Request for Renewal

Authority to Construct
for the
Los Esteros Critical Energy Facility
Combined-Cycle Conversion (Phase 2)

Plant Number 13289

In Conjunction With

California Energy Commission
License Amendment
Proceeding 03-AFC-2C

Bay Area Air Quality Management District
Authority to Construct Number 8859

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APPLICTION FOR AUTHORITY TO CONSTRUCT RENEWAL

LOS ESTEROS CRITICAL ENERGY FACILITY

Application Number 8859

Plant Number 13289

Table of Contents

I. Introduction and Summary 3

II. Project Description 4

III. Best Available Control Technology (BACT) Review 8

III.A. BACT for Gas Turbine and HRSG Duct Burners 8

III.A.1. Nitrogen Oxides (NOx) 9

III.A.2. Carbon Monoxide (CO) 14

III.A.3. Sulfur Dioxide (SO_2) 19

III.A.4. Particulate Matter (PM) 20

III.A.5. Precursor Organic Compounds (POC) 22

III.A.6. Startup and Shutdown Emissions 26

III.A.6.i. – Turbine Startups 26

III.A.6.ii. – Turbine Shutdowns 29

III.B. BACT for Six-Cell Cooling Tower 30

III.C. BACT for Commissioning Period 31

IV. Emissions Calculations and Offsets Review 33

V. Permit Conditions For ATC Renewal 35

VI. Summary and Determination 50

Appendices

Appendix A: Emissions Calculations A-1

Tables

Table 1: Existing Emission Limits for the LECEF Phase I Simple-Cycle Plant 5

Table 2: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC in 2007 5

Table 3: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC Renewal in 2010 6

Table 4: Comparison of Maximum Annual Facility Emission Limits (tons/yr) 6

Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers 15

Table 6: Recent BACT NO_X and POC Permit Limits for Large Combined-Cycle Turbines 22

Table 7: City of San Jose Annual Average Recycled Water TDS Levels (ppmw (mg/l)) 31

Table 8: Emissions Offsets Required (tons/yr) 33

I. Introduction and Summary

Los Esteros Critical Energy Facility, LLC has requested a renewal of the Authority to Construct (ATC) for Phase II of the Los Esteros Critical Energy Facility (LECEF2). The LECEF Phase II project is a conversion of the facility from a simple-cycle facility to a more efficient combined-cycle operation. The California Energy Commission (CEC) licensed the Phase II project on October 11, 2006, and the District subsequently issued the Authority to Construct for the Phase II conversion project on August 22, 2007,[1] with a two-year term. The two-tear term has expired, and so the applicant is now seeking to have the Authority to Construct renewed for another two years.

This application is being processed under the auspices of the CEC power plant licensing process, which supersedes District permitting authority under the Warren-Alquist State Energy Resources Conservation and Development Act (Warren-Alquist Act).[2] The applicant filed a petition for amendment of its CEC license on October 30, 2009, which included a request to revise certain Conditions of Certification so they meet the requirements for renewal of the Authority to Construct. The CEC will be making its determination on the applicant's petition under its Warren-Alquist licensing authority, and it has requested the District's input on current air quality requirements. This analysis has been prepared in response to that request. Upon determination by the CEC that the project meets current air quality requirements and amendment of any license conditions that need to be brought up to date, the District will then be able to renew the Authority to Construct consistent with the CEC's license.

Renewal of the Authority to Construct is subject to District Regulation 2-1-407.1, which provides that an Authority to Construct may be renewed for an additional two years upon a showing that the project will meet current Best Available Control Technology (BACT) and offset requirements as defined in District Regulations 2-2-301, 302, and 303. This document provides the District's evaluation of the project's compliance with the current BACT and offset requirements in accordance with Regulation 2-1-407.1 as a prerequisite for renewal of the Authority to Construct. The District will submit this analysis to the CEC for use in its license amendment process to help the CEC with its determination as to whether the facility meets current BACT and offset requirements.

The District's review of current BACT and offsets as described herein has found that the majority of the BACT and offset conditions established for the CEC license and Authority to Construct meet current standards, with several exceptions that will need to be modified. Specifically, the District has found that under current BACT standards the limit on carbon monoxide emissions of

[1] BAAQMD Application No. 8859.

[2] *See* Public Resources Code section 25500 ("The issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency, or federal agency to the extent permitted by federal law, for such use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency, or federal agency to the extent permitted by federal law.)"

9.0 ppm (3-hour average) should be lowered to 2.0 ppm (1-hour average), and the limit on precursor organic compounds (POC) of 2.0 ppm (3-hour average) should be lowered to 1.0 ppm (1-hour average). In addition, the District found that the existing limits on the duration of turbine startups should be reduced to meet current BACT standards, and should also have numerical emissions limits added for startup and shutdown events. The District has also found that the limit on total dissolved solids (TDS) content in the cooling water can feasibly be lowered to 6,000 ppm. At this level, particulate emissions from the cooling system will be reduced to a level where the BACT requirement is not triggered, meaning that the cooling system will be consistent with current BACT requirements. The District's BACT review is set forth in detail in Section III.

As noted above, under the Warren-Alquist Act any renewal of the Authority to Construct must be consistent with the license issued for the Phase II conversion project by the CEC. As a result, the District cannot issue a renewed ATC with conditions that are inconsistent with the conditions of the CEC's license. Upon incorporation of current BACT and offset conditions into the CEC license for the facility, the District can renew the ATC with these revised conditions.

ATC renewals are not subject to the public notice and comment provisions applicable to initial permit issuance under District Regulations 2-2-405 through 2-2-407. The CEC will provide an opportunity for the public to comment on the conditions of the renewed ATC during the CEC's license amendment process, however. If the CEC amends its license for the LECEF, the District will issue the renewed ATC consistent with the CEC license.

II. Project Description

The existing LECEF facility is a simple-cycle "peaker" power plant that uses four natural gas fired LM6000PC combustion turbines to generate a nominal 190 megawatts (MW) of electricity. The current facility was licensed by the CEC in July of 2002, and it became fully functional in March of 2003.[3] The current simple-cycle facility was licensed as Phase I of a two-phase project, with Phase II to consist of a conversion to a more efficient combined-cycle operation. In a combined-cycle operation, the waste heat in the turbine exhaust is recovered to make steam to turn a steam turbine and generate additional electric power, which increases the plant's overall efficiency.

The LECEF Phase II conversion project will add four heat recovery steam generators (HRSGs) to make steam from the turbine exhaust, a steam turbine generator to generate electricity from the steam, and a six-cell cooling tower. Each HRSG will be equipped with a duct burner to provide a maximum 139 MMBtu/hr of supplemental heat. This is a "4x1" configuration in which the steam output from the four heat recovery steam generators will be used to feed one steam turbine generator. The modified LECEF2 facility will have a nominal output of 320 MW as a result of the addition of the nominal 130 MW steam turbine generator. In addition, the maximum rated heat input of each gas turbine will increase from 472.6 MMBtu/hr (HHV) to 500 MMBtu/hr (HHV).

[3] *See* Commission Decision, Los Esteros Critical Energy Facility II, Phase 2, Application for Certification (03-AFC-2), October 2006 ("LECEF Phase 2 Certification"), at 1.

Exhaust concentrations of NOx, CO, and POC will be reduced substantially when the LECEF is converted to a combined-cycle power plant.[4] To achieve these reductions, the existing high-temperature selective catalytic reduction (SCR) and oxidation catalysts will be replaced with new low-temperature SCR systems and new oxidation catalysts.[5]

The CEC issued its license for the Phase II combined-cycle conversion project in October of 2006,[6] and the District issued its Authority to Construct for the Phase II project in August of 2007. The applicant submitted its application for renewal of the ATC on June 5, 2009, which was prior to the expiration of the initial ATC for the Phase II project as required by Regulation 2-1-407.

The emission limits for the existing Phase I simple-cycle plant are presented in Table 1 below.[7]

Table 1: Existing Emission Limits for the LECEF Phase I Simple-Cycle Plant

Pollutant	NO_x	POC	PM_{10}	CO	SO_2
Emission Limit	5.0 ppmvd 3-hr avg.	2.0 ppmvd 3-hr avg.	2.5 lb/hr	4.0 ppmvd 3-hr avg.	0.33 lb/hr[a]

[a] calculated based on an annual average sulfur content of 0.25 gr/100 dscf in natural gas fuel

The emission limits for the Phase II combined-cycle plant as approved in 2007 are presented in Table 2 below.[8]

Table 2: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC in 2007

Pollutant	NO_x	POC	PM_{10}	CO	SO_2
Emission Limit	2.0 ppmvd[a] 1-hr avg.	2.0 ppmvd 3-hr avg.	2.5 lb/hr	9.0 ppmvd 3-hr avg.	1.8 lb/hr[b]

[a] With short-term excursion language for transient load conditions that allows up to 5 ppm NO_x concentration.
[b] calculated based on maximum sulfur content of 1.0 gr/100 dscf in natural gas fuel

[4] *See* Tables 1, 2, and 3 for existing simple-cycle and proposed combined-cycle emission limits.

[5] High-temperature SCR units are required for the simple-cycle turbine due to high exhaust temperatures. The combined-cycle plant will recover heat from the turbine exhaust, lowering its temperature, enabling low-temperature SCR systems to be used.

[6] *See* LECEF Phase 2 Certification at 34.

[7] The detailed calculations are found in Final Determination of Compliance, Application No. 3213.

[8] The detailed calculations are found in the Final Determination of Compliance for the Los Esteros Critical Energy Facility, Application No. 8859, June 28, 2005.

The revised emission limits for the Phase II ATC renewal based on current BACT as discussed in this evaluation are presented in Table 3 below:

Table 3: Emission Limits for the LECEF Phase II Combined Cycle Plant Conversion Project ATC Renewal in 2010					
Pollutant	NO_x	POC	PM_{10}	CO	SO_2
Emission Limit	2.0 ppmvd[a] -hr avg.	1.0 ppmvd 1-hr avg.	technology[b]	2.0 ppmvd1-hr avg.	technology[b]

[a] With no provision for transient load excursions

[b] The District has established BACT for PM_{10} and SO_2 as a control technology and not as a numerical emissions limit. This determination is discussed in Sections III.A.3. and III.A.4. below. There will be no difference in the amount of PM_{10} and SO_2 that will be emitted.

A comparison of annual emissions limits for the facility in the Phase I ATC, the initial Phase II ATC, and the Phase II ATC renewal is presented in Table 4 below:

Table 4: Comparison of Maximum Annual Facility Emission Limits (tons/yr)					
	NO_x	**POC**	**PM_{10}**	**CO**	**SO_2**
Permit Limits for the Phase I Simple-Cycle Plant as approved in 2002	74.9	21.0	43.8	72.9	5.8
Permit Limits for the Phase II ATC issued in 2007	99.2	28.3	53.3	98.6	8.4
Permit Limits for the Phase II ATC Renewal Based on Current BACT	95.21	12.31	44.24	53.44	6.45

In addition, Calpine has requested that its ammonia slip limit be reduced from 10 ppm to 5 ppm as part of the ATC renewal for this project. The conversion to a combined cycle facility will allow the use of a low-temperature SCR system that will have a higher NOx abatement efficiency than the high-temperature SCR system that it will replace. The higher efficiency of the low-temperature SCR allows the plant to reduce the injection of excess ammonia to ensure proper NOx and ammonia mixing and distribution across the catalyst.

<u>Permitted Source Descriptions</u>:

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

S-1 Combustion Gas Turbine #1 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-9 Oxidation Catalyst and A-10 Selective Catalytic Reduction System

S-2 Combustion Gas Turbine #2 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-11 Oxidation Catalyst and A-12 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #3 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-13 Oxidation Catalyst and A-14 Selective Catalytic Reduction System

S-4 Combustion Gas Turbine #4 with Water Injection and high efficiency inlet air filter, General Electric LM6000PC Sprint, natural gas fired, 49.4 MW, 500 MM Btu/hr (HHV) maximum heat input rating; abated by A-15 Oxidation Catalyst and A-16 Selective Catalytic Reduction System

S-5 Fire Pump Diesel Engine, Clarke 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 (HHV) abated by A-9 Oxidation Catalyst, and A-10 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #2, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-11 Oxidation Catalyst, and A-12 Selective Catalytic Reduction System

S-9 Heat Recovery Steam Generator #3, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-13 Oxidation Catalyst, and A-14 Selective Catalytic Reduction System

S-10 Heat Recovery Steam Generator #4, equipped with low-NOx Duct Burners, 139 MM Btu/hr (HHV) abated by A-15 Oxidation Catalyst, and A-16 Selective Catalytic Reduction System

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

The facility also has an existing one-cell cooling tower that is exempt from District permitting requirements.

