APPENDIX 5.1C

BACT Analysis

APPENDIX 5.1C

Evaluation of Best Available Control Technology

The LEC project is required to use best available control technology on the combustion turbine/HRSG, the auxiliary boiler, and the cooling tower for various pollutants, in accordance with the requirements of the federal PSD and the District new source review programs. The applicability of BACT requirements under PSD regulations is discussed in Section 5.1.7.1. For sources subject to PSD, BACT is defined in 40 CFR 52.21(j) as:

> "an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

The applicability of BACT requirements under District regulations is discussed in Section 5.1.7.3. The SJVAPCD defines BACT as:

> "the most stringent emission limitation or control technique of the following:

- Achieved in practice for such category and class of source;
- Contained in any State Implementation Plan approved by the Environmental Protection Agency for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or
- Contained in an applicable federal New Source Performance Standard; or
- Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source." [Rule 2201, Section 3.9]

The federal PSD BACT requirement is applicable for NOx and CO, while the District BACT requirement is applicable for all pollutants. The emission rates and control technologies determined to be BACT for this project are discussed in detail in the following sections. For the CTG/HRSG, separate determinations are provided for normal operation and startup/shutdown operation.

5.1C.1 BACT for the CTG/HRSG: Normal Operations

5.1C.1.1 NOx Emissions

5.1C.1.1.1 Achievable Controlled Levels and Available Control Options

The most recent NOx BACT listings for combined-cycle combustion turbines in this size range are summarized in Table 5.1C-1. The most stringent NOx limit in these recent BACT determinations is a 2.0 ppm[1] limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using DLN combustors and SCR. The Elk Hills project was given the option of using SCONOx instead of SCR, with a NOx limit of 2.5 ppm.

The SJVAPCD adopted Rule 4703 (Stationary Gas Turbines) to limit NOx emissions from these devices. Rule 4703 specifies an enhanced Tier II NOx emission limit of 3 ppmv @ 15% O_2 for natural gas-fired combustion gas turbines rated at no less than 10 MW and equipped with SCR (April 30, 2008 deadline).

SCONOx is a NOx reduction system produced by Goal Line Environmental Technologies. It is now distributed by EmeraChem as EMx. This system uses a single catalyst to oxidize both NOx and CO and then a regeneration system to convert the NO_2 to N_2 and water vapor. The system does not use ammonia as a reagent. The EMx process has been demonstrated in practice on much smaller gas turbines, including Redding Electric Utility's (REU) Unit 5, a 43-MW Alstom GTX100 combined-cycle gas turbine. While the technology has never been demonstrated on a gas turbine the size of the 7FA, the technology is considered by the manufacturer to be scalable.

The SCR system uses ammonia injection to reduce NOx emissions. SCR systems have been widely used in combined-cycle gas turbine applications of all sizes, including the 7FA and the larger H-class. The SCR process involves the injection of ammonia into the flue gas stream via an ammonia injection grid upstream of a reducing catalyst. The ammonia reacts with the NOx in the exhaust stream to form N_2 and water vapor. The catalyst does not require regeneration, but must be replaced periodically—approximately every 3 years.

Either SCR or SCONOx technology, in combination with dry low-NOx (DLN) combustion, will achieve a NOx emission level of 2.0 ppmvd@ 15% O_2.

5.1C.1.1.1.1 Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 10 ppmvd @ 15% O_2. A health risk screening analysis of the proposed project using air dispersion modeling showed the acute hazard index and a chronic hazard index each to be much less than 1, based on an ammonia slip limit of 10 ppmv @ 15% O_2. In accordance with the District's Integrated Air Toxics program and currently accepted practice, a hazard index below 1.0 is not considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

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[1] All turbine/HRSG exhaust emissions concentrations shown are corrected to 15% O2.

TABLE 5.1C-1
Recent NOx BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	NOx Limit	Averaging Prd	Control Method Used	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	2.0 ppmc	1 hour	DLN/SCR	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	2.0 ppmc	1 hour	DLN/SCR	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	2.0 ppmc	1 hour	DLN/SCR	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	2.0 ppmc	3 hours	DLN/SCR	April 2007	PSD permit
San Joaquin Valley Energy Center	EPA Region 9	2.0 ppmc	1 hour	DLN/SCR	August 2006	PSD permit
Mountainview Power	SCAQMD	2.0 ppmc	1 hour	DLN/SCR	2004	amendment
Pastoria Energy LLC	SJVAPCD	2.5 ppmc	1 hour	DLN/SCR	2004	PSD amendment
Magnolia Power Project	SCAQMD	2.0 ppmc	3 hours	DLN/SCR	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	2 hour	DLN/SCR	February 2004	SCAQMD website
PSO Southwestern Power Plant	Oklahoma	9.0 ppmc	--	DLN	February 2007	EPA RBLC
Rocky Mountain Energy Center	Colorado	3.0 ppmc	1 hour	DLN/SCR	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	2.0 ppmc	3 hours	DLN/SCR	August 2005	EPA RBLC
Wanapa Energy Center	Oregon	2.0 ppmc	3 hours	DLN/SCR	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	3.0 ppmc	annual	DLN/SCR	June 2005	EPA RBLC
Berrien Energy, LLC	Michigan	2.5 ppmc	24 hours	DLN/SCR	April 2005	EPA RBLC
Turner Energy Center[b]	Oregon	2.0 ppmc	1 hour	DLN/SCR	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. RBLC record indicates that project will not be built.

