California Environmental Protection Agency
AIR RESOURCES BOARD

Guidance for Power Plant Siting and Best Available Control Technology

As Approved by the Air Resources Board on July 22, 1999

Stationary Source Division
Issued September 1999

State of California
AIR RESOURCES BOARD

Resolution 99-31

July 22, 1999

Agenda Item No.: 99-6-2

WHEREAS, section 39500 of the California Health and Safety Code (Health and Safety Code) declares that the Air Resources Board ("ARB" or "Board") shall coordinate, encourage, and review the efforts of all levels of government as they affect air quality;

WHEREAS, sections 39600 and 39605 of the Health and Safety Code authorize the Board to act as necessary to execute the powers and duties granted to and imposed upon the Board and to provide assistance to the local air pollution control and air quality management districts (districts);

WHEREAS, sections 25000 *et seq.* of the California Public Resources Code (Public Resources Code) grant the State Energy Resources Conservation and Development Commission (California Energy Commission) with exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts or larger;

WHEREAS, section 25506 of the Public Resources Code states that the California Energy Commission shall request the appropriate local, regional, state, and federal agencies to make comments and recommendations regarding the design, operation, and location of thermal electric power plants, in relation to environmental quality, public health and safety, and other factors on which they may have expertise;

WHEREAS, Assembly Bill 1890 (Chapter 854, Statutes of 1996) restructured the electric utility industry in California to create a competitive, open market, resulting in an increase in the number of proposed and anticipated thermal electric power plants that will be significant sources of air pollutant emissions;

WHEREAS, Public Resources Code sections 25000 *et seq.* and California Energy Commission regulations require thermal electric power plants (projects) to be constructed and operated in compliance with applicable federal, State, and local air pollution requirements and with the California Environmental Quality Act, and require project applicants to demonstrate such compliance during the California Energy Commission's site certification process;

WHEREAS, the Board developed the Guidance for Power Plant Siting and Best Available Control Technology to promote compliance with all applicable laws, ordinances, regulations, and standards;

WHEREAS, the Guidance for Power Plant Siting and Best Available Control Technology proposed by ARB staff would establish ARB's position on air permitting issues related to the siting of thermal electric power plants;

WHEREAS, current emission measurement source test protocols have not kept pace with advances in emission control technology, although instrumentation is available to measure emissions at and below present best available control technology levels;

WHEREAS, emissions from power plants may be a significant source of greenhouse gas emissions;

WHEREAS, the Board has held a duly noticed public meeting to consider approval of the Guidance for Power Plant Siting and Best Available Control Technology and has heard and considered the comments of interested parties;

WHEREAS, the Board finds that:

The Guidance for Power Plant Siting and Best Available Control Technology is intended to provide assistance to districts and promote consistency in review as the districts participate in the California Energy Commission thermal electric power plant siting process;

The Guidance for Power Plant Siting and Best Available Control Technology establishes appropriate ARB guidance, perspective, and recommendations regarding best available control technology, emission offsets, ambient air quality impact analysis, health risk assessment, and other permitting considerations related to the permitting of thermal electric power plants;

It is necessary and appropriate for staff to evaluate the need for modifications to the Guidance for Power Plant Siting and Best Available Control Technology on a periodic basis for the purpose of modifying recommended best available control technology emission levels, to make other related modifications, and to incorporate changes in policy;

It is necessary and appropriate for staff, after the Board votes on this agenda item 99-6-2, to identify problems with current source test methods and develop procedures to accurately and consistently measure power plant emissions at low levels;

It is necessary and appropriate for staff, after the Board votes on this agenda item 99-6-2, to work with affected stakeholders to provide a perspective on carbon dioxide emissions from power plants; and

WHEREAS, the Board finds that approval of the Guidance for Power Plant Siting and Best Available Control Technology should promote the use of enforceable best available control technology limitations on new power plants sited in California.

NOW, THEREFORE, BE IT RESOLVED that the Board hereby approves the Guidance for Power Plant Siting and Best Available Control Technology, as proposed by staff and noticed on June 23, 1999 (identified as Attachment A to this Resolution), with specific textual amendments thereto in response to the Board's directives during today's hearing on this item.

BE IT FURTHER RESOLVED that the Board does not intend the Guidance for Power Plant Siting and Best Available Control Technology to be construed to mean that power plants sited in California need not comply with the federal Clean Air Act or California's State Implementation Plan.

BE IT FURTHER RESOLVED that the Guidance for Power Plant Siting and Best Available Control Technology is considered contemporaneous with its date of publication and is subject to modification as changes in policy, operational data, advances in technology, and any other relevant information dictates.

BE IT FURTHER RESOLVED that the Board delegates authority to the Executive Officer to update and approve modifications to the Guidance for Power Plant Siting and Best Available Control Technology.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to evaluate the need to update and modify the Guidance for Power Plant Siting and Best Available Control Technology, and to report modifications or lack thereof to the Board within six months of July 22, 1999, and thereafter as the Executive Officer deems appropriate. This report shall also include a discussion of carbon dioxide emissions from power plants.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to distribute the Guidance for Power Plant Siting and Best Available Control Technology, approved herein and as subsequently modified, to the districts for use in siting new thermal electric power plants.

I hereby certify that the above is a true and correct copy of Resolution 99-31, as adopted by the Air Resources Board.

_____

Pat Hutchens, Clerk of the Board

Resolution 99-31

July 22, 1999

Identification of Attachments to the Resolution:

Attachment A: Guidance for Power Plant Siting and Best Available Control Technology, issued June 23, 1999.

State of California
California Environmental Protection Agency
Air Resources Board

Guidance for Power Plant Siting and Best Available Control Technology

July 22, 1999

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Table of Contents

Page

PREFACE i

1. EXECUTIVE SUMMARY 1
   - A. INTRODUCTION 1
   - B. BACKGROUND 2
     - 1. What is the purpose of this guidance document? 2
     - 2. How has deregulation of the electric utility industry in California affected power plant construction? 3
     - 3. How will the new power plants differ from plants built before the deregulation of the electric utility industry? 3
     - 4. What are the expected air pollution impacts from the new power plants? 3
     - 5. What is the process for approving power plant construction? 4
     - 6. What areas are covered by this guidance? 4
     - 7. How was this guidance developed? 5
   - C. RECOMMENDATION 5
     - 1. Best Available Control Technology for Large Gas Turbines Used in Electric Power Production 5
     - 2. Emission Offsets 8
       - a. Offset Package Milestones 8
       - b. Interpollutant and Interbasin Emission Offset Ratios 9
     - 3. Ambient Air Quality Analysis 10
     - 4. Health Risk Assessment 10
     - 5. Other Permitting Considerations 10
       - 1. Emission Limits 11
       - b. Equipment Startup and Shutdown 11
       - c. Source Testing and Monitoring 11
       - d. Fuel Sulfur Content 11
       - e. Ammonia Slip 11

II. POWER PLANT SITING IN CALIFORNIA 12
   - A. OVERVIEW 12
   - B. BRIEF DESCRIPTION OF THE CALIFORNIA ENERGY COMMISSION'S POWER PLANT SITING PROCESS 13
   - C. MAJOR AIR POLLUTION REGULATORY PROGRAMS APPLICABLE TO POWER PLANTS 14
   - D. LOCAL AIR DISTRICT'S ROLE IN THE POWER PLANT SITING PROCESS 15
   - E. AIR RESOURCES BOARD'S ROLE IN THE POWER PLANT SITING PROCESS 16