III. Best Available Control Technology (BACT) Review

The first requirement for renewal of an Authority to Construct under District Regulation 2-1-407.1.2 is that the facility must meet current Best Available Control Technology (BACT) requirements under District Regulation 2-2-301. District Regulation 2-2-301 requires that the LECEF Phase II project use the Best Available Control Technology to control NO_x, CO, POC, PM_{10}, and SO_x emissions because it will have the potential to emit over 10 pounds per day of each of those pollutants. 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 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 it must be commercially available, 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/TBACT Workbook.

The District has reviewed the Phase II conversion project under Regulation 2-1-407.1.2 to determine whether it meets current BACT standards. The results of the District's BACT review are described in the following subsections.

III.A. BACT for Gas Turbine and HRSG Duct Burners

The following section provides the District's BACT review by pollutant for the gas turbines and HRSG duct burners. Because each gas turbine and its associated HRSG/duct burners will exhaust through a common stack and be subject to common emission limitations, the BACT review is made for each Gas Turbine/HRSG power train as a combined unit.

III.A.1. Nitrogen Oxides (NOx)

The simple-cycle LECEF operation 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 startups and shutdowns. The Phase II Authority to Construct (ATC) provides that when the facility is converted to combined-cycle operation, the NOx limit will be reduced to 2.0 ppmv @ 15% O_2, dry averaged over one hour with limited allowable excursions (not to exceed 5 ppmv) due to transient conditions such as rapid load changes. The District has reviewed this BACT determination and found that the 2.0 ppm limit meets current BACT, but has concluded that the excursion language can no longer be justified as BACT. The District has therefore determined that current BACT for NOx is an emission limit of 2.0 ppm averaged over one hour at all times (excluding startups and shutdowns).

The District reviewed its BACT guideline for large combined-cycle gas turbines, Guideline 89.1.6., and found that it has not been revised since the initial Phase II ATC was issued. The District also reviewed permit limits from permits that have been issued for similar facilities recently, and did not find any permit limits more stringent than the 2.0 ppm (1-hour average) in any Authority to Construct.[9] The District also reviewed the available technologies for controlling NOx from combined-cycle gas turbines, and has not found any additional technologies that could be used here to achieve a BACT limit below 2.0 ppm. The facility will use water injection in the combustion turbines to help minimize the formation of NOx during combustion, and a Selective Catalytic Reduction (SCR) system to control NOx in the exhaust stream. The District has not found any more effective control devices or techniques that could appropriately be required as BACT for this project.

- ***Consideration of NOx Control Technologies:***

The District considered two additional technologies for controlling NOx emissions in its BACT review. The first is a recent development in dry low-NOx combustor technology that can achieve 15 ppm NOx emissions in the turbine exhaust (before abatement by any add-on control device). This 15 ppm emissions rate would be an improvement compared to the LM6000 PC turbines that Calpine is currently using at the facility, which use water injection for NOx control are rated at 25 ppm NOx emissions in the turbine exhaust. Calpine used the LM6000 PC turbines because they equaled the best NOx emissions performance that could be achieved at the time,[10] and because

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[9] One facility that the District reviewed, the IDC Bellingham facility in Massachusetts, has a two-tiered NOx emissions limit that requires the facility to maintain emissions below 1.5 ppm during normal operations but allows emissions of up to 2.0 ppm as absolute not-to-exceed limit. This two-tiered limit recognizes that emissions can be highly variable depending on operating circumstances, and will have relatively lower emissions at some times and relatively higher emissions at other times. The proposed LECEF2 is expected to exhibit the same type of variation in emissions under the various operating scenarios it will face, and will have emissions as high as 2.0 under some circumstances. The IDC Bellingham permit therefore supports the District's conclusion that 2.0 ppm is current BACT for NOx.

[10] *See* GE Energy Estimated Engine Performance for LM6000 PD-Sprint and LM6000 PC-Sprint reports dated April 30, 2004.

turbines using water injection are capable of producing a higher power output.[11] Because water injection was equivalent to dry low-NOx combustor technology at the time in terms of NOx reduction efficiency, either of them would have been consistent with the BACT requirement.

New dry low-NOx combustor technology has recently become available, however, and so the District evaluated whether Calpine should be required to retrofit the facility with this technology as part of the LECEF Phase II project. But retrofitting an existing facility with completely new turbines is not normally required for this type of project and so it cannot be "achieved in practice" for purposes of the BACT requirement. Similarly, the high costs involved would render it not sufficiently cost-effective to require as BACT. The cost of the conversion would range between $11.25 and $11.75 million per turbine.[12] There would most likely be some additional NOx benefit to be gained from this additional cost, although it is not clear that any additional benefit would be significant and there is no guarantee that new turbines would allow the facility to consistently achieve NOx emissions below 2.0 ppm. The District conservatively assumed for purposes of its analysis that dry low-NOx combustors could allow the facility to achieve a reduced NOx emissions rate of 1.5 ppm. At this reduced rate, an additional 16.1 tons of NOx per year could be avoided. The cost to achieve a reduction in annual emissions of 16.1 tons of NOx would be an annualized cost of $8.5 million for an incremental cost-effectiveness of about $530,000 per ton.[13] Achieving emissions reductions at this cost would therefore not be sufficiently cost-effective to require as BACT.[14] Note that this analysis does not consider the ancillary costs and environmental consequences related to junking the existing LECEF's equipment in favor of the new equipment.

The second technology the District considered is an add-on control technology known as EMx™. EMx™ (formerly SCONOx™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NO_x, as well as CO, VOC and optionally SO_x emissions. EMx could potentially be an improvement over SCR as an add-on control device for achieving NOx reductions because it does not use ammonia. Ammonia has the potential, under certain atmospheric conditions, to react with nitric acid in the atmosphere to form ammonium nitrate, which can be a form of fine particulate matter ($PM_{2.5}$). The atmospheric chemistry regarding the extent to which this process actually happens under real-world conditions has historically not been well understood, and the District's scientific understanding has been until recently that there was insufficient nitric acid in the atmosphere to make secondary $PM_{2.5}$ formation a significant concern. As a result, the District has not historically regulated ammonia as a $PM_{2.5}$ precursor, and has not found that EMx's lack of ammonia slip emissions would provide any significant benefit over SCR.

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[11] *Id.*

[12] *See* email from Michael T. McCarrick (GE Power & Water, Repowering) to Larry Salguero (Calpine Corp., Engineer III, Transaction Support) Subject: LM6PC to PF Conversion, October 1, 2010 (quoting an original equipment manufacturer (OEM) Cost of $9.5 to 10 MM; Field Service and Technical Support costs of $750,000 and Labor and Materials costs of $1,000,000, for a total of $11.25 MM to 11.75 MM per turbine).

[13] *See* Spreadsheet, NOx incremental 2 to 1.5 PF Turbines, prepared by Barbara McBride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.

[14] The District's guideline for cost-effectiveness for NOx emission reductions is $17,500 per ton. See BAAQMD BACT Policy and Implementation at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm. The cost-effectiveness of requiring LM 6000 PF turbines here would be well over this threshold.

The District has recently been reevaluating whether ammonia is in fact a significant contributor to secondary $PM_{2.5}$. The focus of the District's further evaluation has been a computer modeling exercise designed to predict what $PM_{2.5}$ levels will be around the Bay Area, given certain assumptions about emissions of $PM_{2.5}$ and its precursors, about regional atmospheric chemistry, and about prevailing meteorological conditions.[15] The results of this study, while still preliminary, confirm that the predominant limiting factor in the formation of secondary particulate matter is the availability of nitric acid, not ammonia. However, the study suggests that the amount of available nitric acid is not uniform and varies in different locations around the Bay Area, and that in some locations there is available nitric acid to react with ammonia. The District's model thus predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes in ambient $PM_{2.5}$ levels of between 0% and 4%, depending on the availability of nitric acid. While this analysis is still preliminary, it suggests that that ammonia restrictions might play a role in a regional strategy to reduce $PM_{2.5}$.[16] The District is therefore evaluating whether it should impose regulations on ammonia emissions as a $PM_{2.5}$ precursor, and is also taking a harder look at whether it should require EMx as a BACT control technology for NOx reductions instead of SCR.

The District therefore evaluated whether EMx would be an improvement over SCR, which has been proven to be able to keep NOx emissions below 2.0 ppm for a facility like this one. EMx has only been used at one facility with a gas turbine of a similar size to this facility, at Redding Power Plant Unit No. 5, a 45-MW combined-cycle facility in Shasta County, CA. The Shasta County Air Quality Management District evaluated EMx™ at that facility under a demonstration NO_x limit of 2.0 ppm. After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EMx™, and concluded that "Redding Power is not able to reliably and continuously operate while maintaining the NO_x demonstration limit of 2.0 ppmvd @ 15% O_2."[17] Although the manufacturer maintains that such problems have been overcome, concerns remain about how consistently the technology would be able to perform. Recent communications with the Shasta County Air District confirm that the earlier conclusions about the achievability of a lower limit remain valid.[18] In addition, monthly reports of Continuous Emissions Monitoring System (CEMS) data submitted by Redding Power Plant to Shasta County Air District during the past three calendar years indicate that emissions have often been substantially higher.[19] Because EMx cannot achieve the high level of emissions

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[15] *See* BAAQMD, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Oct. 1, 2009), at p. 8 ($PM_{2.5}$ Modeling Report). (available at: www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Research%20and%20Modeling/PM-data-analysis- and-modeling-report.ashx)

[16] *Id* at pp. E-3 – E-4.

[17] Letter from R. Bell, Air Quality District Manager, Shasta County Air Quality Management District, to R. Bennett, Safety & Environmental Coordinator, Redding Electric Utility, June 23, 2005.

[18] Telephone conversation between W. Lee and R. Bell, October 25, 2010. Mr. Bell confirmed that unit No. 5 demonstrated that it is not capable of meeting a NOx limit of 2 ppm (1-hr average) consistently. Unit #5 is currently required to meet a NOx limit of 2.5 ppm (rolling 1-hr average).

[19] *See* Summary of REU-Unit 5 Operating and NOx Data.

performance that SCR is capable of, the District is requiring SCR to be used instead of EMx as the BACT add-on control technology for NOx.

- ***Consideration of NOx Emissions Limit Below 2.0 ppm:***

The District also considered whether it would be feasible to implement a NO_x permit limit below 2.0 ppm. Consistent compliance with a limit below 2.0 ppm has never been demonstrated in practice, and the equipment vendors that the District contacted regarding this issue stated that they would not be able to guarantee that a lower limit could be achieved.[20] The District nevertheless considered whether it would be technologically feasible to do so. The District has concluded that imposing a NOx emissions limit below 2.0 ppm cannot be justified as BACT at this time.

Additional NOx reductions could potentially be achieved by increasing the amount of catalyst or size of the catalyst bed in the SCR system. It would be difficult to achieve any substantial additional reductions, however, because at the very low NOx levels that are currently being achieved by SCR additional efforts produce diminishing returns. SCR performance for NO_x control is highly dependent on the NO_x-to-ammonia reaction stoichiometry. At stoichiometric conditions, there would be just enough ammonia to react with the NO_x with no additional ammonia slip exhausted out the stack. It becomes highly challenging to ensure a uniform distribution of ammonia to NO_x over the entire gas turbine operating range when NOx concentrations are very low. Alternatively, some vendors have considered staging two separate ammonia injection grids and catalyst beds in series in order to achieve an optimal distribution of ammonia to NO_x that might maintain emissions at less than 2.0 ppm NO_x over the entire gas turbine operating range. But this approach has its own drawbacks, such as increasing the backpressure on the turbine exhaust and decreasing the efficiency of the turbine resulting in higher emissions per megawatt of power generated. Moreover, no installation using a staged series of ammonia injection grids has been demonstrated in practice. Additionally, temperature variations across the catalyst bed also impact SCR performance. At progressively lower NOx concentrations, these variations have an increasingly significant impact on maintaining stoichiometric conditions. For all of these reasons, it becomes increasingly difficult to gain additional NOx reductions as concentrations are driven to extremely low levels simply by increasing the amount of catalyst or the size of the catalyst bed. Increasing the amount of catalyst or size of catalyst bed theoretically can provide for more NOx reduction, but for a number of reasons simply adding more catalyst reaches a point of diminishing returns as NOx levels approach zero.[21]

In addition, achieving lower NOx emissions levels would have other potential offsetting impacts. Ensuring emissions consistently remain below 2.0 ppm could potentially cause a significant increase in ammonia slip and require a higher ammonia slip permit limit. Implementing a NO_x

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[20] *See, e.g., See* email from Shaun P. Hennessey (Manager of Thermal Design, Nooter/Eriksen, Inc.) to Paul C. Berthiaume P.E. (Chief Mechanical Engineer, Calpine), Subject: Los Esteros NOx Conversion, May 20, 2010; email from Vijay Patel (Deltak) to Paul C. Berthiaume, P.E. (Chief Mechanical Engineer, Calpine Corp.), October 6, 2010.

