
Specified PAHs	<	0.18 lb/yr
Acrolein	<	15.6 lb/yr

(Basis: BAAQMD 2-1-316, TRMP)

46. The owner/operator shall properly install and maintain the cooling towers to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 10,000 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (Basis: BACT, cumulative increase)

47. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the combined-cycle Los Esteros Critical Energy Facility, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in accordance with the manufacturer's design and specifications. Within 60 days of the initial

operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in part 46. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in part 46. (Basis: BACT, cumulative increase)

Summary and Determination

The proposed combined-cycle configuration of the Los Esteros Critical Energy Facility complies with all applicable federal, state and District rules and regulations. Therefore, the District recommends issuance of the Final Determination of Compliance for the combined-cycle conversion of the Los Esteros Critical Energy Facility that is comprised of the following permitted pieces of equipment:

S-1 Combustion Gas Turbine #1 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-2 Combustion Gas Turbine #2 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #3 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System.

S-4 Combustion Gas Turbine #4 with Water Injection, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM BTU/hr (HHV) maximum heat input rating; abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-5 Fire Pump Diesel Engine, John Deere Model JDFP-06WR, 290 bhp, 13.5 gal/hr

S-7 Heat Recovery Steam Generator #1, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM BTU/hr abated by A-7 Oxidation Catalyst and A-8 Selective Catalytic Reduction System

S-11 Six-Cell Cooling Tower, 73,000 gallons per minute

Pursuant to District Regulation 2-3-404, the revised Preliminary Determination of Compliance (PDOC) has satisfied the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. A notice inviting written public comment on the proposed modifications to the LECEF was published in the San Jose Mercury News on March 23, 2005. Written comments on the revised PDOC were submitted by the CEC, USEPA, and Michael Boyd, a private citizen. All comments received during the 30-day public comment period will be considered and responses to those comments will be prepared. Where appropriate, this Final Determination of Compliance (FDOC) includes changes in response to those comments.

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Appendix A

Control Equipment Cost Summary