The ammonia emissions resulting from the use of SCR may have another environmental impact through their potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, the SJVAPCD has stated that because of high background levels of ammonia, the formation of ammonium nitrate and ammonium sulfate in the San Joaquin Valley air basin is limited by the formation of nitrates and sulfates and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the SJVAPCD.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of anhydrous ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident and is already being stored and used at the existing STIG #2 plant. As discussed in Section 2.0, the project will utilize the existing ammonia delivery system, which consists of an ammonia storage tank, spill containment basin, and refilling station with a spill containment basin and sump—new ammonia storage facilities will not be constructed as part of the proposed project. NCPA is already required to maintain a Risk Management Plan (RMP) and to implement a Risk Management Program to prevent accidental releases of ammonia. The RMP will be updated to include use of ammonia at the LEC (see Section 5.5 of the AFC). The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. Thus, the potential environmental impact due to anhydrous ammonia use at the LEC is minimal and does not justify the elimination of SCR as a control alternative.

Regeneration of the EMx catalyst is accomplished by passing hydrogen gas over an isolated catalyst module. The hydrogen gas is generated by reforming steam, so additional steam would be required beyond that for which the project is designed. This would require an increase in the size of the auxiliary boiler as well as an increase in expected boiler operation and emissions.

5.1C.1.1.1.2 Achieved in Practice Evaluation

While there are no formal "achieved in practice" criteria in the SJVAPCD, the SCAQMD has established formal criteria for determining when emission control technologies should be considered achieved in practice (AIP) for the purposes of BACT determinations. The criteria include the elements outlined below.

- Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guarantee must be available with the purchase of the control technology, as well as parts and service.
- Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50% design

capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

- Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Each of these criteria is discussed separately below for SCR and for EMx.

SCR Technology – SCR has been achieved in practice at numerous combustion turbine installations throughout the world. There are several utility-scale combined cycle projects that limit NOx emissions to 2.0 ppm, including the Mountainview Power Plant in San Bernardino County; the Inland Empire Energy Center in Riverside County; and the Cosumnes Power Plant in Sacramento County. An evaluation of the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.0 ppm and lower) using SCR technology is summarized below.

- Commercial Availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 2 ppm. Consequently, this criterion is satisfied.
- Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 2.0 ppm permit limit during extended, routine operations at several commercial power plants. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.
- Effectiveness: SCR technology has been demonstrated to achieve NOx levels of 2.0 ppm and less. Short-term excursions have resulted in NOx concentrations above the permitted level of 2.0 ppm; however, these excursions have not been associated with diminished effectiveness of the SCR system. Rather, these excursions have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed.
- Conclusion: SCR technology capable of achieving NOx levels of 2.0 ppm is considered to be achieved in practice. The proposed permit limits for the proposed Lodi Energy Center CTG/HRSG include a NOx limit of 2.0 ppm. This proposed limit is consistent with the available data.

EMx Technology – EMx has been demonstrated in service in five applications: the Sunlaw Federal cogeneration plant, the Wyeth BioPharma cogeneration facility, the Montefiore Medical Center cogeneration, the University of California San Diego facility, and the Redding Power Plant. The combustion turbines at these facilities are much smaller than for the proposed LEC turbine. The largest installation of the EMx system is at the Redding Power Plant. The Redding Power Plant currently consists of a single combined cycle 43 MWe Alstom GTX100 combustion turbine with a permitted NOx emission rate of 2.5 ppm. There is a second 43 MWe unit under construction at the Redding Power Plant, but that unit has not begun operation.

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[2] indicates a mean NOx level for the unit of less than 1.0 ppm during the period from 2002 to 2007. After the first year of operation, Unit #5 at the REU power plant has experienced only a few hours of non-compliance per year (fewer than 0.1% of the annual operating hours exceed the NOx permit limit of 2.5 ppm). At the lower NOx limit of 2.0 ppm that will be required for the proposed LEC, the CEM data show that the number of non-compliant hours increases to approximately 0.2% of the annual operating hours. The experience at the City of Redding Plant indicates the ability of the EMx system to control NOx emissions to levels of 2.0 ppm and less.