[21] *See generally* M. Schorr & J. Chalfin, *Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?*, GE Power Generation, Publication No. GER 4172, September, 1999.

limit below 2.0 ppm would also likely require an increase in the frequency of catalyst change-outs to maintain compliance. This would have both cost impacts and ancillary environmental impacts, because the old catalyst must be disposed of as hazardous waste, because the larger amount of catalyst needed would generate more spent catalyst to be disposed of, and because additional energy and natural resources would need to be used to produce the new catalyst. A NO_x permit limit below 2.0 ppm limit would also result in additional maintenance, which adds to operating costs and requires maintenance outages during which the plant is unavailable to meet demand. For example, achieving very low NOx limits would require the seals in the SCR system to be maintained to very tight tolerances to minimize the amount of NOx that may slip by them. With a NO_x permit limit below 2.0 ppm, it is likely that more frequent outages will be required to inspect and maintain these seals, which adds to the cost and could significantly impact the plant's availability to support the grid.

Finally, assuming that an SCR system could be designed to achieve emissions below 2.0 by increasing the amount of catalyst or the size of the catalyst bed, the system would have to be able to operate to maintain compliance at all times, including during periods of transient load. Compliance is much more difficult during such periods because the SCR system's ammonia injection control system is limited in how quickly it can respond to rapidly changing conditions. The amount of ammonia being injected is determined based on turbine operating conditions and the NO_x concentration at the stack exhaust. There is an optimal amount of ammonia based on the incoming NO_x and the ammonia injection system provides a slight excess to ensure the NO_x emissions are minimized while ammonia slip levels are also minimized. When gas turbine load is ramped quickly, its NOx emissions can change much more rapidly than the ammonia injection system can respond due to the lag time in the ammonia injection control system and the NO_x continuous emission monitor. This control system lag and continuous emission monitor (CEM) lag time make meeting a permit limit below 2.0 ppm NO_x averaged over one hour much more difficult during rapid load changes.

Designing an SCR system to consistently maintain compliance with a limit below 2.0 ppm would also be more difficult because transient load conditions and fast ramp rates are expected to become more common in the coming years as California moves to more renewable power generation. Renewable sources of electrical power such as wind and solar are much more intermittent and uncertain that traditional power plants. Fossil fuel fired plants will be needed to fill in the gaps when the sun is not shining or the wind is not blowing, and they will be required to ramp up quickly when needed and then ramp back down when renewable sources come back on-line.[22] For this reason, facilities such as the LECEF Phase II project are expected to experience a significantly increased amount of transient load conditions, although it is difficult to predict with certainty exactly how these facilities will need to operate. An SCR system would need to be designed to operate at a very high degree of efficiency in order to ensure that it would be able to maintain compliance with a short-term NOx limit below 2.0 during all potential transient load conditions. Moreover, given the uncertainty as to how exactly the facility will need to operate in support of additional renewable generation, it would be difficult to predict the maximum design

[22] Integration of Renewable Resources, Operational Requirements and Generation Fleet Capability at 20% RPS, August 31, 2010, California ISO, pg. iii.

parameters that would be needed to ensure compliance.

Based on all of this analysis, the District has concluded that there is insufficient evidence on which to make a determination that a lower NOx emissions limit can be justified as BACT for this facility. Although it may be possible in theory to design an enhanced SCR system that could potentially be more effective in reducing NOx, there is substantial uncertainty as to how effective such an enhanced system would actually be in consistently achieving a lower permit limit. Moreover, even if a lower limit could theoretically be achieved, there is substantial uncertainty over how the SCR system would need to be designed to do so given the changes in power plant operating scenarios that are expected as California moves to more renewable power sources, and in particular the greater incidence of transient load conditions. The District is also concerned that if the facility is subjected to a lower limit and finds that it cannot achieve it during transient loads, the facility would not be able to be operated to support renewable resources as readily which would hinder California's efforts to develop those resources. And finally, the District is also mindful of the additional costs and ancillary adverse environmental impacts that would be associated with an enhanced SCR system. Although additional costs and ancillary impacts can be acceptable where justified by the increased effectiveness of a better add-on control system under a BACT analysis, there is little clear indication that additional NOx reductions beyond the very stringent 2.0 ppm levels that are currently being achieved would be worth it here (to the extent that any additional reductions could even be obtained in practice). Given the high degree of uncertainty regarding what level of additional NOx reductions could actually be achieved, what would be required from a technical standpoint to achieve any such additional reductions, and what the adverse ancillary impacts would be, the technical information available at this point does not provide a sufficiently certain basis to support a BACT determination that a NOx emissions limit below 2.0 should be required. The District has considered all of this evidence and has concluded that the evidence does not support imposing a NOx emissions limit below 2.0 ppm as BACT for the LECEF Phase II project.

- ***Consideration of Excursion Language:***

The District also considered whether the excursion language in the Phase II ATC meets current BACT requirements. (See Condition 19.g, allowing up to 320 hours per year for short-term excursions above the 2.0 ppm NOx limit up to 5.0 ppm NOx.) The District found that a number of similar facilities have NOx permit limits at 2.0 ppm (1-hour) with no excursion language, suggesting that 2.0 ppm without excursion language is the achieved-in-practice level of emissions control. In addition, the applicant has not voiced any objection to removing the excursion language from the permit. The District has therefore concluded that the excursion language is not consistent with current BACT and should be removed from the renewed ATC.

- ***Conclusions:***

Based on the foregoing review, the District has concluded that the NOx BACT limit of 2.0 ppm, averaged over one hour, will meet current BACT (with the excursion language removed).

III.A.2. Carbon Monoxide (CO)

The Phase II Authority to Construct established a CO limit of 9.0 ppm averaged over three hours. The District established the CO limit at this level based on concerns that using water injection to reduce NOx formation during combustion would cause increased CO formation because of lower flame temperatures. Lower flame temperature decreases combustion efficiency, which results in CO formation due to incomplete combustion. When LECEF 2 was originally permitted, the operator provided test data demonstrating the effect of the increase in the water injection rate that would be required to allow the turbines to comply with the 2.0 ppm NO_x limit. As the NO_x emission concentration after abatement by the SCR system 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 was expected that the CO emissions would increase further as the NOx emissions are controlled to meet a 2.0 ppmv limit on NO_x. Based on the demonstrated increases in CO emissions that occurred as the water injection rates were increased to reduce NO_x emissions, the applicant requested that the maximum allowable (not-to-be-exceeded) CO limit be increased to 9.0 ppmv. The District agreed that the proposed CO limit of 9.0 ppm was reasonable when combined with the 2.0 ppm NOx limit. Thus, the ATC was issued with a CO limit of 9.0 ppmvd averaged over three hours.

The District has reviewed this BACT determination and has concluded that current BACT requires a lower limit. The District reviewed a number of other combined-cycle power plants to evaluate what CO emissions limits have been achieved in practice, based on a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse. The search results from these databases are summarized in Table 5 below.[23] The table identifies both NO_x limits and CO limits because they are dependent on each other. With a lower NO_x limit, greater leeway must be given in the CO limit because reducing NO_x normally results in increasing CO. The projects are presented in order of descending CO concentrations and averaging times.

Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers

Facility	NO_x ppmvd @ 15%O_2	CO ppmvd @ 15%O_2	Operational Status
Hanging Rock, OH-0252	3 (3-hr)	9 (24-hr)	Unknown
FPL Turkey Point, FL-0263	2 (24-hr)	8 (24-hr)	Unknown
La Paloma, SJVAPCD	2.5 (1-hr)	6 (3-hr)	In Operation
Mountainview San Bernadino County	2.5 (1-hr) 2.0 (1-hr) in 2005	6 (3-hr)	In Operation

[23] In addition to reviewing recent permit limits, the District also reconsidered its BACT technology choice analysis. The facility will use an oxidation catalyst and good combustion practices as the BACT technologies to control CO emissions, as discussed in the District's evaluation for the initial Phase II ATC. The only additional control technology available for use in controlling CO emissions is EMx, which the District evaluated above and concluded is not as effective as SCR and is therefore not BACT. The District has therefore concluded that the current technology choice for CO continues to satisfy the BACT requirement.

Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers			
Facility	**NO_x ppmvd @ 15%O_2**	**CO ppmvd @ 15%O_2**	**Operational Status**
Three Mountain, Shasta County	2.5 (1-hr)	4 (3-hr)	Not Built
SMUD Clay Station, SMAQMD	2 (1-hr)	4 (3-hr)	Unknown
Elk Hills, SJVAPCD	2.5 (1-hr)	4 (3-hr)	In Operation
Sunset Power, SJVAPCD	2 (1-hr)	4 (3-hr)	Unknown
Palomar Energy Project	2 (1-hr)	4 (3-hr)	In Operation
Sacramento Municipal Utilities District, Consumnes	2 (1-hr)	4 (3-hr)	In Operation
San Joaquin Valley Energy Center	2 (1-hr)	4 (3-hr)	Not Built
Calpine Facility Sutter, Feather River AQMD	2.5 (1-hr)	4 (24-hr)	In Operation
Sierra Pacific Power Company, Tracy Station, NV-0035	2 (3-hr)	3.5 (3-hr)	Unknown
ANP Blackstone, MA-0024	2 (1-hr) No Steam 3.5 (1-hr) Steam Inj.	3.0 (1-hr)	In Operation
Welton Mohawk, AZ-0047	2 (3-hr)	3 (3-hr)	Unknown
Colusa Generating Station	2 (1-hr)	3 (3-hr)	Not Built
Rocky Mountain Energy Center, CO-0056	3.0 (1-hr)	3	In Operation
Turner Energy Center, OR-0046	2.0 (1-hr)	2.0 (3-hr)>70% load, 3.0 (3-hr)<70% load	Not Built
Berrian Energy Center, MI-0366	2.5 (24-hr)	2.0 (3-hr)	Unknown
BP Cherry Point, WA-0328	2.5 (3-hr)	2 (3-hr)	Unknown
Wanapa Energy Center, OR-0041	2 (3-hr)	2 (3-hr)	Not Built
Morro Bay – Duke	2 (1-hr)	2 (3-hr)	Not Built
Carlsbad Energy Center, SDAPCD	2 (1-hr)	2 (1-hr) 2 (3-hr) Transient	Not Built
Goldendale Energy, WA-0302	2 (3-hr)	2 (1-hr)	In Operation
Sumas Energy 2, WA-0315	2 (3-hr)	2 (1-hr)	Not Built

Table 5: Recent BACT Carbon Monoxide Permit Limits for Large Combined-Cycle Combustion Turbines/Heat Recovery Boilers			
Facility	**NO_x ppmvd @ 15%O_2**	**CO ppmvd @ 15%O_2**	**Operational Status**
IDC Bellingham, MA	1.5/2.0 (1-hr)	2 (1-hr)	Not Built
Magnolia, SCAQMD	2 (3-hr)	2 (1-hr)	In Operation
Sithe Mystic, MA-0029	2 (1-hr)	2 (1-hr)	In Operation
Sithe Fore River, MA	2 (1-hr)	2 (1-hr)	In Operation
Russell City Energy Center	2 (1-hr)	2 (1-hr)	Not Built
Southern Company McDonough Combined Cycle, GA-0127	6 (May thru Sept) 15 (30 day Rolling Avg)	1.8 (3-hr)	In Operation
Kleen Energy Systems, CT-0151	2 (1-hr)	0.9 (1-hr) No Duct Burner 1.7 (1-hr) Duct Burner	Not Built
CPV Warren, VA-0308, Scenario 1, GE Frame 7FA	2 (1-hr)	1.3 (3-hr) No Power Aug. 1.8 (3-hr) Power Aug. No Duct Burner 2.5 (3-hr) Power Aug., Duct Burner	Not Built
CPV Warren, VA-0308, Scenario 2, GE Frame 7FA	2 (1-hr)	1.2 (3-hr) without Duct Burner 1.3 (3-hr) Duct Burner	Not Built
CPV Warren, VA-0308, Scenario 3, Siemens F-Class	2 (1-hr)	1.8 (3-hr) No Duct Burner 2.5 (3-hr) with Duct Burner	Not Built

Notes:

a. Information presented is from a database search of a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse for recent permits issued for natural gas fired combined-cycle power plants.

b. Facilities from the EPA Clearinghouse are identified with an EPA clearinghouse number, which is a two-letter state code followed by a four-digit number. All other facilities are from the CARB Clearinghouse.