III. BEST AVAILABLE CONTROL TECHNOLOGY FOR LARGE

GAS TURBINES USED IN ELECTRIC POWER PRODUCTION 18
A. SUMMARY OF BACT ANALYSIS..... 18
B. SUMMARY OF INFORMATION AND FINDINGS..... 20
1. Control of NO_X Emissions 21
a. Current SIP Control Measures 21
b. Control Techniques Required as BACT..... 21
c. Emission Levels Achieved in Practice..... 22
d. More Stringent Control Techniques 23
e. Concerns Regarding NO_X Emission Measurement 24
f. Concerns Regarding Ammonia Emissions..... 25
g. BACT Recommendation 26
2. Control of CO Emissions 27
a. Current SIP Control Measures 27
b. Control Techniques Required as BACT..... 27
c. Emission Levels Achieved in Practice..... 28
d. More Stringent Control Techniques 28
e. BACT Recommendation 28
3. Control of VOC Emissions 29
a. Current SIP Control Measures 29
b. Control Techniques Required as BACT..... 29
c. Emission Levels Achieved in Practice..... 30
d. More Stringent Control Techniques 30
e. BACT Recommendation 30
4. Control of PM_{10} Emissions 31
a. Current SIP Control Measures 31
b. Control Techniques Required as BACT..... 31
c. Emission Levels Achieved in Practice..... 32
d. More Stringent Control Techniques 32
e. BACT Recommendation 32
5. Control of SO_X Emissions..... 33
a. Current SIP Control Measures 33
b. Control Techniques Required as BACT..... 33
c. Emission Levels Achieved in Practice..... 33
d. More Stringent Control Techniques 34
e. BACT Recommendation 34
6. Considerations in Controlling Emissions
from Startup and Shutdown..... 34

IV. EMISSION OFFSETS 36
A. OVERVIEW 36
B. GENERAL GUIDANCE 36
1. Completeness of Emission Offset Package 37
a. Emission Information 37
b. Emission Offset Requirements 38
2. Milestones for Securing the Required Emission Offsets 38
C. INTERPOLLUTANT EMISSION OFFSETS AND INTERBASIN EMISSION OFFSETS 39
1. Overall Guidance Perspective 39
2. Specific Guidance on Interpollutant Emission Offsets 40
a. Ozone Precursors (NO_X and VOC) 41
b. $PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X) 42
3. Specific Guidance on Interbasin Emission Offsets 42

22. AMBIENT AIR QUALITY IMPACT ANALYSIS 44
A. OVERVIEW 44
B. MODEL SELECTION AND PROCEDURES 44
C. MODEL INPUT DATA CRITERIA AND QUALITY 46
D. GUIDANCE FOR MODELING SECONDARY POLLUTANT IMPACTS 47

VI. HEALTH RISK ASSESSMENT 48
A. OVERVIEW 48
B. HEALTH RISK ASSESSMENT 48
1. Emissions of Toxic Substances from a Project 49
2. Characterizing Environmental Fate 50
3. Exposure Assessment 51
4. Risk Characterization 51

VII. OTHER PERMITTING CONSIDERATIONS 52
A. OVERVIEW 52
B. GENERAL PERMITTING CONSIDERATIONS 52
C. SPECIFIC PERMITTING CONSIDERATIONS 53
1. Emission Limits 53
2. Equipment Startup and Shutdown 54
3. Source Testing and Monitoring 55
4. Fuel Sulfur Content 56
5. Ammonia Slip 56

Appendices

Appendix A: CALIFORNIA ENERGY COMMISSION CURRENT AND FUTURE SITING CASES

Appendix B: GUIDANCE ON THE PROCEDURE FOR MAKING A BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION

Appendix C: SUPPORTING MATERIAL FOR BACT REVIEW FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

Appendix D: MANUFACTURER EMISSION GUARANTEES FOR NO_X AND AMMONIA SLIP

List of Tables

Page

Table I-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations....7

Table I-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations....7

Table I-3: Minimum Interpollutant Offset Ratios....9

Table I-4: Minimum Interbasin Offset Ratios....10

Table III-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations....19

Table III-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations....20

Table IV-1: Minimum Interpollutant Offset Ratios....40

Table IV-2: Minimum Interbasin Offset Ratios....40

Table VI-1: Pollutants To Evaluate For Health Impacts....50

PREFACE

At a public meeting held on July 22, 1999, the Air Resources Board ("ARB" or "Board") approved the proposed Guidance for Power Plant Siting and Best Available Control Technology (Guidance), which was originally available on June 23, 1999. The Board adopted Resolution 99-31, approving the Guidance. Specific textual amendments to the Guidance discussed at the Board meeting, have been incorporated into this final version of the Guidance document. The changes made to the Guidance are summarized below.

Sections of the Guidance were modified to clarify that continuous emission monitors (CEMs) are not required for volatile organic compounds (VOC) and ammonia (NH_3).

Sections of the Guidance were modified to provide greater flexibility in the recommended frequency of source testing and the monitoring mechanisms to demonstrate compliance with emission limits.

Sections of the Guidance were modified to clarify that ammonia is not a federal hazardous air pollutant or a State-identified toxic air contaminant; however, it is listed under the Air Toxics "Hot Spots" Program due to acute and chronic non-cancer health effects.

Sections of the Guidance were modified to clarify that references to best available control technology (BACT) are intended to address "California BACT," which is equivalent to federal lowest achievable emission rate (LAER).

Sections of the Guidance were modified to clarify that the effectiveness of catalytic systems on the level of oxides of nitrogen (NO_X) emission control is dependent on turbine exhaust gas temperature. Because simple-cycle power plant configurations do not recover heat from the turbine exhaust gas, the temperature may be a consideration in evaluating the applicability of the recommended NO_X BACT emission level for simple-cycle power plants.

Sections of the Guidance related to BACT for particulate matter of 10 microns or less (PM_{10}) and oxides of sulfur (SO_X) were modified to clarify that the natural gas supply does not have to be provided by a Public Utilities Commission (PUC)-regulated utility.

Sections of the Guidance were modified to provide greater flexibility regarding the use of facility-wide emission limits, as long as adequate monitoring is specified.

Staff intends to periodically evaluate the need for modifications to the Guidance for the purpose of modifying recommended BACT emission levels, to make other related modifications, and to incorporate changes in policy. Staff will report back to the Board with these modifications and updates to the Guidance as appropriate. A copy of Resolution 99-31 is attached.

I.

EXECUTIVE SUMMARY

1. INTRODUCTION

In 1996, the Legislature passed a law which deregulated the electric utility industry in California to create a competitive, "open," market system for serving the electricity needs of homes, businesses, industry, and farms (Assembly Bill 1890, Statutes of 1996, Chapter 854). In response, there has been a statewide increase in proposed new power plant construction projects and anticipated projects over the next few years.[1] These power plant projects will need to comply with the requirements of various air pollution control programs. One major program entitled "New Source Review (NSR)" has requirements for emission control, best available control technology (BACT) or lowest achievable emission rate (LAER), and emission offsets. The Air Resources Board's (ARB) guidance set forth in this document will assist local air pollution control districts and air quality management districts (districts) in making permitting decisions as the districts participate in California's consolidated approval process for major power plants. Applicants will also find the information in this document useful in developing their proposed projects.