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.0 ppm) using EMx technology.

- Commercial availability: While a proposal has not been sought, presumably EmeraChem Power would offer standard commercial guarantees for the proposed LEC. Consequently, this criterion is expected to be satisfied.
- Reliability: As discussed above, based on a review of the CEM data for REU Unit #5 the EMx system complied with the 2.0 ppm NOx permit limit but with a few hours each year of excess emissions (approximately 3% of annual operating hours following the first year, and approximately 2% following the second year, dropping to approximately 0.1% after 4 years). This level of performance was also associated with some significant operating and reliability issues. According to a June 23, 2005 letter from the Shasta County Air Quality Management District3, repairs to the EMx system began shortly after initial startup and have continued during several years of operation. Redesign of the EMx system was required due to a problem with the reformer reactor combustion production unit that led to sulfur poisoning of the catalyst. In addition, the EMx system catalyst washings had to occur at a frequency several times higher than anticipated during the first three years of operation, which has resulted in substantial downtime of the combustion turbine. Since the REU installation is the most representative of all of the EMx-equipped combustion turbine facilities for comparison to the proposed LEC, the problems encountered at REU bring into question the reliability of the EMx system for the proposed project.
- Effectiveness: The EMx system at the REU power plant has recently been able to demonstrate compliance with a NOx level of 2.0 ppm. However, there are no EMx-equipped facilities of a size similar to that of the proposed LEC. Consequently, due to the lack of actual performance data, there is some question regarding the effectiveness of the EMx systems on large combustion turbine projects.
- Conclusion: EMx systems are capable of achieving NOx levels of 2.0 ppm and less. However, the operating history at the Redding Power Plant does not support a conclusion that this technology is achieved in practice based on South Coast AQMD guidelines, due mainly to reliability issues.

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[2] Available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results

[3] Letter dated June 23, 2005, from Shasta County Air Quality Management District to the Redding Electric Utility regarding Unit 5 demonstration of compliance with its NOx permit limit.

5.1C.1.1.1.3 Conclusion

Because both SCR and EMx are expected to achieve the proposed BACT NO_x emission limit of 2.0 ppmvd @ 15% O_2 averaged over one hour and neither will cause significant energy, economic, or environmental impacts, neither can be eliminated as viable control alternatives. The concern remains regarding the long-term effectiveness of EMx as a control technology as the technology has not been demonstrated on the turbine used in this project. In addition, LEC is utilizing the new Rapid Response startup process for this turbine (discussed in more detail below) so will already be challenged with integrating a new technology, with the potential for much larger emissions reductions. For these reasons, and because SCR is already in use at the facility, SCR has been selected as the NOx control technology to be used for the LEC.

5.1C.1.1.1.4 Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the NOx BACT determination of 2.0 ppm @ 15% O_2 on a 1-hour average basis made for recently permitted combined cycle turbine projects in SJVAPCD and elsewhere reflects the most stringent achievable NOx emission limit. The LEC facility will be designed to meet a NOx level of 2.0 ppmv @ 15% O_2 on a 1-hour average basis using SCR.

5.1C.1.2 CO Emissions

5.1C.1.2.1 Achievable Controlled Levels and Available Control Options

Oxidation catalyst technology is commonly used to control CO emissions.

The CARB's BACT guidance document for electric generating units rated at greater than 50 MW[4] indicates that BACT for the control of CO emissions from stationary gas turbines used for combined-cycle and cogeneration power plants is 6 ppmvd @ 15% O_2.

The BAAQMD's BACT guidelines specify that, for natural gas-fired combined-cycle gas turbines larger than 40 MW, a CO limit of 4 ppmv @ 15% O2 has been "achieved in practice."

The SJVAPCD's BACT guidelines contained determinations for gas turbines larger than 50 MW with uniform load and with heat recovery. The SJVAPCD concluded that a CO exhaust concentration of 6 ppmv @ 15% O_2 constituted BACT that had been achieved in practice, while 4.0 ppmv @ 15% O_2 is considered technologically feasible.

A summary of recent CO BACT determinations for large, combined-cycle gas turbines is shown in Table 5.1C-2. Similar facilities using oxidation catalysts have been permitted at between 2.0 and 4.0 ppm CO. CO emission limits for projects in the SCAQMD may be considered to go beyond BACT because (1) the District is a nonattainment area for CO, so more stringent control requirements apply; and (2) applicants in the SCAQMD are required to provide offsets for CO, so there is additional incentive to reduce CO emission levels beyond BACT to minimize offset requirements. We are not aware of any available in-use data that shows whether compliance with the 2.0 ppm limits has been demonstrated in practice.