The review of permit limits shows that most permitting agencies appear to be converging on a consensus of 2.0 ppm as BACT for CO, which is the BACT 2 "achieved in practice" level of control for this type of facility. There are also several facilities that have been permitted with permit limits less than 2 ppm, as shown in the table, but these facilities do not establish that lower limits have been achieved in practice. One of the three facilities with CO limits less than 2 ppm has not been built (CPV Warren) and another facility has been built but not operated (Kleen Energy), so there is no operational data available from either of these facilities to assess whether they are in fact able to achieve these permit limits. The third facility with a CO permit limit less than 2 ppm (McDonough) is operational, but this facility has a NO_x limit that is much higher than 2 ppm (6 ppm) so this facility is not comparable to the LECEF combined-cycle units. For combustion sources NO_x and CO emissions typically have an inverse relationship, with CO increasing as NOx emissions are reduced. Having a higher NO_x limit of 6 ppm makes it possible to keep CO emissions at lower levels, but the District prioritizes NOx reductions over CO reductions because the Bay Area is in compliance with CO air quality standards but not in compliance with ozone standards. (NOx is a precursor to ozone formation.) CO emissions below 2.0 ppm have not been achieved in practice for facilities with low NOx limits like the 2.0 ppm BACT limit that the District is imposing here. In addition, the McDonough facility's limit uses a 3-hour averaging period, making it easier to comply with than the more stringent 1-hour averaging period the District is imposing here. With a longer averaging time, short-term high-emissions fluctuations can be offset by other times during the averaging period with low emissions. A facility with a lower limit using a 3-hour averaging period therefore does not establish that the lower limit could be achieved with the more stringent 1-hour averaging period the District is requiring here.

The District also considered whether it would be technically feasible and cost-effective to require the LECEF Phase II project to meet an emissions limit below the 2.0 ppm achieved for similar combined-cycle facilities. This "BACT 1" analysis found that using a larger oxidation catalyst might be capable of meeting a CO permit limit below 2 ppm, although doing so could have additional implementation problems such as high back-pressure, which could adversely impact turbine operating performance and efficiency. In any event, even if achieving a limit below 2.0 would be technically feasible, it would not be cost-effective to do so under the District's BACT cost-effectiveness guidelines given the large costs involved.

The District reviewed information on the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining CO emissions below 1.5 ppm.[24] Based on three vendor estimates, the approximate cost of achieving a 1.5 ppm permit limit would be an additional $136,680 for the equipment (above what it would cost to achieve a 2.0 ppm limit) and a total annualized operating cost of $108,851.[25] The additional reduction in CO emissions would amount to approximately 9.8 tons per year, which results in an incremental cost-

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[24] A potential lower limit of 1.5 ppm provides a reasonable basis for this analysis because that number is in the middle of the range of permit limits below 2.0 found in the other permits the Air District reviewed. Given that the results of the cost-effectiveness analysis for a 1.5 ppm limit are well above what has been required at other similar facilities to achieve CO reductions, there is no reason to believe that any other limits below 2.0 ppm would be cost-effective for purposes of the BACT analysis.

[25] See vendor quotations from CMI Groupe, Nooter/Ericksen, Inc., Deltak, and Foster Wheeler.

effectiveness value of approximately $11,100 per ton of additional CO reduction.[26] Additionally, the total annualized costs of achieving a 1.5 ppm CO limit, calculated in accordance with EPA guidelines, would be approximately $507,523 per gas turbine, and the resulting emission reduction from the baseline emissions of 10 ppm CO would amount to 41.7 tons per year, resulting in a total (or "average") cost effectiveness value of over $12,200.[27] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.5 ppm CO permit limit cannot reasonably be justified as a BACT limit.[28]

Based on the foregoing analysis, the ATC's limit on CO of 9 ppm should be reduced to 2 ppm, averaged over one hour, to meet current BACT requirements.

III.A.3. Sulfur Dioxide (SO_2)

When the District issued the initial Phase II ATC, it evaluated BACT for SO_2 and determined that BACT required the use of clean-burning natural gas with a sulfur content not to exceed 1 gr/100 scf. The District has reviewed this BACT limit and found that it continues to satisfy current BACT standards. The District's BACT Guideline for this source category (Guideline 89.1.6) has not been revised since the initial Phase II ATC was issued, the standards for sulfur content in natural gas have not changed, there are no new control technologies that can feasibly be used to remove SO_2 from the emissions stream,[29] and the District has not found any other similar facilities

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[26] *See* Spreadsheet, Incremental Cost Effectiveness Analysis for CO Control From 2 to 1.5 ppmv, prepared by Barbara McBride, Calpine Corp., reviewed and amended by Weyman Lee, P.E., BAAQMD.

[27] *See* McBride, Calpine Corp., reviewed and amended by Weyman Lee, P.E., BAAQMD.

[28] The Air District has not adopted its own cost-effectiveness guidelines for CO, but a review of thresholds used by other agencies and specific BACT determinations by the District and others shows that additional CO reductions are not normally required as BACT where they would cost more than a few hundred to a few thousand dollars per ton. (*See* South Coast Air Quality Management District, Best Available Control Technology Guidelines, August 17, 2000, revised July 14, 2006, at 29; available at: www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power, Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005; U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005; BAAQMD Application No. 15487, Russell City Energy Center, Responses to Public Comments (Feb. 3, 2010), pp. 69-74; EPA Region 4, "National Combustion Turbine List," available at: www.epa.gov/region4/air/permits/national_ct_list.xls.) The costs per ton of additional reductions here would exceed these levels by a significant amount.

[29] Wet scrubbing and dry scrubbing technologies used at facilities combusting high-sulfur-content fuels are not feasible for combustion sources burning low-sulfur-content natural gas. The SO_x concentrations in the natural gas combustion exhaust gases are too low (less than 1 ppm) for the scrubbing technologies to work effectively or be technologically feasible or cost effective. These control technologies to remove sulfur in the exhaust are not feasible as a control technology for natural gas turbines.

that are using any better technologies. The District has therefore determined that current BACT for SO_2 for the combined cycle gas turbines is the exclusive use of the highest quality commercially available natural gas that meets the PG&E Gas Rule 21, Section C standard of less than 1.0 grains of sulfur per 100 scf.

The District also included an hourly numerical SO_2 mass emissions limit in the initial Phase II permit, although the numerical limit was not the basis for the BACT determination. The District has now determined that a numerical mass emissions limit is not appropriate as a permit limit for a pollutant such as SO_2. There are no add-on control technologies that are effective to reduce SO_2 emissions from a facility such as this, and SO_2 emissions are therefore not within the control of the operator beyond ensuring that low-sulfur fuel is burned. For this reason, there is no air quality benefit that would be gained from imposing a numerical emissions limit as BACT. Unlike other criteria pollutants such as NOx or CO, where the operator can design and operate its equipment and control systems to meet the applicable permit limit, SO_2 emissions will be what they will be based on fuel sulfur content and turbine combustion dynamics regardless of what actions the operator takes. Imposing a numerical mass limit as a permit condition therefore makes no difference from an operational perspective regarding what level of the emissions the facility will produce, and no difference in terms of the facility's impact on ambient air quality. Furthermore, a numerical mass emissions limit is not required by the BACT regulation. District regulation 2-2-206 defines BACT as either a "control device or technique" (Sections 2-2-206.1 and -206.3) or an "emission limitation" (Section 2-2-206.2 and -206.4), and does not require that both be imposed as permit requirements. As long as the most stringent control device or technique is required, BACT does not require a mass emissions limitation to be imposed as well through permit conditions where (as here) it is not warranted from an air quality perspective. For these reasons, the District is not intending to include a numerical SO_2 mass emissions limit in the renewed permit.

III.A.4. Particulate Matter (PM)

As with SO_2, the District's initial Phase II ATC evaluation determined that BACT for PM_{10} required the use of clean-burning natural gas with a sulfur content not to exceed 1 gr/100 scf.[30] The District has reviewed this analysis and has determined that it continues to meet current BACT requirements. The District's BACT Guideline for this source category has not been revised since the initial Phase II ATC was issued,[31] the maximum sulfur content in natural gas has not changed, and there are no new control technologies that can feasibly be used to remove PM_{10} from the

[30] *See* Final Determination of Compliance, Los Esteros Critical Energy Facility, Plant 13289, Combined-Cycle Conversion (Phase II), dated June 28, 2005, page 22. Clean burning natural gas was defined as a maximum sulfur content of 1.0 gr/100 scf.

[31] In addition, the California Air Resources Board's guidance on PM emissions from power plants has also not been revised since the initial ATC was issued, and continues to be consistent with the District's BACT determination. *See* Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999, pg. 34.

emissions stream.[32] The District has therefore determined that use of a high-efficiency inlet air filter and low-sulfur natural gas with good combustion practice are the BACT control technologies for the proposed LECEF Phase II project. For low-sulfur fuel, the highest quality commercially available natural gas is natural gas that meets the PG&E Gas Rule 21, Section C standard of less than 1.0 grains of sulfur per 100 scf. This PG&E standard is maximum sulfur content at any point in time.[33] Good combustion practice for the proposed gas turbines at LECEF Phase II includes maintaining the combustion system to minimize incomplete combustion,[34] optimizing efficiency to minimize fuel usage, and onsite visual tools for monitoring combustion dynamics and performing diagnostics.

The District has also determined that the PM_{10} hourly numerical emissions limits that were included in the initial ATC are not warranted under the BACT requirement, for similar reasons to those discussed in connection with the SO_2 BACT analysis above. The District's BACT regulations require the District to implement BACT either as a control device or technique (Regulation 2-2-206.1 and 2-2-206.3) or as an emission limitation (Regulation 2-2-206.2 and 2-2-206.4), and do not require both types of BACT limits. The control techniques described above will fulfill the BACT requirement for PM in accordance with Regulations 2-2-

[32] Add-on control devices such as electrostatic precipitators and baghouses are not achieved-in-practice for natural gas fired combustion turbines and are not technically feasible here. These devices are normally used on solid-fuel fired sources or others with high PM emissions, and are not used in natural gas fired applications which have inherently low PM emissions. The District is not aware of any natural gas fired combustion turbine that has ever been required to use add-on controls such as these. The District also reviewed the EPA BACT/LAER Clearinghouse and confirmed that EPA has no record of any post-combustion particulate controls that have been required for natural gas fired gas turbines. The District has therefore determined that these control devices are not achieved in practice for this type of facility. Furthermore, if add-on control equipment was installed it would create significant back pressure that would significantly reduce the efficiency of the plant and would cause more emissions per unit power produced. Also, these devices are designed to be applied to emissions streams with far higher particulate emissions, and they would have very little effect on the low-PM emissions streams from this facility in further reducing PM emissions. (For example, if a baghouse were installed on the turbines, the turbine exhaust at the *inlet* to the baghouse would contain less PM than is normally seen in baghouse *output*, after abatement. PM emissions from a baghouse are normally in the range 0.0013 to 0.01 grains per standard cubic foot (*see BAAQMD BACT/TBACT Workbook*, Section 11: Miscellaneous Sources), whereas PM emissions from the proposed LECEF turbines would be 0.0012gr/dscf.) It takes an emissions stream with a much higher grain loading for these types of abatement devices to operate efficiently. This low level of effectiveness (if any) also means that these types of control devices would not be cost-effective, even if they could feasibly be applied to this type of source. For all of these reasons, post-combustion particulate control equipment is not technologically feasible/cost effective for the LECEF turbines.

[33] PG&E's Gas Rule 21, Section C requires the quality of gas received into the pipeline system to have a maximum sulfur content of 1.0 grain per 100 scf. The average content is expected to be less than 0.25 grains per 100 scf. The District has based its calculations of annual emissions on this 0.25 grain per 100 scf average sulfur content. Note that a portion of the sulfur contained in natural gas is intentionally added as an odorant to allow for the detection of leaks which would be a safety concern. PG&E Gas Rule 21, Section C can be found at: http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml.

[34] Unburned hydrocarbons from the natural gas that are not fully combusted may condense to form PM. Permit conditions limit the CO emissions to 2 ppm over a 1-hour averaging period. This high level of control of CO indicates unburned hydrocarbons are also well controlled, thereby minimizing PM emissions. Good combustion practice will be ensured by the use of a CEM to monitor CO emissions. Compliance with the stringent CO emissions limits in the permit indicates that good combustion practices are being implemented.