The State Energy Conservation Commission, more commonly known as the California Energy Commission (CEC), has the exclusive authority for licensing major power plant projects which replaces district authority to construct permits. Other State and local agencies participate in the process to ensure that the projects will comply with applicable laws, ordinances, regulations, and standards. In California, new or modified sources that will emit air pollutants typically must meet certain emission control requirements and obtain preconstruction and operating permits from the district. The district prepares an engineering analysis and places conditions in the permits to ensure that the source will comply with **the requirements of federal, State, and local air pollution regulations. For major power plants under the CEC's jurisdiction, the district's engineering analysis and proposed conditions for the preconstruction permit are submitted to the CEC as a Determination of Compliance**

[1]Appendix A contains the California Energy Commission list of current and future siting cases: 35 projects which range in size from 120 to 1,500 megawatts (MW). The total aggregated electric generating capacity of these projects is in excess of 22,000 MW.

(DOC). However, the district issues and enforces the power plants' operating permits.

This guidance is intended to provide California districts with the information they need to ensure that new power plants employ the best available control technology, and are constructed and operated in away that eliminates or minimizes adverse air quality impacts. The proposed power plants are larger than, and are expected to be operated differently than existing power plants approved in past years. The differences will present new challenges for districts as they review proposed projects to determine whether or not the projects can comply with applicable requirements. This guidance is intended to promote general consistency in the districts' permitting decisions.

This document presents guidance along with some background information on the power plant siting process in California. Chapter I, Executive Summary, provides an introduction, background, and a recommendation. In Chapter II, staff provides background information including brief descriptions of the CEC power plant siting process, applicable air pollution control permit requirements, and the roles of the districts and the ARB. In Chapter III, guidance is provided on air pollution control technology (BACT) for large gas turbines used in electric power production. Guidance on emissions offsets, ambient air quality impact analysis, health risk assessment and management, and other considerations are provided in Chapter IV, Chapter V, Chapter VI, and Chapter VII, respectively. Several appendices are included to provide more detailed or technical information. Air pollution control technology continues to advance at a quick pace. Because of this, staff intends to periodically update this guidance with addendums, that reflect the advancing state of control technology.

B. BACKGROUND

This section briefly discusses the content of this document in question-and-answer format. The reader is directed to subsequent chapters for more detailed discussions.

1. What is the purpose of this guidance document?

The purpose of this document is to set forth guidance to assist districts in making permitting decisions as the districts participate in the CEC's power plant siting process. It will also provide all affected parties an understanding of ARB staff's position in its review of such permitting decisions. This guidance is intended to provide California districts with the information they need to ensure that new power plants employ the best available control technology, and are constructed and operated in a way that eliminates or minimizes adverse air quality impacts. Applicants will also find this guidance useful when developing and planning a proposed power plant project.

2. How has deregulation of the electric utility industry in California affected power plant construction?

Over the next few years, the open market created by the deregulation of the electric utility industry is expected to result in an increase in new power plant construction. Currently, over 22,000 megawatts (MW) in new generating capacity is being considered (based on the 35 current and future projects known to the CEC listed in Appendix A). The majority of the projects are large; individual projects have proposed electric generating capacity in the range of 500 to 1,000 MW. The projects propose to produce electricity using large stationary combustion turbines fueled with natural gas and equipped with state-of-the-art air pollution control technologies. In the 1997 California Energy Plan, the CEC projects that the total statewide peak electricity demand is expected to reach 68,100 MW by the year 2015. The difference in the projected peak demand and in-State installed capacity of 53,700 MW, as of August 1998, is approximately 14,400 MW. The CEC has stated that as much as 6,700 MW of new capacity will be needed between the years 2000 and 2007. These differences are the minimums to meet long-term reserve requirements of the system. In a competitive electricity market, additional new generation resources, beyond the minimum requirements, could compete with existing resources or provide ancillary services. Generation options could include out-of-state generation and transmission, demand-side management, and distributed generation. The 35 projects being proposed, or anticipated, to date would provide an additional 22,000 MW, if they are all constructed; some power plant proposals may never move beyond exploratory discussions.

3. How will the new power plants differ from plants built before the deregulation of the electric utility industry?

The new power plants will operate in the competitive market with more equipment startups and shutdowns and will operate at various power loads; these power plants are commonly referred to as “merchant power plants” that operate in “merchant mode.” Equipment startups and shutdowns will account for a greater proportion of emissions from these new plants, than traditional plants. In general, oxides of nitrogen (NO_X) emissions from the new units will be approximately 0.1 pounds per megawatt-hour (lb/MW-hr) less than emissions from existing power plants. For example, NO_X emissions from an existing gas-fired utility boiler typically would be 0.15 lb/MW-hr as compared to a new gas turbine power plant emitting at 0.05 lb/MW-hr.

4. What are the expected air pollution impacts from the new power plants?

As mentioned, most of the proposed power plants will consist of large stationary combustion turbines. The operation of the turbines with natural gas as fuel and state-of-the art controls is expected to result in some of the lowest emission concentrations achieved to date for this source category. However, despite the benefit of lower emission concentrations, the merchant operation and the large size of the combustion turbines is expected to result in substantial emissions. The emissions are likely to exceed New Source Review (NSR) permitting regulation thresholds for emission offsets for NO_X and carbon monoxide (CO). The larger

projects may also exceed the offset thresholds for particulate matter of ten microns or less (PM_{10}), oxides of sulfur (SO_X), and volatile organic compounds (VOC). Unless adequately mitigated as part of the new source review process, these emissions have the potential to negatively impact ambient air quality.

5. What is the process for approving power plant construction?

California has a consolidated approval process for the siting of major power plants. The CEC has the exclusive authority to approve the construction and operation of power plants that use thermal energy and have an electric generating capacity of 50 MW or larger. The CEC's authority supercedes that of all other State and local agencies. The CEC, however, solicits other local, State, and federal agencies' participation in the power plant siting process to ensure that the construction and operation of power plants will comply with applicable local, State, and federal requirements. The CEC siting process additionally provides full opportunity for public participation.

6. What areas are covered by this guidance?

This guidance document addresses the following five specific areas:

- best available control technology (BACT) - staff's review of recent BACT determinations for large gas turbines used in electric power production and staff's guidelines;

- emission offsets - how to assure that emission offsets provided by the project will be sufficient in quantity and type to provide an air quality benefit, with specific guidance on interpollutant and interbasin offset trading;

- ambient air quality impact analysis - the purpose of an ambient air quality impact analysis and procedures for performing the analysis, if required;

- health risk assessment - the purpose of a health risk assessment for a toxic air contaminant and procedures for performing the analysis, if required; and

- other permitting considerations - identifies the numerous issues that are difficult to address in a permit, including emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip with the utilization of selective catalytic reduction (SCR) control technology.

7. How was this guidance developed?

Consistent with ARB's oversight responsibility for air pollution control programs in California, staff drafted the proposed guidance document and provided it to interested parties for review and comment. On February 24, 1999, staff held a scoping meeting to discuss the BACT component of this guidance. Staff also held public workshops on May 21 and 25, 1999, to discuss the areas covered by the guidance document and on July 6, 1999, to receive comments on the proposed guidance document. Attendees at the workshops included district representatives, CEC staff, electric utilities representatives, equipment manufacturers, and environmental group representatives. Staff has also had numerous conversations with interested parties.

3. RECOMMENDATION

The Board endorses the use of this guidance document by local districts and staff in reviewing and siting major power plants in California. The salient points are as follows:

1. Best Available Control Technology for Large Gas Turbines Used in Electric Power Production

Health and Safety Code Section 42300 authorizes delegation of stationary source permitting authority from the State to local air districts. Each district has its own set of definitions and rules. As a result, the definition of BACT and, where used, LAER can vary by district.

Federal BACT is defined in Section 169(3) of the federal Clean Air Act. It states that the 'term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques,...'