[4] CARB, "Guidance for Power Plant Siting and Best Available Control Technology," July 1999.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the CO standards that govern existing natural gas-fired simple cycle combustion gas turbines. Of the five prohibitory rules reviewed, the SJVAPCD prohibitory rule for combustion gas turbines is the only one that includes an emission limit for CO (200 ppmv @ 15% O_2). The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a CO limit.

5.1C.1.2.1.1 Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. The proposed CO emission limit of 3 ppmvd @ 15% O_2 on a 3-hour average basis is more stringent than the level currently considered BACT, but is expected to be achievable in practice.

5.1C.1.3 VOC Emissions

5.1C.1.3.1 Achievable Controlled Levels and Available Control Options

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex compounds and toxic compounds formed in the combustion process. Therefore, use of an oxidation catalyst is generally considered BACT for VOC.

The CARB's BACT guidance document for electric generating units rated at greater than 50 MW[5] indicates that BACT for the control of POC emissions for combined-cycle and cogeneration power plants is 2 ppmvd @ 15% O_2.

The BAAQMD's BACT guidelines specify that, for natural gas-fired combined cycle combustion gas turbines larger than 40 MW, a VOC limit of 2 ppmvd @ 15% O_2 has been "achieved in practice."

The SJVAPCD's BACT guidelines contained a determination for gas turbines rated at larger than 50 MW with uniform load and with heat recovery. The SJVAPCD concluded that a VOC exhaust concentration of 2.0 ppmvd @ 15% O_2 constituted BACT that had been achieved in practice, while 1.5 ppmvd @ 15% O_2 is considered technologically feasible.

The SCAQMD database contains BACT determinations for VOC emissions from two natural gas-fired combined cycle combustion gas turbines at 2.0 ppmvd @ 15% O_2.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the VOC standards that govern existing natural gas-fired simple cycle combustion gas turbines. None of the prohibitory rules for combustion gas turbines specify an emission limit for VOC. The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a VOC limit.

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5 Ibid, Table I-1.

TABLE 5.1C-2

ReCent CO BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	CO Limit	Averaging Prd	Control Method Used	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	4.0 ppmc	3 hours	oxidation catalyst	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	3.0 ppmc	3 hours	oxidation catalyst	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	4.0 ppmc	3 hours	oxidation catalyst	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	4.0 ppmc	3 hours	oxidation catalyst	April 2007	PSD permit
San Joaquin Valley Energy Center	EPA Region 9	4.0 ppmc	1 hour	oxidation catalyst	August 2006	PSD permit
Pastoria Energy LLC	SJVAPCD	9.0 ppmc	3 hours	oxidation catalyst	2004	PSD amendment
Magnolia Power Project	SCAQMD	2.0 ppmc	1 hour	oxidation catalyst	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	3 hour	oxidation catalyst	February 2004	SCAQMD website
PSO Southwestern Power Plant	Oklahoma	25 ppmc	--	oxidation catalyst	February 2007	EPA RBLC
Rocky Mountain Energy Center	Colorado	3.0 ppmc	--	oxidation catalyst	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	3.5 ppmc	3 hours	oxidation catalyst	August 2005	EPA RBLC
Wanapa Energy Center	Oregon	2.0 ppmc	3 hours	oxidation catalyst	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	4.0 ppmc[b]	annual	oxidation catalyst	June 2005	EPA RBLC
Berrien Energy, LLC	Michigan	2.0 ppmc	3 hours	oxidation catalyst	April 2005	EPA RBLC
Turner Energy Center[c]	Oregon	2.0 ppmc / 3.0 ppmc	1 hour	oxidation catalyst	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Separate CO limit set for duct burners; this limit is for turbines only.

c. RBLC record indicates that project will not be built.

A summary of recent VOC BACT determinations for large, combined-cycle gas turbines is shown in Table 5.1C-3. Similar facilities using oxidation catalysts have been permitted at between 1.4 and 2.0 ppm VOC. Although several facilities are shown as having been permitted below these levels, compliance with these 1.0 ppm limits has not been achieved in practice because neither the Blythe II nor the Turner plants has been constructed or operated. Further, the Crescent City limit of 1.1 ppm is not comparable to the limits imposed for the other plants cited because it is an annual average limit and not a short-term limit.

5.1C.1.3.1.1 Conclusions

BACT must be at least as stringent as the most stringent achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. Based upon the results of this analysis, the VOC emission limits of 1.4 and 2.0 ppmv @ 15% O_2 are considered to be BACT for the proposed project.