206.1 and 2-2-206.3. The District has concluded that imposing a numerical emissions limit, in addition to requiring BACT technologies, would not be warranted given that there are no add-on control devices that the facility can use to control PM emissions. Assuming the facility is using good combustion practices, PM emissions will be determined by the amount of sulfur in the fuel and the way that the combustion equipment functions, which are factors that are not within the control of the operator. PM therefore presents a different situation than other pollutants such as NOx or CO where the project owner can design its add-on control systems to achieve the required level of emissions and ensure that it will comply with its emission limits by operating the add-on control systems properly. For these reasons, the District does not intend to include numerical hourly PM_{10} limits in the renewed ATC.

This BACT determination is consistent with guidance from the California Air Resources Board in setting BACT for natural gas-fired gas turbines.[35] This BACT determination is also consistent with District BACT Guideline 89.1.6, which specifies BACT for PM_{10} for combined-cycle gas turbines with rated output of ≥ 40 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of ≤ 1.0 grains per 100 scf.[36] These guidance documents do not suggest that a numerical emissions limit should be required as a BACT permit condition.

III.A.5. Precursor Organic Compounds (POC)

The initial Phase II ATC included a POC limit of 2.0 ppm (3-hour average). The District has reviewed this limit and has determined that current BACT requires a POC limit of 1.0 ppm (1-hour average). This determination is based on a review of permit limits and emissions test data from similar facilities.

The District reviewed permit limits from similar facilities to determine the appropriate POC permit limit for the LECEF Phase II combined-cycle gas turbines, which are summarized in Table 6 below.

Table 6: Recent BACT NO_X and POC Permit Limits for Large Combined-Cycle Turbines

Facility	Date	NO_x ppmvd@15%O_2	POC Emissions Limit
Goldendale Energy Project, WA-00302	2/2001	2 (3-hr)	6 ppm (1-hr)
Sumas Energy 2, WA-0315	4/2003	2 (3-hr)	420 lb/day (6.4 ppm (24-hr))
Sierra Pacific Power Company, Tracy Station, NV-0035	8/2005	2 (3-hr)	4.0 ppm (3-hr)

[35] Guidance for Power Plant Siting and Best Available Control Technology, California Air Resources Board, Stationary Source Division, September 1999, pg. 34.

[36] *See* Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm

Table 6: Recent BACT NO_X and POC Permit Limits for Large Combined-Cycle Turbines			
Facility	**Date**	**NO_x ppmvd@15%O_2**	**POC Emissions Limit**
Rocky Mountain Energy Center, CO-0056[a]	5/2006	3.0 (1-hr)	0.0029 lb/MMBtu (2.3 ppm)
Wellton Mohawk, AZ-0047	12/2004	2 (3-hr)	3 ppm (3-hr)
Elk Hills, SJVAPCD	2000 2003	2.5 (1-hr)	2 ppm (3-hr)
Palomar Energy Project, SDAPCD	8/2003 4/2006	2 (1-hr)	2 ppm (3-hr)
Morro Bay – Duke, SLOAPCD	8/2004	2 (1-hr)	2 ppm (3-hr)
San Joaquin Valley Energy Center, SJVAPCD	1/2004	2 (1-hr)	2 ppm (3-hr)
Three Mountain, Shasta County	1999	2.5 (1-hr)	2 ppm (1-hr)
Magnolia, SCAQMD	5/03	2 (3-hr)	2 ppm (1-hr)
Colusa Generating Station, CCAPCD	4/2008	2 (1-hr)	2 ppm (1-hr)
Carlsbad Energy Center	TBD	2 (1-hr)	2 ppm (1-hr) Normal 2 ppm (3-hr) Transient
Delta Energy Center, BAAQMD	2/2000 5/2002	2.5 (1-hr)	5.33 lb/hr or 0.00251 lb/MMBtu (2 ppm)
La Paloma, SJVAPCD	12/2000 2003	2.5 (1-hr)	0.7 (3-hr) as Propane 1.9 (3-hr) as Methane
Southern Company McDonough Combined Cycle, GA-0127	1/2008	6 (May 1 to Sept 30) 15 (Remainder), 30 day Rolling Average	1.8 ppm (3-hr) Duct Firing 1.0 ppm (3-hr) No Duct
SMUD Clay Station, SMAQMD		2 (1-hr)	1.4 ppm (3-hr)
Sunset Power, SJVAPCD	12/2003	2 (1-hr)	1.4 ppm (3-hr)
Sacramento Municipal Utilities District, Consumnes	9/2003 2/2006	2 (1-hr)	1.4 ppm (3-hr)
ANP Blackstone, MA-0024	4/1999	2 (1-hr) No Steam Inj. 3.5 (1-hr) Steam Injection	1.4 ppm (1-hr) no steam 3.5 ppm (1-hr) steam inj.
Los Medanos Energy Center, BAAQMD	1999 2001	2.5 (1-hr)	3.8 lb/hr or 0.0017 lb/MMBtu (1.4 ppm)
Mountainview San Bernardino County	3/2001 12/2005	2.5 (1-hr) Lowered to 2.0 (1-hr) in 2005	3.47 lb/hr (0.00163 lb/MMBtu) (1.3 ppm)
FPL Turkey Point, FL-0263	2/2005	2 (24-hr)	1.3 ppm (UNK) No Duct 1.9 ppm Duct Firing

Table 6: Recent BACT NO_X and POC Permit Limits for Large Combined-Cycle Turbines			
Facility	**Date**	**NO_x ppmvd@15%O_2**	**POC Emissions Limit**
CPV Warren, VA-0308 Scenario 1 GE Frame 7FA	1/2008	2 (1-hr)	0.7 ppm (3-hr) No Duct 1.0 ppm (3-hr) Duct Firing 1.4 ppm (3-hr) Power Aug.
CPV Warren, VA-0308 Scenario 2 GE Frame 7FA	1/2008	2 (1-hr)	0.7 ppm (3-hr) No Duct 1.0 ppm (3-hr) Duct Firing
CPV Warren, VA-0308 Scenario 3 Siemens STG6-5000F	1/2008	2 (1-hr)	0.7 ppm (3-hr) No Duct 1.4 ppm (3-hr) Duct Firing
CPV Vaca Station, YSAQMD Siemens SGT6 5000F or GE Frame 7FA	TBD	2 (1-hr)	2 ppm (1-hr)
Turner Energy Center, OR-0046	1/2005	2.0 (1-hr)	1 ppm (3-hr)
Calpine Facility, Feather River AQMD	12/2000	2.5 (1-hr)	1 ppm (24-hr)
IDC Bellingham, MA	9/2000	1.5/2.0 (1-hr)	1 ppm (1-hr)
Metcalf Energy Center, BAAQMD	2001 2005	2.5 (1-hr)	2.7 lb/hr or 0.00126 lb/MMBtu (1 ppm)
Russell City Energy Center, BAAQMD	2010	2 (1-hr)	2.86 lb/hr or 0.00128 lb/MMBtu (1 ppm)

Notes:
a. Information presented is from a database search of a search of EPA's BACT/RACT/LAER Clearinghouse and ARB's BACT Clearinghouse for recent permits issued for natural gas fired combined-cycle power plants
b. Facilities from the EPA Clearinghouse are identified with an EPA clearinghouse number, which is a two-letter state code followed by a four-digit number. All other facilities are from the CARB Clearinghouse.

This review shows a number of facilities with limits of 1.0 ppmvd @ 15% O_2 averaged over one hour. Within the District's jurisdiction, the Metcalf Energy Center has been meeting this permit limit with an oxidation catalyst for over a year and demonstrates that this level of emissions reduction can be achieved for this type of facility.[37]

Table 6 also shows one facility, the CPV Warren plant, with a permit limit of 0.7 ppm for turbine-only operation (no duct firing), and so the District considered whether current BACT should be

[37] The District also considered whether there were any additional control technologies available to reduce POC emissions. Like CO emissions, POC emissions are a product of incomplete combustion, and so technologies that are effective to reduce CO emissions will also be effective to reduce POC emissions. The BACT technology review for CO is therefore also applicable to POC. As noted above in the discussion of CO, the facility will use an oxidation catalyst and there are no other more effective control technologies available.

set at 0.7 ppm. The District notes that the CPV Warren plant has not been built at this time, and there is no operational data indicating whether this limit is actually achievable. This permit does not establish that the limit has actually been achieved in practice.

The District nevertheless considered whether it would be technologically feasible and cost-effective to impose a POC limit at this level. The District has concluded that even if it would be technically feasible to achieve 0.7 ppm, it would not be cost-effective to do so given the high costs involved. The District calculated the cost effectiveness of installing a larger oxidation catalyst designed to maintain POC emissions below 0.7 ppm (1 hour average).[38] Based on the costs and emissions reduction benefits of these analyses, the cost of achieving a 0.7 ppm permit limit would be an additional $108,851 per year (above what it would cost to achieve a 1.0 ppm limit), and the additional reduction in POC emissions would be approximately 0.8 tons per year, making an incremental cost-effectiveness value of $132,700 per ton of additional POC reduction.[39] Moreover, the total cost of achieving a 0.7 ppm POC limit (as opposed to the incremental costs of going from 1.0 ppm to 0.7 ppm) would be over $507,523 per year, and the total emission reductions from 2.0 ppm from the turbine to a 0.7 ppm limit would be 3.6 tons per year, resulting in a total (or "average") cost-effectiveness value of $140,200 per ton.[40] The District has adopted guidelines that establish that the maximum cost that the District will require a facility to bear to reduce POC emissions under the BACT requirement is $17,500 per ton.[41] Based on the high costs (on a per-ton basis) and the relatively little additional POC emissions benefit to be achieved (on a per-dollar basis), requiring a 0.7 ppm POC permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 0.7 ppm limit would be substantially more expensive, on a per-ton basis, than what other similar facilities are required to achieve.

The District has therefore determined that BACT for POC for this facility is the use of good combustion practice with abatement by an oxidation catalyst for each gas turbine with a permit limit of 2.71 lb per hour, which corresponds to 1.0 ppmvd @ 15% O_2. Compliance with the POC permit limits will be demonstrated by annual source tests.

Based upon the results of this analysis, the District concludes that the POC emission limit should be reduced to 1.0 ppmv @ 15% O_2.

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[38] See vendor quotations from: (1) Vijay Patel, Deltak email to Paul Prusi, Calpine re Los Esteros Permitting, on March 17,2010; (2) Larry Oprea, Foster Wheeler email to Paul Prusi, et al (Calpine) re Los Esteros Emissions, on March 23, 2010; (3) Mike Filla, Nooter-Ericksen email to Paul Prusi, Calpine re Urea SCR Catalyst System on November 11, 2009; (4) Craig Smith, CMI Groupe email to Paul Prusi, Calpine re CO Catalyst Costs on April 8, 2009.

[39] *See Spreadsheet LECEF POC Cost Effectiveness Incremental.*

[40] *See Spreadsheet LECEF POC Cost Effectiveness full to 0.7.*

[41] *See* Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

III.A.6. Startup and Shutdown Emissions

The initial Phase II ATC included a limit on turbine startups of 240 minutes and a limit on turbine shutdowns of 30 minutes. The District has reviewed these limits and has concluded that current BACT would require shorter time limits on startups, as explained in detail below. In addition, the District has also decided to include numeric mass emission limits for emissions during startups and shutdowns as it has done with other recent power plant permits. The District's analysis is set forth in the following paragraphs.

III.A.6.i. – Turbine Startups

Emissions during startups are higher than during normal steady-state operation for several reasons. One reason is that the turbines are not operating at full load where they are most efficient. Another reason is that turbine exhaust temperatures are lower than during steady-state operation, and post-combustion emissions control systems such as the SCR catalyst and oxidation catalyst do not function with full efficiency at these lower temperatures. The District evaluated the extent to which the facility could feasibly minimize startup emissions to ensure that it meets current BACT standards.

- ***Startup Control Technologies:***

First, the District reviewed what control devices or techniques would be required by BACT to control startup emissions. The existing startup limits were based on using best work practices designed to minimize the amount of emissions that occur during startups. This is accomplished by optimizing the start-up sequence so that the unit reaches the point when its emissions control technologies are functioning at an optimal level with the least emissions possible. This was the only startup emissions control technique that was available at the time the District issued the initial Phase II ATC.