Federal LAER is defined in Section 171(3) of the federal Clean Air Act. It states that the 'The term "lowest achievable emission rate" means for any source, that rate of emissions which reflects --(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.'

Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as "California BACT." One should take note not to confuse "California

BACT" with the less restrictive federal BACT. In the context of this guidance, references to BACT specifically refer to "California BACT."

BACT guidelines for NO_X, CO, VOC, PM_{10}, and SO_X emissions are summarized in Tables I-1 and I-2 for simple-cycle power plant configurations and combined-cycle power and cogeneration power plant configurations, respectively. BACT requirements will change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. Given the regional nature of ozone and PM_{10} precursor pollutants (NO_X and VOC for ozone, and SO_X for PM_{10}), the BACT levels in Tables I-1 and I-2 apply in both attainment and nonattainment areas. Because CO is a localized pollutant and generally attributed to mobile sources, the area attainment status could be considered in establishing BACT to the extent allowed in district rules and regulations. However, factors that may affect the district's BACT determination include, but are not limited to, use of aeroderived versus industrial frame gas turbine for simple-cycle power plant configuration, and the use and function of the gas turbine. When selective catalytic reduction is the control method for NO_X emissions, districts should consider establishing health protective ammonia slip levels at or below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.[2]

The basis for the BACT emission levels in Table I-1 for simple-cycle power plant configurations is as follows:

- for NO_X, the most stringent BACT required and achieved in practice in three consecutive annual source tests;
- for CO, the most stringent BACT required and achieved in practice in three consecutive annual source tests; and
- for VOC, within the range of the most stringent BACT required and based on levels achieved in practice in three consecutive annual source tests.

It should be noted that as exhaust gas temperatures increase, performance and reliability of control systems for reducing NO_X emissions may diminish and should be considered in determining BACT for NO_X emissions from simple-cycle power plants.

[2]Ammonia slip guarantees from several selective catalytic reduction vendors are included in Appendix D.

Table I-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Table I-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

The basis for the BACT emission levels in Table I-2 for combined-cycle and cogeneration power plant configurations is as follows:

- for NO_X, the most stringent emission level deemed BACT by the South Coast Air Quality Management District, recognized as demonstrated in practice by the United States Environmental Protection Agency (U.S. EPA), and the most stringent BACT level proposed for six major power plant projects either approved or currently under review;

- for CO, a reasonable level of emissions based on previous BACT requirements,

emission levels achieved in practice, and BACT levels proposed for major power plants currently under review, with the understanding that flexibility in adjusting the BACT emission level is given to sources in CO attainment areas and where allowed by district rules; and

- for VOC, within the range of the most stringent BACT required and based on levels achieved in practice by similar power plants.

The basis for the BACT emission levels for PM_{10} and SO_X in Tables I-1 and I-2 for both simple-cycle power plant configurations and combined-cycle and cogeneration power plant configurations is the type of fuel combusted and levels of fuel sulfur found in natural gas readily available from California utilities.

2. Emission Offsets

Emission reductions used as offsets need to be specifically identified and quantified in accordance with applicable requirements of district emission reduction credit banking programs and State and federal law. To the extent allowed by applicable programs and law, the emission reduction may be a different type of pollutant than the emission increase (i.e., interpollutant emission offsets) or originate outside the air basin of the proposed project's location (i.e., interbasin emission offsets). Interpollutant or interbasin emission offsets should be allowed only after the applicant has surrendered any applicant-held emission reduction credit certificates and has demonstrated that additional emission reductions are not available onsite. However, the use of interpollutant and interbasin emission offsets must not prevent or interfere with the attainment or maintenance of any applicable ambient air quality standard.

1. Offset Package Milestones

Consistent with CEC power plant siting regulations and procedures, an emission offset package should be complete and secured by the following milestones in the permitting process:

- a complete offset package identified and quantified at the time of submission of the Application for Certification (AFC),

- letters of intent signed by the time the district provides public notice for the preliminary Determination of Compliance (DOC),

- option contracts signed by the time of issuance of the final DOC, and

- offsets secured and in place prior to operation of the power plant. (However, some emission trades may include emission reductions that are contemporaneous; that is, occurring within a designated period ending shortly after commencement of operation.)

2. Interpollutant and Interbasin Emissions Offset Ratios

Minimum interpollutant emissions offset ratios and interbasin emission offset ratios are summarized in Tables I-3 and I-4. The interpollutant offset ratios in Table I-3 are based on recent and past assessments of interpollutant relationships; staff is in the process of developing offset ratios specific to air basins through the utilization of a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year. The interbasin pollutant offset ratios in Table I-4 were derived by staff after surveying district regulatory requirements for the distance offset ratios established in district rules and regulations for use within their respective air basins. However, other methods for determining emission offset ratios may be allowed, consistent with district rules and State law, on a case-by-case basis when justified by the particular circumstances for the proposed project.

The overall emission offset ratios should be determined by combining, unless otherwise specified in district rules, the interpollutant emission offset ratio and the interbasin emission offset ratio, as applicable, and all other applicable district discount or distance ratios; this is a critical requirement when an offset ratio is independent of other ratios in its protection of air quality. With the inherent uncertainties associated with the determination of offset ratios, combining the applicable offset ratios will help ensure that sufficient emission offsets have been obtained to provide an air quality benefit.

Table I-3: Minimum Interpollutant Offset Ratios

Offsetting Pollutants	Minimum Interpollutant Offset Ratio
Ozone Precursors (NO_X and VOC)	Basin specific and no less than 1.0:1
$PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[3]	1.0:1

[3]Due to a lawsuit and the U. S. EPA's implementation schedule for the federal standard, there are no current requirements for $PM_{2.5}$ offsets.

Table I-4: Minimum Interbasin Offset Ratios

Distance Between Project and Offsetting Source	Minimum Interbasin Offset Ratio
Within 50 miles	2.0:1
Over 50 miles	Increase the 2.0:1 by 1.0 for every 25 miles increase beyond 50 miles

3. Ambient Air Quality Analysis

Any evaluation of air quality impacts from a new power plant should be conducted with a model approved by the U.S. EPA and the ARB. A modeling protocol should be prepared and shared with the appropriate regulatory agencies. The protocol should describe the model(s) to be used, how the model will be applied, the types and sources of input data, the assumptions used, and the type of results or outputs. Any modeling conducted for evaluating ozone impacts associated with the proposed use of interpollutant offsets should employ available gridded emission inventories and urban airshed models where available and used in the most recent version of the State Implementation Plan. A protocol will greatly facilitate review of the proposed modeling approach and minimize subsequent technical disagreements. An ARB guidance document, "Technical Guidance Document: Photochemical Modeling, April 1992," is available.

4. Health Risk Assessment

Any health risk assessment for a large power plant project should be conducted consistent with established district policies, or regulations, on health risk assessment for making risk management decisions. When applicable policies or regulations are not in place, health risk should be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (OEHHA) pursuant to Section 44360.b.2. of the Health and Safety Code. Risk management decisions should be consistent with the ARB's "Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, July 1993." Risk assessments prepared for recent proposed power plant projects report that the increase in lifetime cancer risk is less than one in a million.

5. Other Permitting Considerations

Recommendations are provided for adequately addressing the following issues in a power plant permit: emission limits, startup and shutdown of equipment, source testing and monitoring, fuel sulfur content, and ammonia slip.

1. Emission Limits

Permit conditions specifying the emission limits should be expressed in the same form as the underlying regulatory requirement. For example, if a BACT requirement is expressed as an emission concentration measured at a given averaging time and exhaust gas oxygen content, the permit condition implementing the requirement should utilize the same parameters.