5.1C.1.4 PM_{10}/$PM_{2.5}$ Emissions

5.1C.1.4.1 Achievable Controlled Levels and Available Control Options

PM emissions from natural gas-fired turbines and HRSGs primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean burning pipeline quality natural gas with low sulfur content.

The CARB BACT Clearinghouse, as well as the BAAQMD and SJVAPCD BACT guidelines, identify the use of natural gas as the primary fuel as “achieved in practice” for the control of PM_{10} for combustion gas turbines. The SJVAPCD also requires the use of an air inlet filter cooler and a lube oil vent coalescer to remove ambient particulate matter from the inlet air and to minimize the formation of lube oil mists.

The CARB’s BACT guidance document for stationary gas turbines used for combined-cycle and cogeneration power plant configurations[6] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. Subpart KKKK does not regulate PM_{10} emissions.

Published prohibitory rules from the District, SCAQMD, SJVAPCD, SMAQMD, and SDCAPCD were reviewed to identify the PM_{10} standards that govern natural gas-fired combustion gas turbines. These prohibitory rules do not regulate PM_{10} emissions. The applicable NSPS (40 CFR 60 Subpart KKKK) limits SOx emissions to 0.56 lb/MWh, well above permitted limits for natural gas-fired turbines.

Recent PM_{10} BACT determinations for similarly-sized gas turbines/HRSGs are summarized in Table 5.1C-4.

6 Ibid, Table I-2.

TABLE 5.1C-3
Recent VOC BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	VOC Limit	Averaging Prd	Duct Fired?	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	2.0 ppmc	3 hours	yes	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	2.0 ppmc	1 hour	yes	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	2.0 ppmc	3 hours	yes	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	1.0 ppmc	3 hours	yes	December 2005	CEC website
Magnolia Power Project	SCAQMD	2.0 ppmc	1 hour	yes	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	1 hour	yes	February 2004	SCAQMD website
Rocky Mountain Energy Center	Colorado	0.0029 lb/MMBtu	--	unknown	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	4.0 ppmc	3 hours	yes	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	1.1 ppmc	annual	no[b]	June 2005	EPA RBLC
Turner Energy Center[c]	Oregon	1.0 ppmc	3 hours	yes	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Separate VOC limit set for duct burners; this limit is for turbines only.

c. RBLC record indicates that project will not be built.

5.1C.1.4.1.1 Conclusions

Based upon the results of this analysis, the SJVAPCD BACT guideline reflects the most stringent PM_{10} emission limit. The District established a requirement for the use of natural gas as the primary fuel to control PM_{10} emissions from combustion gas turbines. Therefore, the use of natural gas as the primary fuel source constitutes BACT for PM_{10} emissions from combustion gas turbines. Through the use of natural gas, the turbine is expected to be able to meet the proposed emission limit of 9.0 lb/hr without duct firing and 11.0 lb/hr with duct firing. These limits are consistent with or lower than the limits shown in the summary table, with the exception of the Blythe II project. Since the Blythe II project has not yet been constructed or operated and no performance data are available, this permit limit is not considered achieved in practice.

5.1C.1.5 SOx Emissions

5.1C.1.5.1 Achievable Controlled Levels and Available Control Options

The CARB BACT Clearinghouse, as well as the BAAQMD and SJVAPCD BACT guidelines, identifies the use of PUC-quality natural gas or natural gas with a limit on the sulfur content (i.e., 1 grain/100 scf) as the primary fuel as “achieved in practice” for the control of SOx for combustion gas turbines. The two most recent BACT determinations in the SCAQMD did not indicate BACT for SOx.

5.1C.1.5.1.1 Federal NSPS

Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. A combustion gas turbine is subject to a SO_2 emission limit of 0.56 lb/MWh.

5.1C.1.5.1.2 District Prohibitory Rules

Published prohibitory rules from the BAAQMD, SJVAPCD, and SCAQMD were reviewed to identify the SO_2 standards that govern existing gas turbines.