To determine whether this analysis still meets current BACT, the District reviewed additional emerging technologies that have been developed recently that can further reduce startup emissions from large combined-cycle facilities. The District examined the recently-developed "Fast Start" technology, which uses an integrated plant design that bypasses the steam turbine during startups so that the facility can come up quickly while the steam turbine is still coming up to operating temperature. Bypassing the steam turbine in this way avoids the main reason for the higher startup emissions for conventional combined-cycle technology, which result from the additional time it takes for the steam turbine to warm up. This technology is marketed by GE under the name "Rapid Response" and by Siemens under the name "Flex Plant". The District also examined low-load "turn-down" technology, which helps the turbine keep emissions low at low operating load and therefore could potentially benefit startup emissions since startups involve some low-load operation as the turbine is ramping up to full load. This technology is marked by GE under the name "Op-Flex".

These emerging technologies were developed primarily for larger frame/utility-size turbines, however, and not for the smaller aeroderivitive turbines like those used at the LECEF facility.

Aeroderivitive turbines like the LM6000s at LECEF are already designed for fast startup and shutdown times, and they are predominantly used in simple-cycle plants. In contrast, larger frame/utility turbines are predominantly used in combined-cycle plants that require additional time to startup (the HRSG and steam turbine in a combined-cycle plant extend the startup duration). Efforts to develop startup emissions control technologies have therefore focused on the frame/utility-size turbines where reducing startup times has the most impact. As a result, these technologies are currently not as well-developed in aeroderivitive applications, and are not available for use in the LECEF Phase II project.[42] More rudimentary fast-start type designs are available for LM6000 turbines, but these involve the use of a less-efficient single-pressure steam turbine system. The LECEF Phase II project will use a more efficient multi-pressure reheat steam turbine system. This multi-pressure reheat steam turbine will give the facility a higher overall efficiency, which results in less fuel consumption, lower greenhouse gas emissions, and lower criteria pollutants per unit of power output during steady-state operation. These efficiency gains will provide benefits during all periods of operation, not just during startups, and so it is less preferable to require a single-pressure system even if it could provide some measure of startup benefit. The District has therefore concluded that there are no recent developments in startup control technologies that would be available for use with the LECEF Phase II project, and thus that best work practices is still the BACT control technique.

- ***Startup Limits:***

To determine appropriate BACT emission limits for startups, the District evaluated what startup emissions have been achieved in practice and what can feasibly be achieved for this project. Aeroderivitive turbines such as the LM6000s at this facility are most often used in simple-cycle peaking applications, and so the District did not find many similar facilities to which to compare this project. The one similar facility with startup limits that can be used to compare with this project is the Donald Vonraesfeld power plant in Santa Clara, CA. That facility uses combined-cycle LM6000 turbines, and is achieving startup emission limits of 41 pounds of NOx, 35 pounds of CO and 2 pounds of POC per startup, with startup duration not to exceed 180 minutes.[43] These startup limits are achieved in practice for purposes of BACT, and the LECEF Phase II project will be required to meet limits at least as stringent as these.

[42] *See* Letter from Eddy Wacek (LM6000 Business Operations Manager, GE Power & Water, Aero Energy) to Mitchell D. Weinberg (Director, Project Development, Calpine), May 19, 2010 at 1 ("The OpFlex suite of flexibility products is designed for GE's Heavy Duty (Frame) Gas Turbines and not the Aeroderivitive Gas Turbines. Aeroderivitive technology is, by its nature, highly flexible and already incorporates many of the features offered for GE's Heavy Duty Gas Turbines OpFlex products."); *see also id.* at 2 ("Rapid Response is a patented, integrated combined cycle system for the GE's Heavy Duty Gas Turbine power plants. It is designed to allow faster starting of the overall plant, coupled with faster starting of the gas turbines. Rapid Response is not currently offered for Aeroderivatives because their inherent flexibility, size, and relative exhaust temperature already allows for Aeroderivative plant designs with greater overall responsiveness"); *see also* telephone note of conversation between Weyman Lee and Ben Beaver, Siemens Corp. on August 30, 2010 re the availability of "Flex Plant" technology for aeroderivative turbines.

[43] *See* BAAQMD permit for Silicon Valley Power Von Raesfeld Power Plant, Site No. B4991, Condition No. 24252.

The District then evaluated startup data from the existing Phase I simple-cycle project, with an extrapolation from that data presenting an estimate what startup emissions could be achieved when the facility is converted to combined-cycle operation. Startups for the combined-cycle mode will require the turbine to be held at about 40% load for approximately 40 minutes to allow the HRSG to warm up and to initiate the steam cycle. In addition, it will take approximately 30 minutes for the SCR system to warm up to a sufficiently high operating temperature for ammonia injection to commence, and then approximately 10 minutes after that the SCR system to become fully effective. During that 10-minute period of early ammonia injection, the SCR system will be operating at only around 60% NOx reduction. When the turbine reaches the end of its 40-minute low-load hold period, it will then start to ramp up to full desired load, which will be reached after approximately 70 minutes. At that point, NOx emissions will be relatively low but will fluctuate somewhat as the SCR system settles into balance and begins to achieve optimal performance. The system is expected to be able to achieve compliance with the steady-state NOx limit of 2.0 ppm by 120 minutes into the startup under this analysis.[44]

This analysis of the emissions that would be involved during startups estimated what emissions rates would be minute-by-minute during the entire 120-minute startup period. Aggregating the minute-by-minute emissions projections, the analysis estimates that total emissions from the entire startup would be 40.2 pounds of NOx.[45] This analysis shows that the LECEF Phase II project should be able to meet the same 41-pound emission limit that is achieved-in-practice based on the Donald Vonraesfeld facility. A 41-pound NOx limit for startup emissions would leave very little compliance margin over the District's projection based on the analysis from the Phase I data, but Calpine has committed to ensuring that emissions do not exceed this level using NOx control techniques such as commencing ammonia injection at the earliest possible time during the startup and maximizing the use of water injection to keep NOx emissions as low as possible. The District has determined that Calpine should reasonably be able to comply with the 41-pound limit using these measures.

For CO, the startup emissions analysis shows that the LECEF Phase II project should be able to achieve startup emissions substantially below the 35 pounds that the Donald Vonraesfeld facility is achieving. The startup analysis predicts emissions of 18.4 pounds of CO per startup.[46] Based on this analysis, the District has concluded that a not-to-exceed permit limit of 20 pounds per startup represents the most stringent permit limit that will be consistently achievable. A permit limit of 20 pounds provides a small compliance margin to ensure that the limit will be achievable in the event that the startup analysis the District relied on turns out to be an under-estimate.

For POC, there is little operational data available from the LECEF Phase I operation because POC emissions are not recorded with CEMs. The District was therefore not able to obtain an estimate of POC performance based on extrapolating from operational data as it did with NOx and CO. Instead, the District is basing its POC BACT limit for startups on the 2-pound emissions

[44] *See* spreadsheets, "LECEF Mock Startup NOx 10-29-2010" and , "LECEF Mock Startup Event CO 10-29-2010". These spreadsheets are based on actual startup operating data from the LECEF Phase I simple-cycle facility, with estimates made about how the equipment would operate after conversion to combined-cycle operation.

[45] *See* spreadsheet, "LECEF Mock Startup NOx 10-29-2010".

[46] *See* spreadsheet, "LECEF Mock Startup Event CO 10-29-2010".

limit achieved by the Donald Vonraesfeld facility. The NOx and CO data that the District evaluated for the LECEF Phase II project show that startup emissions from this project will generally be consistent with what the Donald Vonraesfeld facility is achieving, and at 2 pounds of POC the limit for that facility is very stringent. The District is therefore recommending a 2-pound POC limit as BACT for startups.

Finally, the District also considered whether to have separate limits for different startup situations as has been done in other power plant permits, which for example delineate different limits for cold startup and hot or warm startups. Separate limits are not required under BACT, but can be appropriate where circumstances warrant different treatment for different startup scenarios. The District has not found any evidence that there will be any substantial difference in emissions from different startup situations for the LECEF Phase II project. One of the main differences between cold startups and hot or warm startups at other facilities is that for cold startups, the combustion turbine needs to be held at low load for a longer time with cold startups because it takes longer to heat up the steam turbine. The combustion turbine cannot be ramped up to full load as quickly because full load generates more steam for the steam turbine, and as the steam turbine is warming up it cannot handle full steam output without excessive thermal stresses. For the LECEF Phase II project, however, some of the steam that is generated can be vented and not sent to the steam turbine, minimizing the delay in the combustion turbine coming up to full load. For this reason, the delays associated with cold startups are not expected to be any longer than those associated with hot or warm startups, and emissions are not expected to be substantially different. Moreover, the similar Donald Vonraesfeld power plant does not differentiate between different startup scenarios, and the startup limits the District is contemplating here would be consistent with the permit for that facility.

Based on this analysis, the District is recommending numerical emissions limits of 41 pounds of NOx, 20 pounds of CO, and 2 pounds of POC per startup. The District is also recommending lowering the limit on startup duration to 120 minutes. These permit conditions would be consistent with current BACT standards.

III.A.6.ii. – Turbine Shutdowns

For shutdowns, best work practices remains the only way to minimize emissions. There are no additional technologies that can shorten shutdowns or otherwise reduce shutdown emissions. For combined-cycle facilities, shutdowns can take up to 30 minutes because the combustion turbine must be ramped down slowly so as to prevent the steam-cycle equipment from being damaged by being cooled too rapidly (thermal shock). The District reviewed recent permits issued for combined-cycle facilities, and none have found that shutdowns could be accomplished in less than 30 minutes. During this shutdown period, the facility will not be able to achieve the very low NOx, CO and POC emission concentrations that it will achieve during stead-state operations because it will not be operating at normal loads where emissions performance is optimized. The turbines should be able to keep total emission rates (*i.e.*, the mass of pollutants emitted) within the rates for steady-state operations, however. These hourly rates are 4.6 lb/hr of NOx, 2.85 lb/hr of CO, and 0.81 lb/hr of POC. The turbines will therefore need to be exempted from the steady-state BACT limits on concentration for these pollutants, but not for the BACT limits on mass emission rates. Emissions will continue to comply with the BACT steady-state emission rates during shutdown operations. These emission rates are more stringent than what is being achieved by the comparable Donald Vonraesfeld power plant, which has shutdown emissions limits of 8 lb/hr NOx, 10 lb/hr CO and 1 lb/hr POC.

Based on this analysis, the District has determined that the 30-minute limit on shutdown duration is consistent with current BACT requirements. The District is also imposing numerical emissions limits applicable during shutdowns of 4.6 lb/hr of NOx, 2.85 lb/hr of CO, and 0.81 lb/hr of POC.

III.B. BACT for Six-Cell Cooling Tower

When the District issued the initial ATC, it determined that the proposed six-cell wet cooling tower was subject to BACT for PM_{10} since its potential to emit exceeded 10 pounds per day for that pollutant, based on information that the District had at that time. The District therefore imposed BACT conditions in the initial Phase II ATC requiring the use of drift eliminators with a maximum guaranteed drift rate of 0.0005% and a limit on total dissolved solids (TDS) in the cooling water of not more than 10,000 ppmw (mg/l).

Based on information from other facilities regarding cooling water TDS levels, the District explored whether the LECEF Phase II project would be able to keep TDS at lower levels to reduce PM_{10} emissions. TDS in the cooling water is a function of the TDS in the incoming water from the facility's water source and the number of times that the water is recycled through the cooling system. The District therefore evaluated the maximum TDS concentration in the water the facility has received from the City of San Jose water treatment plant over the last 4 years, which was 870 ppm as summarized in Table 7 below. Based on 6 cycles of concentration expected for LECEF, the resulting TDS value would be 6,000 ppmw.[47] Assuming that there may be some additional variability over the years, the District conservatively assumed that TDS could potentially be as high as 6,000 ppm, but would not reach the 10,000 ppm limit established in the initial ATC. With TDS kept below 6,000 ppm, and with drift eliminators with a maximum guaranteed drift rate of 0.0005%, total PM_{10} emissions would be only 4.8 tons per year.[48] Based on this level of emissions, the cooling tower is exempt from permitting requirements under District Regulations 2-1-128.4 (cooling tower exemption) and 2-1-319 (5 tpy restriction on exemption).

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[47] *See* email from B. McBride to W. Lee, dated 10/25/10, re Cooling Tower TDS Calculation Methodology. Cooling tower TDS is estimated by multiplying the recycled water TDS level by the cycles of concentration. A factor of 1.15 is also applied to account for the contribution from treatment chemicals and other makeup streams: 870 X 6 cycles X 1.15 = 6000.

[48] *See* cooling tower emissions calculations, Appendix A.