2. Equipment Startup and Shutdown

A district should address all phases of plant operations in BACT decisions and assure that controls are required and used where feasible to minimize power plant emissions; permit emission limits should be written to apply to turbine emissions for all potential loads. Emissions generated during equipment startup and shutdown should be regulated by a separate set of limitations to optimize emission control; to regulate these emissions, permit conditions should limit and require record keeping of the number of daily and annual startups and shutdowns. The power plant operator should be required to have a district-approved plan to minimize emissions from equipment startup and shutdown.

3. Source Testing and Monitoring

ARB's goal is to assure initial and ongoing compliance of each power plant with BACT and other emission limits specified in permit conditions. Compliance with BACT and other emission limits is most easily verified through continuous emission monitors (CEMs) and annual source testing, using certified methods that meet district, State, and federal protocols.

4. Fuel Sulfur Content

The permit should include conditions to address SO_X emission levels and to require that the levels be determined using the upper limit of the sulfur content specified in the natural gas supplier's contract.

5. Ammonia Slip

The permit should include conditions to minimize the amount of ammonia slip to a health protective level when selective catalytic reduction is used as a control method; districts should consider establishing ammonia slip levels at or below 5 ppmvd at 15 percent oxygen.

II.

POWER PLANT SITING IN CALIFORNIA

1. OVERVIEW

The California Energy Commission (CEC) has been given authority under State law for a consolidated approval process for the siting of major power plants that use thermal energy.[4] This process allows a project applicant to submit a single application for all necessary State and local approvals. This siting process is intended to avoid duplication, provide a timely review, and provide analysis of all aspects of a proposed project, including need, environmental impact, safety, efficiency, and reliability. The siting process fully satisfies California Environmental Quality Act (CEQA; Sections 21000-21177 of the Public Resources Code) requirements by integrating CEQA's purposes and objectives to assure that all potential impacts of a major project are reviewed.

The CEC has the exclusive authority to approve the construction and operation of power plants that will use thermal energy and have electric generating capacities of 50 megawatts (MW) or larger.[5] The CEC's authority supercedes that of all other State and local agencies, particularly in regards to requirements for permits, and federal agencies to the extent provided by federal law. However, the CEC solicits other public agencies' participation in the power plant siting process to ensure that the construction and operation of power plants will comply with applicable local, State, and federal requirements. For example, the CEC siting process incorporates the local air pollution control and air quality management district's (district) preconstruction permitting program entitled "New Source Review (NSR)." As with non-power plant projects, the district

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[4]Sources of thermal energy include natural gas, synthetic gas, methanol, oil, coal, other fossil fuel, nuclear power, geothermal, biomass, and the sun.

[5]Proposed facilities between 50 to 100 MW may qualify for a Small Power Plant Exemption (SPPE) from the CEC. Exempt projects and projects under 50 MW are subject to the authority of local agencies, including any necessary permits.

independently evaluates the power plant project, prepares permit conditions (e.g., design, operation, and other) to address applicable air quality requirements, and provides public notice and comment opportunity. After the power plant is constructed, the district issues an operating permit and conducts normal enforcement activities to ensure compliance of the power plant with applicable air quality rules and regulations.

The remainder of this chapter briefly describes the CEC power plant siting process, the air pollution regulatory programs applicable to power plants, the role of local air districts, and the role of the Air Resources Board (ARB).

B. BRIEF DESCRIPTION OF THE CALIFORNIA ENERGY COMMISSION 'S POWER PLANT SITING PROCESS

As provided by the 1974 Warren-Alquist Act (Section 25000 *et. seq.*of the Public Resources Code), the CEC's siting responsibilities consist of a statewide planning analysis, a two-phase site approval process, and a compliance monitoring function. A brief description of the overall siting process and identification of the participants is provided below. For more details, consult these CEC documents, "Power Plant Siting," and "Participating in the Siting Process: Practice and Procedure Guide, Second Edition," and siting regulations, "Rules of Practice and Procedures" and "Power Plant Certification Regulations" (Title 20, Division 2, of the California Code of Regulations). Information on current power plant applications is available at the CEC's website.[6]

The Notice of Intention to file an Application for Certification (NOI) is the first of a two-part power plant siting process; the Application for Certification (AFC) is the second phase. Participants are the full decision-making body of the CEC (the Commission), a Commission committee to act as administrative judges, the Hearing Advisor, CEC staff acting as an independent objective party, the Public Advisor, the applicant, the public, other public agencies, and intervenors.[7] All NOIs and AFCs undergo a review process consisting of the following six phases: prefiling, data adequacy, discovery, analysis, hearings, and decision. The NOI phase has a review period of nine months for geothermal projects and 12 months for non-geothermal and

[6]http://www.energy.ca.gov

[7]A public member or agency must apply to become an intervenor. An intervenor is a formal party to the proceedings with certain responsibilities and certain rights not granted to other public members or agencies.

transmission line projects. An AFC exempt from the NOI phase, or an AFC filed within one year of the NOI decision, has a review period of 12 months from its acceptance for filing; otherwise, the AFC phase has a review period of 18 months.

The NOI phase is traditionally used to determine the need for the proposed power plant, site acceptability and suitability, and alternatives to a proposed project. An affirmative NOI decision represents an approval of the proposal in concept. The consideration of a specific site, technology and equipment occurs in the AFC phase. With the deregulation of the electric utility industry, applicants are seeking, and receiving, exemptions from the NOI phase. On May 12, 1999, the CEC announced that it has amended its policies and procedures to allow any proponent for a natural gas-fired merchant power plant project to file an AFC without applying for an NOI exemption.

In the AFC phase, the design, construction, operation, and closure of the power plant is closely examined in relation to applicable laws, ordinances, rules, and standards. Adverse environmental effects are identified and mitigation measures established. The need for the facility is determined, or reconfirmed, if preceded by an NOI. The AFC process ensures that the proposed power plants are safe, reliable, environmentally sound, and comply with all applicable requirements.

C. MAJOR AIR POLLUTION REGULATORY PROGRAMS APPLICABLE TO POWER PLANTS

All proposed power plants must be constructed and operated in compliance with **applicable federal, State, and local air pollution requirements and this compliance must be provided for as one aspect of** the CEC siting process. The new, or modified, power plant is subject to the requirements of several programs established by the federal Clean Air Act; where applicable, the district incorporates the requirements of these programs into its rules and regulations. Additional district rules and regulations implementing measures or programs specified in the State Implementation Plan, the California Clean Air Act (CCAA) of 1988 (Statutes of 1988, chapter 1568), and the district's local air quality plan are also applicable to the power plants.

For power plant projects, the air pollution control program of primary concern is entitled "New Source Review (NSR)." California's NSR permit program is derived from the State Health and Safety Code and the federal Clean Air Act. Each of the districts in California has adopted its own NSR rules and regulations to regulate the construction of new, and modifications to, industrial sources which will emit air pollutants. The control requirements are pollutant specific and depend on an area's attainment status for the ambient air quality standards; a district may have an attainment designation for some pollutants and a nonattainment designation for other pollutants. Each district uses the term, "best available control technology (BACT)" exclusively

when referring to the emission control requirements of their New Source Review permitting programs. With a few exceptions, the district definitions of BACT are based on federal lowest achievable emission rate (LAER) rather than federal BACT.[8] For this reason, BACT definitions in California are often referred to as "California BACT." In addition, larger sources are required to mitigate any remaining emissions after the installation of controls by supplying offsets. Offsets are emission reductions at the project location or at another location. Offsets are needed to mitigate the adverse air quality impacts from the expected increase in emissions from the project.