- BAAQMD Rule 9-9 (Nitrogen Oxides from Stationary Gas Turbines) is the BAAQMD’s only prohibitory rule that specifically addresses gas turbines but does not limit SO2 emissions. The BAAQMD adopted Rule 9-1 (Sulfur Dioxide) to limit SO2 emissions from all sources. Rule 9-1 prohibits SO2 emissions in excess of 300 ppm. No other BAAQMD Rule or Regulation contains a relevant prohibitory rule regulating either the sulfur content in the fuel or the emission of SO2 from gas turbines.
- SJVAPCD Rule 4703 (Stationary Gas Turbines) is the SJVAPCD’s only prohibitory rule that specifically addresses gas turbines but does not limit SO2 emissions. The SJVAPCD adopted Rule 4301 (Fuel Burning Equipment) to limit SO2 emissions from these devices. Rule 4301 specifies a SO2 emission limit of 200 pounds per hour. The SJVAPCD also adopted Rule 4801 (Sulfur Compounds) to limit emissions of sulfur compounds. Rule 4801 specifies a SO2 emission limit of 0.2%, or 2,000 ppm.
- SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) is the SCAQMD’s only prohibitory rule that specifically addresses gas turbines; however, it does not limit SO2 emissions. The SCAQMD adopted Rule 431.1 (Sulfur Content of Gaseous Fuels) to reduce SOx emissions from the burning of gaseous fuels in stationary equipment. Rule 431.1 specifies a sulfur limit of 16 grains/100 scf (as H2S) in natural gas sold within the SCAQMD. The SCAQMD also adopted Rule 407 (Liquid and Gaseous Air Contaminants) to limit SO2 emissions from all sources. Rule 407 specifies an emission limit of 2,000 ppm for sulfur compounds (calculated as SO2).

TABLE 5.1C-4
Recent PM_{10} BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	PM_{10} Limit, no duct firing	PM_{10} Limit, with duct firing	Date Permit Issued	Source
Colusa Generating Station	EPA Region 9	12.9 lb/hr	20.0 lb/hr	May 2008	CEC final decision
Russell City Energy Center	BAAQMD	8.6 lb/hr	11.6 lb/hr	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)	MDAQMD		6.0 lb/hr[a]	December 2005	CEC website
Magnolia Power Project	SCAQMD	--	11.0 lb/hr	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	--	11.0 lb/hr	February 2004	SCAQMD website
Rocky Mountain Energy Center	Colorado	--	0.0074 lb/MMBtu	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	--	0.011 lb/MMBtu	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	29.6 lb/hr	0.01 lb/MMBtu[b]	June 2005	EPA RBLC
Turner Energy Center[c]	Oregon	--	18 lb/hr	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Annual limit.

c. RBLC record indicates that project will not be built.

- SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) is the SCAQMD's only prohibitory rule that specifically addresses gas turbines; however, it does not limit SO2 emissions. The SCAQMD adopted Rule 431.1 (Sulfur Content of Gaseous Fuels) to reduce SOx emissions from the burning of gaseous fuels in stationary equipment. Rule 431.1 specifies a sulfur limit of 16 grains/100 scf (as H2S) in natural gas sold within the SCAQMD. The SCAQMD also adopted Rule 407 (Liquid and Gaseous Air Contaminants) to limit SO2 emissions from all sources. Rule 407 specifies an emission limit of 2,000 ppm for sulfur compounds (calculated as SO2).

5.1C.1.5.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the CARB database and BAAQMD and SJVAPCD BACT guidelines reflect the most stringent SOx emission limit. These sources established a requirement for the use of natural gas as the primary fuel to control SOx emissions from combustion gas turbines. Therefore, the use of natural gas as the primary fuel source constitutes BACT for SOx emissions from the gas turbine/HRSG.

5.1C.2 BACT for the CTG/HRSG: Startup/Shutdown

Startup and shutdown periods are a normal part of the operation of combined cycle power plants such as LEC. BACT must also be applied during the startup and shutdown periods of gas turbine/HRSG operation. The BACT limits discussed in the previous section apply to steady-state operation, when the turbine, HRSG, and steam turbine have reached stable operations and the emission control systems are fully operational.

During gas turbine startup, there are equipment and process requirements that must be met in sequential order to protect the equipment. Many of these require holding the gas turbine at low loads, where operation is inefficient and emissions are relatively high, to allow the HRSG to warm up and steam turbine seals and condenser vacuum to be established. At low turbine loads, the combustors are not yet operating in lean pre-mix mode so turbine-out NOx emission rates are also high during startup. In addition, incomplete combustion at low loads results in higher CO and VOC emission rates. Further, the post-combustion controls that are used to achieve additional emissions reductions (SCR and oxidation catalyst) require specific exhaust temperature ranges to be fully effective. The use of SCR to control NOx is not technically feasible when the surface of the SCR catalyst is below the manufacturer's recommended operating range. When surface temperatures are low, ammonia will not react completely with the NOx, resulting in excess NOx emissions or excess ammonia slip. The oxidation catalyst is not effective at controlling CO emissions when exhaust temperature is outside the optimal temperature range. Therefore, the BACT determinations for NOx, CO, and VOC during normal, steady-state operation are not applicable during startup and shutdown. However, since SO_2 and PM_{10} emissions result from the characteristics of the fuel burned and do not rely on any emissions control system, the BACT determinations for SO_2 and PM_{10} emissions are applicable during startup and shutdown as well.