Table 7: City of San Jose Annual Average Recycled Water TDS Levels (ppmw (mg/l))[49]				
Total Dissolved Solids	**2007**	**2008**	**2009**	**2010**
Average	711	733	720	741
Maximum	797	870	767	777

The District has therefore concluded that the six-cell cooling tower is in fact not subject to the BACT requirement in District Regulation 2-2-301. The District is keeping the 0.0005% drift rate drift eliminator requirement and a lowered TDS requirement of 6,000 ppm in the permit, however, to ensure that the PM_{10} emissions remain below 10 pounds per day as an enforceable permit requirement.

III.C. BACT for Commissioning Period

The process of converting the facility to combined-cycle operation will involve a number of highly complex steps in which the gas turbines and associated HRSGs are carefully tested, adjusted, tuned and calibrated to operate in accordance with the design expectations. These activities are referred to as "commissioning activities" and are defined in the Authority to Construct to include all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and construction contractor to ensure safe and reliable steady-state operation.[50] The current BACT permit limits for the Phase II conversion process require emissions to be minimized during the commissioning period requiring (i) completion of all commissioning activities in the shortest period of time possible and with the lowest emissions feasible; (ii) tuning of the gas turbines to minimize emissions of CO and nitrogen oxides NOx at the "earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor"; (iii) installation, adjustment and operation of the SCR systems and oxidation catalyst systems at the earliest feasible opportunity in accordance with the manufacturer and construction contractor recommendations; (iv) a limit on the total combined number of hours when any of the gas turbines and/or HRSGs may be operated without its respective SCR and oxidation catalyst systems to no more than 250 hours; (v) a restriction on operation of the gas turbines without abatement except for "discrete commissioning activities that can only be properly executed without the SCR or [oxidation catalyst] system in place"; and (vi) submission of a plan describing the procedures to be followed during commissioning, the anticipated duration of each activity in hours and the purpose of such activity.[51] The District has reviewed these conditions and has not found any area in which they could feasibly be made more stringent. The same considerations on which these conditions were based in the initial Authority to Construct continue to hold true at the present time. The District has therefore determined that the commissioning conditions in the initial Authority to Construct continue to represent BACT for commissioning activities. In particular, the District has reviewed the applicant's preliminary construction schedule, which identifies the various activities and their planned sequencing during the

[49] *See* City of San Jose recycled water quality data at: http://www.sanjoseca.gov/sbwr/water-quality.htm.
[50] *See* definition of "Commissioning Activities", *infra* 36.
[51] *See id*, condition nos. 1 through 10, *infra 37 & 38*.

commissioning period.[52] While preliminary in nature, this schedule identifies a subcategory of commissioning activities, which, together, amount to a total of 228 hours.[53] This estimate of the number of hours provided the basis for the limitation on total number of hours of operation of the gas turbines and HRSGs without abatement equipment installed. The 22 additional hours reflected by this condition represents a margin of less than 10%, which represents a reasonable tolerance for unexpected events that might occur during commissioning. Moreover, if the construction contractor should complete all activities which must be performed without emissions abatement in a shorter period of time than the anticipated 228 hours and/or the maximum of 250 hours provided by the ATC, the facility must then begin meeting the stringent BACT limits applicable to normal operations.

[52] *See* Calpine Corp., Los Esteros Critical Energy Facility, Level 2 Summary Level Schedule, Rev 29, March 23, 2010, submitted by B. McBride (Calpine) to W. Lee (BAAQMD) on March 30, 2010.

[53] *See id.*, sheet 4 of 4.

IV. Emissions Calculations and Offsets Review

The second requirement for a renewal of an Authority to Construct under District Regulation 2-1-407.1.2 is that the facility must meet current emission offset requirements under District Regulations 2-2-302 and 2-2-303. These regulations require that the LECEF Phase II conversion project must provide Emission Reduction Credits (ERCs) to offset increases in emissions resulting from the project if such increases will be greater than specified threshold levels.

For the initial Authority to Construct for the Phase II conversion project, the District evaluated the amount of ERCs that the applicant would have to provide based on the permitted emissions increases allowed under the Authority to Construct. The District is now reevaluating the amount of ERCs that the applicant will need to provide based on the revised permit limits that will be included when the renewal is issued. The emissions calculations on which the District has calculated total facility emissions are set forth in Appendix A.

Regulation 2-2-302 requires that federally enforceable emission reduction credits must be provided for NO_x and POC increases at a ratio of 1.15:1.0 and 1.0:1.0, respectively. Under the renewed ATC, the Phase II conversion project will increase annual NO_x emissions from 74.9 tons to 95.2 tons, a 20.3 ton increase. At a ratio of 1.15:1.0, this increase requires 23.35 tons of ERCs to be provided. For POC, annual emissions will be decreasing when the Phase II conversion is implemented (from 21.0 tons to 12.3 tons), so no ERCs are required.

Pursuant to Regulation 2-2-303, emission reduction credits are required for SO_2 and PM_{10} emissions only for facilities with SO_2 or PM_{10} emissions that exceed 100 tons per year. The LECEF facility's emissions will be below these threshold levels (both under the current simple-cycle configuration and after the Phase II combined-cycle conversion), and so ERCs are not required to offset emissions of these pollutants. (Note however that the CEC has required the applicant to provide emission offsets for SO_2 as CEQA mitigation for the Phase II project.)

For CO, the Phase II conversion will not cause any increase in emissions, and the District's regulations would not require CO offsets even if there were any CO increase.

The ERCs required for the Phase II conversion project under the renewed ATC are summarized in Table 8 below.

Table 8: Emissions Offsets Required (tons/yr)

	NO_2	POC	CO	SO_2	PM_{10}
Current Facility Emission Permit Limits (tpy)	74.9	21.0	72.9	5.8	43.8
Combined-Cycle Facility Emission Permit Limits (tpy)	95.2	12.3	53.4	6.5	44.24
Emission Increase (tpy)	20.3	(8.7)	(19.5)	0.7	0.4

Table 8: Emissions Offsets Required (tons/yr)					
	NO_2	**POC**	**CO**	**SO_2**	**PM_{10}**
Offset Ratio	1.15:1.0	1.0:1.0	N/A	N/A	N/A
Offsets Required (tpy)	23.35	0	0	0	0

Calpine has surrendered ERCs from Certificate No. 1201 in the amount of 23.35 tons of NOx for this project. The submission of these ERCs satisfies current District offset requirements.

V. Permit Conditions for Authority to Construct Renewal

Consistent with the analysis provided above, the District has determined pursuant to District Regulation 2-1-407.1 that the following permit conditions satisfy current BACT and offset requirements under District Regulations 2-2-301, -302, and -303 for the LECEF Phase II conversion project. The Permit Conditions are revised from the initial Authority to Construct for the Phase II project as shown below with deletions shown in ~~strikethrough~~ text, and inserts by <u>underlined</u> text.

<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:	<u>The lesser of the first 120 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 19(a) and 19(c) and is in compliance with the emission limits contained in 19(a) through 19(d).</u>
Gas Turbine Shutdown Mode:	<u>The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(a) through 19(d) until termination of fuel flow to the Gas Turbine</u>
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO or NH_3) corrected to a standard stack gas oxygen concentration. For a~~n~~ <u>Gas Turbine</u> 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~~of power to the grid~~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

EQUIPMENT DESCRIPTION:

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:

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 48~~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~~10, A-4~~12~~12, A-~~6~~14 & A-~~8~~16) and OC Systems (A-~~1~~9, A-~~3~~11, A-~~5~~13 & A-~~7~~15) 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~~10, A-4~~12~~12, A-~~6~~14 & A-~~8~~16) and OC Systems (A-~~1~~9, A-~~3~~11, A-~~5~~13 & A-~~7~~15) 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. If necessary to ensure that accurate data is collected at all times, the owner/operator shall install dual span emission monitors. (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. If necessary to ensure accurate data is collected at all times, the owner/operator shall install dual-span monitors. (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 for each power train 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		114 lb/day	
~~d. PM_{10}~~	~~60 lb/day~~		~~60 lb/day~~	

~~e. SO_2 53.6 lb/day 53.6 lb/day~~

(basis: cumulative increase)

11. Within sixty (90) 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 6-1-301; SIP 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; and shall not exceed 4.68 lb/hour (1-hour rolling average) except during periods of gas turbine startup 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~~ 5 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: ~~BACT~~ Regulation 2-5)

    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~~2.0 ppmvd @ 15 % O_2 (~~3~~1-hour rolling average), except during periods of start-up or shutdown as defined in this permit; and shall not exceed 2.85 lb/hr (1-hour rolling average) except during periods of start-up 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~~ 1 ppmvd @ 15% O2 (~~3~~1-hour rolling average), except during periods of gas turbine start-up or shutdown as defined in this permit;

and shall not exceed 0.81 lb/hr (1-hour rolling average) except during periods of start-up 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 ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up do not exceed the limits established below. (Basis: BACT, Cumulative increase)~~The owner/operator shall operate the gas turbines so that the duration of a start-up does not exceed 240 minutes per event, or other time period based on good engineering practice that has been approved in advance by the District. 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. (Basis: Cumulative increase)~~

	Duration (Minutes)	NOx (lb/Event)	CO (lb/event)	POC (lb/event)
Start-Up	120	41	20	2

21. Turbine Shutdown: The owner/operator shall operate the gas turbines so that the duration of a shutdown does not exceed 30 minutes per event, or other time period based on good engineering practice that has been approved in advance by the District. Shutdown begins with the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. (Basis: Cumulative increase)

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~~175.6	~~1,009.6~~702.4	~~99~~94.1
POC	~~80.2~~20.2	~~320.8~~80.8	~~28.3~~12.3
CO	~~417.2~~97.0	~~1,668.8~~388.0	~~98.5~~53.4
SOx (as SO_2)	~~41.6~~	~~166.4~~	~~8.48.~~56.43
PM_{10}	~~60~~	~~240~~	~~43.8~~38.5
NH_3	~~198~~104	~~792~~416	~~118~~56.9

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 with the daily limits 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. The annual mass limits are based upon a rolling 8,760-hour period ending on the last hour. Compliance with the annual limits for NOx, POC, and SOx shall be demonstrated in the same manner as for the daily limits. Compliance with the annual emissions limits for PM_{10} and SO_2 from each gas turbine shall be calculated by multiplying turbine fuel usage times an emission factor determined by source testing of the turbine conducted in accordance with Part 26. The emission factor for each turbine shall be based on the average of the emissions rates observed during the 4 most recent source tests on that turbine (or, prior to the completion of 4 source tests on a turbine, on the average of the emission rates observed during all source tests on the turbine). (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~~Regulation 2-2-306)

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. To demonstrate compliance with this sulfur content limit, the owner/operator shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas, in addition to any monitoring requirements specified in Paragraph 29. (Basis: BACT for SO_2 and PM_{10}.)

    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. Natural gas consumption, fuel High Heating Value (HHV), and total fuel sulfur content
g. Turbine load in megawatts

h. Stack gas flow rate (DSCFM) calculated according to procedures in U.S. EPA Method 19
i. Exhaust gas temperature (°F)
j. Ammonia injection rate (lb/hr or moles/hr)
k. 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: Regulation 2-2-306~~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 26a 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 26b 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. Recordkeeping: 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 ~~7.3 tons of valid POC emission reduction credits and~~ ~~27.945~~23.35 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. Deleted September 2010. ~~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 not operate S-5 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets).

~~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 S-5 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))~~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 operate S-5 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)~~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. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
    a. Hours of operation for reliability-related activities (maintenance and testing).
    b. Hours of operation for emission testing to show compliance with emission limits.
    c. Hours of operation (emergency).
    d. For each emergency, the nature of the emergency condition.
    e. Fuel usage for each engine(s). (Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)~~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 4~~8~~5) 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~~Regulation 2-5)

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 43using 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~~ Regulation 2-5)

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 4~~3~~4. If three consecutive biennial source tests demonstrate that the annual emission rates for any of the compounds listed above calculated pursuant to part 4~~3~~5 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~~ Regulation 2-5)

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~~6,000 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: cumulative increase; Regulation 2-1-319)

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: cumulative increase; Regulation 2-1-319)

VI. Conclusion

The District has reviewed the Authority to Construct for the LECEF Phase II conversion project (Authority to Construct 8859) and has concluded that, with the revisions discussed herein, the Authority to Construct satisfies the requirements for a two-year extension pursuant to District Regulation 2-1-407.1.2, including meeting current District BACT and offset requirements under District Regulations 2-2-301, 2-2-302, and 2-2-303. Upon revision of the facility's California Energy Commission License to conform to the revised conditions discussed herein, the District will grant the applicant's Request for Renewal of this Authority to Construct.