There is also a federal program for new source performance standards (NSPSs); the NSPSs are regulations adopted by the United States Environmental Protection Agency (U.S. EPA) that define emission limits, testing, monitoring, and record keeping for certain categories of sources or processes (Sections 111 and 129 of the federal Clean Air Act; Title 40 Code of Federal Regulations (40 CFR) Part 60). The NSPS for gas turbines at power plants is contained in Subpart GG of 40 CFR Part 60. The federal program for national emission standards for hazardous air pollutants (NESHAP) is applicable to new and existing sources emitting over ten tons per year (TPY) of one hazardous air pollutant (HAP) or 25 TPY of a combination of HAPs (Section 112 of the federal Clean Air Act; 40 CFR Part 61 and 63); a NESHAP may include a requirement for maximum achievable control technology (MACT). However, electric utility steam generating units are temporarily exempt from MACT requirements by Section 112(n)(1)(A) of the federal Clean Air Act. A proposed power plant is also subject to the monitoring and reporting requirements of Title IV (Acid Rain) of the federal Clean Air Act. An operating power plant will be required to meet the permit requirements of Title V (Major Source Operating Permits) of the federal Clean Air Act. The requirements of Title IV and Title V are implemented through federal regulations in 40 CFR Parts 72-78 and Parts 70-71, respectively, and applicable district regulations.

A power plant project may also be subject to requirements and control measures contained in the State Implementation Plan and local air quality plans. Some districts have rules or policies for reviewing new sources of toxic air contaminants which may include emission control and mitigation requirements at certain health risk levels. A new power plant is subject to the "New Facility Operator Requirement" of the Air Toxics "Hot Spots" Information and Assessment Act of 1987 pursuant to Section 44344.5 of Health and Safety Code. The Air Toxics "Hots Spot" Act (Section 44360 *et seq.* of the Health and Safety Code) established a statewide program for the inventory of air toxics emissions from individual facilities as well as, in certain cases, requirements for risk assessment and public notification of potential health risk.

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[8]In certain districts with attainment, or unclassified, designations for the ambient air quality standards, the BACT definition may be more similar to the less stringent federal requirement which is termed "best available control technology (BACT)". The more stringent federal requirement is termed "lowest achievable emission rate (LAER)" and is required when an area is nonattainment for a standard.

4. LOCAL AIR DISTRICT'S ROLE IN THE POWER PLANT SITING PROCESS

For power plants with 50 MW or greater capacity, the districts' traditional permitting responsibility to control emissions from non-vehicular sources (stationary sources) is incorporated into the CEC's power plant siting process. The CEC's power plant siting regulations specifically provide for the district's participation in the process. The district has the primary responsibility within the AFC process for determining a project's compliance with its NSR permitting regulations and other applicable air pollution control regulations. Each district's regulations may vary depending on the air quality conditions in the district and the district's policies and strategies for attaining or maintaining compliance with the federal and State ambient air quality standards. The district's analysis and recommendations are provided to the CEC in a document known as a Determination of Compliance (DOC).[9]

The district's participation begins early in the process with the review of the application for completeness. The district will also determine if more specific information is needed to assess the acceptability of the project and independently evaluate the project and prepare a preliminary DOC. The preliminary DOC documents the configuration of the power plant, its component sources (equipment), emissions, applicable regulations, and contains an air quality impact assessment. The preliminary DOC additionally contains design, operation, and other conditions needed to ensure compliance with applicable air quality regulations. The district will provide a public notice and comment period for the preliminary DOC. CEC staff recommends that the preliminary DOC be completed within 120 days of the date the CEC finds that the AFC is data adequate; CEC staff will include the preliminary DOC in the CEC's Preliminary Staff Assessment. A final DOC must be provided to the CEC within 180 days of the data adequacy finding for inclusion in the CEC's Final Staff Assessment.

At CEC hearings, the district may be called on to testify on its analysis and recommended conditions in the DOC. If the district has become an intervenor in the siting process, the district may independently provide unrestricted testimony and question other participants. When a project is approved, the CEC decision will contain air quality conditions of certification. In most cases, the conditions will reflect the requirements set forth by the district in its DOC. Additional conditions (e.g., mitigation related to CEQA) may be included at the recommendation of CEC staff. After the power plant is constructed, the CEC compliance monitoring process accommodates district issuance of an operating permit. Via this mechanism, the district can conduct normal enforcement activities to ensure compliance of the power plant with applicable air quality rules and regulations.

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[9]The DOC is functionally equivalent to both the engineering analysis and preconstruction permit, the Authority to Construct, that the district would typically prepare for applications under its jurisdiction.

5. AIR RESOURCES BOARD'S ROLE IN THE POWER PLANT SITING PROCESS

The ARB is the State agency charged with coordinating efforts to attain and maintain federal and State ambient air quality standards and comply with requirements of the federal Clean Air Act (42 U.S.C., Section. 7401, et seq.).[10] The ARB is empowered to do such acts as may be necessary for the proper execution of these powers and duties. State regulations permit, and in some cases require, that the ARB participate in the CEC siting process to help ensure that power plant will be constructed and operated in compliance with all applicable laws, ordinances, regulations, and standards.

The ARB is typically an informal participant in the power plant siting process; however, the ARB also has the option of applying to be a formal participant, an intervenor. Consistent with the ARB's overall responsibilities, staff follows each power plant siting proceeding. Staff will attend many of the workshops and hearings and generally function as a sounding board and resource to the district and CEC staff. Staff will also provide comments to the CEC on the district's preliminary and final DOC, as necessary, to reflect the policies outlined in this guidance. If requested, staff can provide the district and the CEC with technical assistance.

[10]The ARB also has the primary responsibility for control of air pollution from vehicular sources.

III.

BEST AVAILABLE CONTROL TECHNOLOGY FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

A. SUMMARY OF BACT ANALYSIS

This chapter summarizes Air Resources Board (ARB) staff's analysis of best available control technology (BACT) for stationary natural gas-fired turbines (herein referred to as "gas turbines") having a power rating of 50 megawatts (MW) or greater and used for electric power production. General guidance for performing a BACT evaluation is contained in Appendix B. The summary information in this chapter covers control methods for oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter of ten microns or less (PM_{10}), and oxides of sulfur (SO_X) emissions. These control methods include both combustion and add-on control technologies.

In most air pollution control and air quality management district (district) permitting rules, BACT is defined as the most stringent limitation or control technique:

1) which has been achieved in practice,

2) is contained in any State Implementation Plan (SIP) approved by the United States Environmental Protection Agency (U.S. EPA), or

3) any other emission control technique, determined by the Air Pollution Control Officer to be technologically feasible and cost effective.

Staff BACT guidelines are summarized in Tables III-1 and III-2. Different requirements apply to gas turbines used in simple-cycle than apply to combined-cycle and cogeneration power plant configurations. The BACT emission levels in the tables should be considered contemporaneous with the publishing of ARB's guidance. BACT requirements will change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. These emission levels should be used as a starting point in case-by-case analyses. Conditions specific to each gas turbine application may be considered in adjustment of the recommended BACT emission levels. Factors that may affect the BACT determination include, but are not limited to:

- area attainment status,
- gas turbine exhaust gas temperature for simple-cycle power plant configuration (for example, use of aeroderived versus industrial frame gas turbine), and
- use and function of gas turbine.

It is the responsibility of the permitting agency to make its own BACT determination for the class and category of gas turbine application. The BACT emission levels are intended to apply to the emission concentrations as exhausted from the stacks. Summaries of information and findings utilized in assessing BACT for gas turbine emissions follow the tables. Supporting material is presented in Appendix C.