Because NOx, CO, and VOC emissions during startup and shutdown are not effectively reduced by combustion controls or add-on control devices, the emission rates themselves cannot be effectively reduced. Therefore, the pound per hour NOx, CO, and VOC limits proposed by the applicant for startup and shutdown periods represent achievable emissions limits based on experience with other, similar turbine projects and are considered BACT for startup and shutdown.

Since the emission rates cannot be reduced, startup emissions must be addressed by minimizing the amount of time the gas turbine and HRSG spend in startup. Efforts have been made by turbine and HRSG manufacturers to develop ways of reducing the time required to ramp up the CTG load to where the DLN combustors will be effective and exhaust temperatures will allow the control devices to be effective. LEC is proposing to utilize a new Rapid Response process for this project. Rapid Response includes the following project features:

- HRSG design: The HRSG will be designed to optimize heat transfer to the tubes, which will allow the HRSG to heat up more quickly. This will reduce gas turbine hold time at low load, especially during cold startups.
- Auxiliary boiler: The proposed project includes an auxiliary steam boiler that will provide steam during startup. The auxiliary boiler steam will preheat the CTG fuel and provide steam turbine sealing steam prior to CTG startup, thereby allowing the condenser vacuum to be established and the condenser to be in a condition ready to accept steam earlier in the startup cycle.

Both of these project design features are expected to reduce hold times for the gas turbine and therefore to allow the gas turbine/HRSG to reduce startup times, especially for cold and warm startups. Because this Rapid Response process has not yet been demonstrated on an operating gas turbine plant, LEC cannot assume the risk that the process will not operate as advertised by GE. Therefore, the NOx, CO, and VOC emissions limits proposed for the project assume that, as a worst case, the Rapid Response process does not allow a significant reduction in startup times.

In summary, LEC is proposing to go beyond BACT for startup and shutdown emissions by installing the Rapid Response system, but the applicant is not taking credit for the expected effectiveness of the Rapid Response system in reducing startup emissions.

5.1C.3 BACT for the Auxiliary Boiler

5.1C.3.1 NOx Emissions

5.1C.3.1.1 Achievable Controlled Levels and Available Control Options

NOx is formed during combustion through two mechanisms: (1) thermal NOx, which is the oxidation of elemental nitrogen in combustion air; and (2) fuel NOx, which is the oxidation of fuel-bound nitrogen. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NOx emissions in natural gas-fired equipment is minimal and thermal NOx is the chief source of NOx emissions. Thermal NOx formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

There are two basic means of controlling NOx emissions from boilers: combustion controls and post-combustion controls. Combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Combustion control technologies for this type of boiler application include low-NOx burners, flue gas recirculation and staged combustion. Post-combustion controls include SCR and selective non-catalytic reduction (SNCR). These are discussed below in order of most effective to least effective.

Selective Catalytic Reduction. The effectiveness of an SCR system requires the catalyst, and thus the treated exhaust stream, to be within a certain temperature range for the NOx reduction reaction to take place. The auxiliary boiler will be operated to support the Rapid Response turbine startup process and will be operated only up to 468 hours per year. The boiler is designed to provide 45,000 lb/hr of steam, with a minimum load of approximately 20,000 lb/hr to provide steam for steam turbine seals and sparging and the remaining 25,000 lb/hr for fuel gas heating. The majority of boiler operations are expected to be at low load, where the exhaust gas temperature is expected to be below the minimum needed for effective SCR control. While the boiler will operate at full load periodically, the length of time at which it will operate is expected to be so short that the SCR system could rarely, if ever, be used effectively. Therefore, this technology is not considered technically feasible for the auxiliary boiler in this application.

Selective Noncatalytic Reduction (SNCR). SNCR involves injection of ammonia or urea with proprietary conditions into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200 to 2000°F. The exhaust temperature for the proposed auxiliary boiler is 375°F, well below the minimum SNCR operating temperature. Therefore, SNCR is not technically feasible for this application.

Ultra-Low NOx Burners with Flue Gas Recirculation (FGR). Low-NOx burners with FGR are commonly used on industrial-sized package boilers such as the LEC auxiliary boiler. These burners minimize the formation of thermal NOx and FGR reduces the oxygen in the combustion zone to further reduce NOx formation. Ultra-low NOx burners with FGR can achieve NOx emission rates of 7 to 9 ppmvd @ 3% O_2 without post-combustion controls. A 9 ppm emission rate was recently accepted as BACT for the Colusa Generating Station auxiliary boiler and was considered the lowest technologically feasible emission rate for that particular application. A summary of the permitted emissions limits for other, similar boilers is provided in Table 5.1C-5 below.