Appendix A: Emissions Calculations

Emissions from the plant are calculated based on the BACT determinations made in Section III above.

Emission Factors

Emission Factors for Nitrogen Oxides (NO_x as NO_2)

The NO_x 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 NO_x, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8710 dscf/MMBTU)

= 0.00732 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) = **3.66 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) = **4.68 lb NO_2/hr**

Emission Factors for Carbon Monoxide (CO)

The CO emission factor used to calculate annual CO emissions from each turbine is based upon a maximum CO emission concentration of 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 CO, dry @ 0% O2

($7.04/10^6$)(1 lbmol/385.3 dscf)(28 lb CO/lbmol)(8710 dscf/MMBTU)

= 0.00446 lb CO/MMBTU

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

(0.00446 lb CO/MM BTU)(500 MM BTU/hr) = **2.23 lb CO/hr**

The 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) = **2.85 lb CO/hr**

Emission Factors for Precursor Organic Compounds (POC)

The POC emissions (as methane) from the turbine will be limited by permit condition to 1.0 ppmv, dry @ 15% O_2. This concentration is converted to a mass emission factor as follows:

(1.0 ppmvd)(20.95-0)/(20.95 – 15) = 3.52 ppmv, dry @ 0% O_2

($3.52/10^6$)(1 lbmol/385.3 dscf)(16 lb CH_4/lbmol)(8710 dscf/MMBTU)

= 0.00127 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:

(0.00126 lb POC/MM BTU)(500 MM BTU/hr) = **0.64 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) = **0.81 lb POC/hr**

Emission Factors for Sulfur Dioxide (SO_2)

The SO_2 emission factor used to calculate **annual SO_2 emissions** is based upon an expected average natural gas sulfur content of 0.25 grains per 100 scf and a higher heating value of 1020 BTU/scf.

The sulfur dioxide emission factor is calculated as follows:

(0.25 gr/100 scf)(10^6 BTU/MM BTU)(2 lb SO_2/lb S)(lb/7000 gr)(scf/1020 BTU)

= 0.00070 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:

(0.00070 lb SO_2/MM BTU)(500 MM BTU/hr) = **0.35 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:

(0.00070 lb SO_2/MM BTU)(639 MM BTU/hr) = **0.45 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 1050 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/1020 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) = **1.36 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) = **1.74 lb SO_2/hr**

Emission Factor for PM_{10}

A PM_{10} emission factor of 2.5 lb/hr was used to calculate emissions for the simple-cycle plant and for the initial analysis of the combined-cycle conversion project. Based on further analysis of source test results for similar aeroderivitive turbines, the District expects that emissions will most likely be below 2.2 lb/hour at all times. There is still some debate among equipment manufacturers and operators regarding whether this lower rate can be guaranteed at all times, but at the very least it is an appropriate number on which to base longer-term emissions estimates such as annual PM_{10} emissions rates.

Emission Factor for Ammonia (NH_3)

The ammonia (NH_3) mass emission rate from the turbines will be limited by permit condition to 5 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:

(5.0 ppmvd)(20.95-0)/(20.95 – 15) = 17.61 ppmv NO_x, dry @ 0% O2

(17.61/10^6)(1 lbmol/385.3 dscf)(17 lb NH_3/lbmol)(8710 dscf/MMBTU)

= 0.0068 lb NH_3/MMBtu

(0.0068 lb NH_3/MMBtu)(639 MMBtu/hr) = **4.34 lb/hr w/ duct firing**

(0.0068 lb NH_3/MMBtu)(500 MMBtu/hr) = **3.40 lb/hr w/ duct firing**

Maximum Emissions Summary

Maximum Hourly Emissions for Gas Turbines and HRSGs

Table A.1: Maximum Hourly Emission for Combined-Cycle Configuration (lb/hour-turbine-HRSG)					
	NO_x	**POC**	**PM_{10}**	**CO**	**SO_2**
Emissions Rate	4.68	0.81	2.2	2.85	1.79

The emissions listed are the maximum hourly emissions, excluding startup and shutdown.

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 two starts, followed by 20 hours of full load gas turbine operation with duct burner (DB) 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.

NO_2 = (2)(41 lb/event) + (40 lb/event) + (4.68 lb/hr)(20 hr full load w/DB firing)
= 175.6 lb/day/turbine/HRSG

CO = (2)(20 lb/event) + (2.85 lb/hr)(20 hr full load w/DB firing)

= 97.0 lb/day/turbine/HRSG

POC = (2)(2 lb/event) + (0.81 lb/hr)(20 hr full load w/DB firing)

= 20.2 lb/day/turbine/HRSG

PM_{10} = (2.2 lb/hr)(24 hr full load w/DB firing)

= 52.8 lb/day/turbine/HRSG

SO_2 = (1.79 lb/hr)(24 hr full load w/DB firing)

= 42.9 lb/day/turbine/HRSG

Table A.2: Maximum Daily Emission for Combined-Cycle Configuration (lb/day-turbine-HRSG)					
	NO_2	**POC**	**PM_{10}**	**CO**	**SO_2**
2 Starts and Full Load with Duct Burner Firing	175.6	20.2	52.8	97.0	42.9

Maximum 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:

- 6460 hours of full load operation per turbine per year @ 29°F without HRSG duct burner firing
- 1500 hours of full load operation with duct burner firing per turbine/HRSG per year @ 29°F
- 400 start-up operations per year per gas turbine

This represents an anticipated operating scenario for the facility. The actual operation of the facility will be determined and dictated by both Pacific Gas and Electric (PG&E) pursuant to the terms of a power purchase agreement (PPA) and by the California Independent System Operator (ISO) based on grid conditions and demand. Because LECEF is equipped with four combustion turbines, it will have the advantage that, as grid conditions dictate and electricity demand changes throughout the day, individual combustion turbine/HRSG units can be shut-down completely, as opposed to operating a larger unit, such as an F-class gas turbine, at reduced load.

The above anticipated operating scenario is based upon the expectation that, upon conversion from simple-cycle to combined-cycle operations, LECEF will be dispatched as an intermediate to baseload facility. According to public testimony filed by PG&E with the California Public Utilities Commission (CPUC) requesting approval of its PPA with LECEF, upon conversion, LECEF will be subject to and meet the emissions performance standard required by Senate Bill (SB) 1368, which precludes utilities from signing long-term contracts for facilities with high GHG emissions.[54] Under the emissions performance standard adopted by the CPUC pursuant to SB 1368, generating facilities intended to provide electricity at an annualized capacity factor of 60 percent or greater (*i.e.*, "baseload", according to SB 1368) must achieve the emissions standard of 1,100 pounds of greenhouse gases (measured as carbon dioxide-equivalents)(CO_2e) per megawatt-hour (MWh).[55] In its public testimony, PG&E describes the upgraded LECEF as "a dispatchable and operationally flexible resource" that will meet SB 1368's emissions performance standard[56] and support "PG&E's efforts to integrate renewal generation and enable overall reductions in GHG emissions in PG&E's portfolio."[57] Thus, information submitted by PG&E to the CPUC and by the applicant to the Air District indicates that LECEF 2 will be used to provide "shaping power", which will enable integration of renewable resources and, as a consequence of its location at a critical position within the grid, alleviate existing grid congestion.

In light of the foregoing anticipated operating scenario, the combined NO_x (as NO_2) and CO emissions from the turbines and HRSGs will be limited by permit condition to 94.1tons/year and

[54] Sen. Bill No. 1368, Stats. 2006 (2005-2006 Reg. Sess), ch. 598 § 8341(b)(4).

[55] CPUC, Adopted Interim Rules for Greenhouse Gas Emissions Performance Standards, R. 06-04-009, D.07-01-039 (Jan. 25, 2007).

[56] *See* Application of Pacific Gas and Electric Company for Approval of the Novation of the California Department of Water Resources Agreements Related to the Calpine Transaction, and Associated Cost Recovery, Prepared Testimony, Public Version, Oct. 30, 2009, Ch. 3, 3-9, 3-10.

[57] *Id.*, at 3-10.

53.4 tons/year, respectively. The accumulated mass emission totals for NO_x 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.

NO_x (as NO_2):

[(3.66 lb/hr)(6460 hr/yr) + (4.68 lb/hr)(1500 hr/yr) + (41 lb/startup)(400 startup/yr)](4 turbines)

= 188,254 lb NO_2/yr

= 94.1 ton/yr

POC:

[(0.64 lb/hr)(6460 hr/yr) + (0.81 lb/hr)(1500 hr/yr) + (2 lb/startup)(400 startup/yr)](4 turbines)

= 24,598 lb/yr

= 12.3 ton/yr

PM_{10}:

[(2.2 lb/hr)(6460 hr/yr) + (2.2 lb/hr)(1500 hr/yr) + (4.4 lb/startup)(400 startup/yr)](4 turbines)

= 77,088 lb/yr

= 38.5 ton/yr

CO:

[(2.23 lb/hr)(6460 hr/yr) + (2.85 lb/hr)(1500 hr/yr) + (20 lb/startup)(400 startup/yr) +

= 106,723 lb/yr

= 53.4 ton/yr

SO_2:

[(0.35 lb/hr)(6460 hr/yr) + (0.45 lb/hr)(1500 hr/yr) + (0.7 lb/startup)(400 startup/yr)](4 turbines)

= 12,864 lb/yr

= 6.43 ton/yr

NH_3:

[(3.4 lb/hr)(6460 hr/yr) + (4.34 lb/hr)(1500 hr/yr)](4 turbines)

= 113,896 lb/yr

= 56.94 ton/yr

Table A.3: Maximum Annual Emission for Combined-Cycle Configuration (ton/year for 4 turbine and HRSG trains)				
NO_2	**POC**	**PM_{10}**	**CO**	**SO_2**
94.1	12.3	38.5	53.4	6.43

Maximum Annual Emissions for Fire Pump Diesel Engine

Table A.4: 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]	4.43	0.04	0.046	0.165	0.093
ton/yr[b]	1.11	0.01	0.01	0.04	0.02

[a] Engine operation for discretionary purposes was limited to 45 minutes per day in the ATC that was issued in 2007. There is no basis for this limitation and it is therefore removed. A District Health Risk Analysis (See May 11, 2004 memorandum from Jane Lundquist to Dennis Jang) indicated that the levels of risk associated with the LECEF2 are acceptable for TBACT. The risk contribution from the firepump engine was based on 100 hours of annual operation allowed in the 2007 ATC for discretionary operation. This annual limitation is being reduced to 50 hours to comply with the current Stationery Diesel Engine ATCM (See Condition 19610, Part 39).

[b] Based on 500 hr/yr of operation on fuel with a maximum sulfur content of 0.05% and engine rating of 300 bhp based on EPA Guidance. *See* Memorandum, from John S. Seitz (Director, Office of Air Quality Planning and Standards, U.S. EPA), to U.S. EPA Regional Air Division Directors, Subject: "Calculating Potential to Emit (PTE) for Emergency Generators", September 6, 1995, at p. 3. ("The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions."). Calculation for annual emissions is based on non-discretionary hourly emissions multiplied by 500 hours per year.

Maximum Annual Emissions for Cooling Towers

Emissions for One Cell Cooling Tower

The LECEF is currently 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: 6,000 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} = (6,000 ppm)(35.4 lb/hr)/(10^6)
= 0.212 lb/hr
= 5.10 lb/day (24 hr/day operation)
= 1860 lb/yr (8,760 operating hours per year)
= 0.93 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.

Emissions for 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: 6,000 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} = (6,000 ppm)(182.65 lb/hr)/(10^6)
= 1.096 lb/hr
= 26.30 lb/day (24 hr/day operation)
= 9600 lb/yr (8,760 operating hours per year)
= 4.80 ton/yr

Maximum Annual Plant Emissions

Table A.5 summarizes the maximum facility criteria pollutant emissions from the new combined-cycle facility. The permit conditions will be amended for the lower annual emissions of POC and CO.

Table A.5
Maximum Annual Facility Emissions, Combined-Cycle Configuration (tons/yr)

	NO_x	POC	PM_{10}	CO	SO_2
Turbines and HRSGs	94.1	12.3	38.5	53.4	6.43
Fire Pump Diesel Engine	1.11	0.01	0.01	0.04	0.02
One-Cell Cooling Tower	0	0	0.93	0	0
Six-Cell Cooling Tower	0	0	4.80	0	0
Total	**95.21**	**12.31**	**44.24**	**53.44**	**6.45**