Table III-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Table III-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

B. SUMMARY OF INFORMATION AND FINDINGS

For the purposes of recommending BACT for gas turbines, staff considered the controls for each pollutant and corresponding emission levels in the context of:

- current SIP control measures,
- emission limits and control techniques required as BACT,
- emission levels achieved in practice, and
- more stringent control techniques which are technologically and economically feasible but are not yet achieved in practice.

The BACT emission levels discussed in the following sections apply to those emissions occurring during normal operations and should not be construed as being required during startup and shutdown periods. Factors which should be taken into consideration when limiting emissions from startup and shutdown are discussed at the end of this section.

1. Control of NO_X Emissions

a. Current SIP Control Measures

There are several control measures in approved SIPs that apply to the control of NO_X emissions from gas turbines. These control measures were adopted by local districts to reduce emissions from existing gas turbines. The most stringent of these control measures have been adopted in California with NO_X emission standards based, for the most part, on size, annual operating hours, and control systems employed. The most stringent NO_X requirements are 25 parts per million by volume dry (ppmvd) at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines from 0.3 to under 2.9 MW, 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines rated 2.9 to 10 MW, and 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 10 MW employing selective catalytic reduction. The control measures are applicable to stationary gas turbines (greater than 0.3 MW in size) and provide limited exemptions from the NO_X standards for certain units.[11] These control measures have been adopted to comply with air quality goals of the California Clean Air Act of 1988 and meet a level of stringency referred to as Best Available Retrofit Control Technology (BARCT). BARCT can be more stringent than similar control measures required for the Federal Clean Air Act, which are referred to as Reasonably Available Control Technology (RACT).

[11]Exemptions are generally provided for laboratory units, units used only for firefighting or flood control, emergency standby units, units under 4 MW with limited annual hours of operation, and during startup and shutdown. Exemptions do not preempt the units from all rule requirements. The exemptions primarily apply to requirements for emission limits.

b. Control Techniques Required as BACT

The efficiency of some NO_X control techniques is affected by exhaust temperature. This is especially true of catalytic control techniques. Efficiencies of these controls techniques may be reduced at hot or cold temperatures. For example, high temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, catalysts normally require a minimum temperature before they become chemically active. Flue gas temperatures associated with simple-cycle gas turbines are higher than those of gas turbines used in combined-cycle and cogeneration operations. In the latter, exhaust heat is removed with a heat recovery steam generator (HRSG) resulting in a decrease in flue gas temperatures from the gas turbine (e.g., 1050 °F) to the stack (e.g., 350 °F). On the other hand, simple-cycle gas turbines can have exhaust temperatures ranging up to and around 1100 °F, which vary only slightly from the gas turbine to the stack. Catalysts used for selective catalytic reduction are not as efficient in controlling NO_X at the higher temperatures associated with uncooled exhaust. As a result, gas turbine emissions from combined-cycle and cogeneration operations can be controlled with more efficiency.

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit issued for Carson Energy Group in Sacramento County, California. The permit establishes a limit of 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours with ammonia slip limited to 20 ppmvd at 15 percent oxygen. The determination was made for a 42 MW General Electric LM6000 gas turbine with water injection and selective catalytic reduction. This turbine has been in operation since 1995.

The most stringent BACT limit for a combined-cycle gas turbine was specified in a preconstruction permit issued for the Sutter Power Plant near Yuba City, California. The permit establishes a limit of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour with ammonia slip limited to 10 ppmvd at 15 percent oxygen. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW with dry low-NO_X combustors and selective catalytic reduction. There are other major combined-cycle and cogeneration power plant projects currently going through the California Energy Commission's (CEC) siting process that are proposing a BACT limit of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour. These projects are the High Desert Power Plant, the La Paloma Generating Company, Sunrise Cogeneration, Delta Energy Center, and Metcalf Energy Center. Therefore, to date, one project has been permitted and five projects are in the siting process at this NO_X level~~s~~.

The most stringent BACT limit for an operating combined-cycle gas turbine is 3 ppmvd NO_X at 15 percent oxygen averaged over 3 hours with the ammonia slip limited to 10 ppmvd at 15 percent oxygen. This emission level was achieved on a 102 MW combined-cycle Siemens V84.2 gas turbine at Sacramento Power Authority (Campbell Soup) in Sacramento County, California. The gas turbine is equipped with dry low-NO_X combustors and selective catalytic reduction. This unit has been operating since October 1997.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing on a simple-cycle gas turbine at Carson Energy Group in Sacramento County, California, indicate emissions vary from approximately 3.95 to 4.72 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The 42 MW power plant consists of a General Electric LM6000 gas turbine with water injection and selective catalytic reduction. This gas turbine has been in operation since 1995.

Measurement with continuous emission monitors (CEMs) at Federal Cogeneration in Los Angeles County, California, indicates that an emission level of 2.0 ppmvd NO_X at 15 percent oxygen averaged over 15 minutes was achieved. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. The gas turbine utilizes water injection in conjunction with an after treatment catalyst system called SCONOx. Initially, six months of CEMs data from June to December 1997 were examined by both the U.S. EPA and the South Coast Air Quality Management District (SCAQMD). Upon reviewing this data, the U.S. EPA deemed 2.0 ppmvd NO_X at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. This finding was presented in a March 23, 1998, letter from U.S. EPA to Robert Danziger of Goal Line Environmental Technologies. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging. In correspondence dated June 10, 1998, the U.S. EPA recognized 2.0 ppmvd and 2.5 ppmvd NO_X at 15 percent oxygen with 3- and 1-hour averaging times, respectively, as levels that would represent BACT.

Subsequent to the evaluations by both U.S. EPA and SCAQMD, ARB staff independently verified the performance claims of SCONOx for the seven month period from June 1, 1997 to December 31, 1997 by reviewing CEMs data. Staff's assessment was done through ARB's Equipment and Process Certification Program. Staff verified that the SCONOx system demonstrated emissions of 2.0 ppmvd NO_X at 15 percent oxygen over a 3-hour average with zero ammonia emissions.

d. More Stringent Control Techniques

There are three basic types of NO_X emission controls employed on gas turbines: wet controls using water or steam injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation, and post-combustion controls to reduce NO_X formed in the turbine. While each type of control results in a particular level of NO_X emissions, the potential for reducing NO_X emissions down to single-digit values and fractions thereof has been achieved using controls in combination to reduce NO_X. Common NO_X control combinations currently in use include water or steam injection with selective catalytic reduction, dry low-NO_X combustors with selective catalytic reduction, and water injection with SCONOx. Gas turbine installations equipped with supplemental firing from duct burners generally reduce NO_X emissions using burner combustion controls such as low-NO_X burners. The combination of duct burner, gas turbine combustion, and add-on controls has the potential to reduce NO_X emissions to levels more stringent than what has currently been achieved in practice.

Staff has identified a number of power plant projects with proposed emissions below the achieved in practice level of 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour. One of these projects is for the Sunlaw Energy Corporation which is proposing to meet an emission rate of 1 ppmvd NO_X at 15 percent oxygen averaged over 1 hour for an 840 MW combined-cycle natural gas-fired power plant in Los Angeles County, California. The NO_X emission level is proposed to be achieved using SCONOx. There are no ammonia emissions from the SCONOx technology. This project represents a refining of the SCONOx control technology which is already recognized as achieved in practice at 2.0 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The Application for Certification (AFC) is tentatively scheduled to be filed with the CEC in September 1999. Two projects in Massachusetts, ANP Bellingham and ANP Blackstone, have been conditionally approved with emissions of 2.0 ppmvd NO_X at 15 percent oxygen averaged over 1 hour and 3.5 ppmvd NO_X at 15 percent oxygen averaged over 1 hour during power augmentation with steam injection. Both power plants will consist of two 180 MW ABB GT-24 gas turbines. The NO_X emission levels are proposed to be achieved using selective catalytic reduction. Ammonia slip will be limited to 2.0 ppmvd at 15 percent oxygen averaged over 1 hour. Another Massachusetts project in the proposed stage is the 360 MW Island End Cogeneration. Proposed emission levels are also 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour using selective catalytic reduction.