5.1C.3.1.1.1 District BACT Determinations

The SJVAPCD's BACT determination for boilers in this size range with variable loads shows that less than 15 ppmc is considered achieved in practice while 9 ppm is considered technically feasible.

The BAAQMD has determined that 9 ppmc is achieved in practice while 7 ppmc is considered technologically feasible. However, the BAAQMD BACT guideline indicates that SCR is needed to achieve 7 ppmc, and, as discussed above, SCR is not feasible for this application.

5.1C.3.1.1.2 District Prohibitory Rules

The SJVAPCD is proposing to adopt more stringent boiler NOx control rules in the near future as part of its ozone and $PM_{2.5}$ attainment strategies. Rule 4306 would require natural gas-fired boilers of this size range and limited annual fuel use to achieve a NOx limit of 30 ppmvd @ 3% O_2. Proposed new Rule 4320 will be applicable to the proposed auxiliary boiler and will require compliance with a NOx limit of 7 ppmvd @ 3% O_2. NCPA has obtained an emissions guarantee of 7 ppm without SCR, so the new auxiliary boiler will comply with the proposed NOx limit in the new prohibitory rule.

5.1C.3.1.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the proposed 7 ppm NOx limit represents BACT for this application.

5.1C.3.2 VOC Emissions

5.1C.3.2.1 Achievable Controlled Levels and Available Control Options

VOC emissions during natural gas combustion result from incomplete combustion of the fuel gas. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Since those practices tend to increase NOx emissions, the effectiveness of the NOx control system may affect the ability of the boiler to achieve low VOC emission rates.

5.1C.3.2.1.1 District BACT Determinations

The SJVAPCD's BACT determination for boilers in this size range with variable loads shows that the use of natural gas fuel is considered to be BACT for VOCs.

The BAAQMD has determined that BACT for boilers in this size range is the use of good combustion practices for VOC control.

5.1C.3.2.1.2 District Prohibitory Rules

SJVAPCD draft Rule 4320 does not contain a VOC limit.

5.1C.3.2.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the proposed 10 ppm VOC limit represents BACT for this application. The proposed limit is expected to be achievable through the use of good combustion practices.

5.1C.3.3 SO_2 and PM_{10} Emissions

5.1C.3.3.1 Achievable Controlled Levels and Available Control Options

SO_2 and PM_{10} emissions from natural gas combustion result from sulfur and other impurities in the fuel. Emissions of these pollutants will be minimized through the use of low sulfur pipeline quality natural gas. There are no add-on control technologies that are effective in reducing SO_2 and PM_{10} emissions from naturally low-emitting natural gas-fired boilers.

TABLE 5.1C-5
Recent NOx and CO BACT Determinations for Medium-Sized Auxiliary Boilers

Facility	District/State	Heat Input Rating (MMBtu/hr HHV)	NOx Limit	CO Limit	Date Permit Issued	Source
Colusa Generating Station	EPA Region 9	44	9	50	May 2008	CEC final decision
Genentech	BAAQMD	97	9	50	September 2005	CARB BACT Clearinghouse
Medimmune, Inc	Maryland	29.4	9	n/a	January 2008	RBLC # MD-0037
CPV Warren	Virginia	97	0.011 lb/MMBtu [a]	0.036 lb/MMBtu[c]	January 2008	RBLC # VA-0308
Minnesota Steel Industries	Minnesota	99	0.035 lb/MMBtu[b]	0.08 lb/MMBtu[d]	September 2007	RBLC # MN-0070
Thyssenkrupp Steel and Stainless USA, LLC	Alabama	64.9	0.035 lb/MMBtu[b]	0.040 lb/MMBtu[c]	August 2007	RBLC # AL-0230
Daimler Chrysler Corporation	Ohio	20.4	0.0350 lb/MMBtu[b]	0.0830 lb/MMBtu[d]	May 2007	RBLC # OH-0309

Notes:

a. Equivalent to approximately 9 ppmc NOx.

b. RBLC record shows 0.0035 lb/MMBtu, but based on rated heat input and hourly limit, this is believed to be a typographical error. This is equivalent to approximately 27 ppmc NOx.

c. Equivalent to approximately 50 ppmc CO.

d. Equivalent to approximately 100 ppmc CO.

5.1C.3.3.1.1 District BACT Determinations

The SJVAPCD and BAAQMD BACT guidelines both indicate that the use of natural gas fuel is considered BACT for boilers.

5.1C.3.3.1.2 Conclusions

Use of pipeline quality natural gas is considered BACT for this boiler application. The proposed emissions limitations are expected to be achievable with natural gas firing.