Emission levels from 1.33 to 4.04 ppmvd NO_X at 15 percent oxygen averaged over 15 minutes measured with a CEMs have been achieved at Silicon Valley Power in Santa Clara, California, utilizing the XONON technology. XONON is a flameless catalytic system integrated into the combustor to lower temperature. This facility consists of a 1.5 MW simple-cycle Kawasaki M1A-13A gas turbine. Once this technology is scaled-up, it may represent the most efficient combustion control for NO_X available for gas turbines. There is not yet sufficient operating experience to ensure reliable performance on large gas turbines. General Electric is currently working with Catalytica Combustion Systems (manufacturer of XONON) to implement the technology on a larger scale.

Coen Company submitted a proposal in February 1999 to ARB's Innovative Clean Air Technology (ICAT) Program to develop and demonstrate a low-NO_X duct burner for cogeneration gas turbine applications. The burner is expected to reduce NO_X emissions below 5 ppmvd at 15 percent oxygen. The project will utilize advanced fuel and air mixing strategies, stability enhancements, and control system design to achieve the target NO_X levels. Use of the new low-NO_X duct burner technology in conjunction with XONON has the potential to match BACT emission levels without the need for add-on control systems such as selective catalytic reduction. Projected date of commercial availability is 2001 to 2002.

e. Concerns Regarding NO_X Emission Measurement

NO_X emissions from gas-turbine power plants employing advanced combustor design and post-combustion controls have been reduced to levels of approximately 2 to 3 ppmvd at 15 percent oxygen. The American Society of Mechanical Engineers (ASME) Codes and Standards Committee B133 is directing an investigation due to its concern that current measurement technologies are not able to produce the precision required for monitoring and testing at the low NO_X levels being identified as BACT. Findings for the first phase of the investigation are detailed in the January 11, 1999, final report "Low NO_X Measurement: Gas Turbine Plants" which investigated the present capabilities available for measuring low NO_X concentrations.

In a letter dated April 28, 1998, the ASME B133 Committee submitted comments to SCAQMD as a result of findings detailed in the January 11, 1999, final report. The letter addressed SCAQMD's proposal to deem 2.5 ppmvd NO_X at 15 percent oxygen BACT for gas turbines based on operating data from the 32 MW Federal Cogeneration plant in Vernon, California. Issues of concern included deficiencies in test protocol, the effect of NO_X removal by water vapor from steam injection, bias induced by permeation and absorption of NO in polymeric tubing, noncompliance of the test procedure used to develop the NO_X levels, and uncertainty of CEM~~S~~s measurement by ±6 ppmvd NO_X.

The SCAQMD issued a response to the ASME concerns in correspondence of May 26, 1998, from Dr. Anupom Ganguli of SCAQMD to Mr. Steve Weinman of ASME. In the letter, the SCAQMD disagreed with the conclusions of ASME and responded in rebuttal to each of the issues mentioned. The SCAQMD ultimately concluded that low NO_X levels can be consistently and accurately measured with the use of currently available measurement technology with a likely accuracy of ±1 ppmvd NO_X. ARB staff are currently investigating the issue of accuracy with regard to current NO_X measurement methods. These methods may need to be revised to assure accuracy at the 2.5 ppmvd level and below.

f. Concerns Regarding Ammonia Emissions

Selective catalytic reduction uses ammonia as a reducing agent in controlling NO_X emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. Currently, ammonia is not regulated by district new source review rules. New source review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient PM_{10} concentrations, it is not listed in any California new source review rule as a precursor to PM_{10}. As a result districts have regulated ammonia slip since the mid-1980's under nuisance and toxic air contaminant rules. The only exception is in the South Coast Air Quality Management District, where ammonia is specifically regulated under a new source review rule.

Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. However, due to acute and chronic non-cancer health effects, ammonia is potentially regulated under district risk management programs. Such programs may include toxic new source review rules/policies and the requirements of the Air Toxics "Hot Spots" Program (Section 44360 *et seq.* of the Health and Safety Code). Ammonia is listed under the "Hot Spots" Program, and therefore, sources are required to report the quantity of ammonia they routinely release into the air.

Ambient particulate matter of 2.5 microns or less ($PM_{2.5}$) is composed of a mixture of particles directly emitted into the air and particles formed in air from the chemical transformation of gaseous pollutants (secondary particles). Principle types of secondary particles are ammonium sulfate and ammonium nitrate formed in air from gaseous emissions of SO_X and NO_X, reacting with ammonia. Studies conducted in the South Coast Air Basin by Glen Cass of Caltech have indicated that ammonia is a primary component in secondary particulate matter. As a result, districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards. Where a significant impact is identified, districts should revise their respective new source review rules to regulate ammonia as a precursor to both $PM_{2.5}$ and PM_{10}.

Gas turbines using selective catalytic reduction typically have been limited to 10 ppmvd ammonia slip at 15 percent oxygen; however levels as low as 2 ppmvd at 15 percent oxygen have been proposed and guaranteed by control equipment vendors. In addition, Massachusetts and Rhode Island have established ammonia slip LAER levels of 2 ppmvd. To date, Massachusetts has permitted two large gas turbine power plants using selective catalytic reduction with 2 ppmvd ammonia slip limits. Given the potential for health impacts and increases in PM_{10} and $PM_{2.5}$, districts should ensure that ammonia emissions are minimized from projects using selective catalytic reduction. Staff recommends that districts consider establishing ammonia slip levels below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.[12]

g. BACT Recommendation

The most stringent NO_X BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The determination was made for a 42 MW General Electric LM6000 simple-cycle gas turbine equipped with selective catalytic reduction. Since 1995, the gas turbine has demonstrated compliance with the NO_X emission limit in three consecutive years of source testing. Considering that the Carson Energy Group represents the most stringent NO_X BACT which has been achieved in practice, staff recommends BACT for NO_X emissions from simple-cycle gas turbines is 5 ppmvd at 15 percent oxygen averaged over 3 hours. It should be noted that as exhaust gas temperatures increase, performance and reliability

[12]Ammonia slip guarantees from several selective catalytic reduction vendors are included in Appendix D.

of control systems for reducing NO_X may diminish and should be considered in determining BACT for NO_X emissions from simple-cycle power plants. For example, the turbine at Carson Energy Group is an aeroderivative gas turbine, which can have lower exhaust gas temperatures than a larger industrial frame gas turbine.

The most stringent BACT limit for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit issued for the Sutter Power Plant near Yuba City, California. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW. It requires 2.5 ppmvd NO_X at 15 percent oxygen using 1-hour averaging, achieved using dry low-NO_X burners and selective catalytic reduction.

Emission levels of 2.0 ppmvd NO_X at 15 percent oxygen using 15-minute averages measured with CEMs were achieved at 32 MW Federal Cogeneration in Los Angeles, California, utilizing water injection in conjunction with SCONOx. Six months of CEMs data were examined by both the U.S. EPA and SCAQMD. Upon evaluation, U.S. EPA subsequently deemed 2.0 ppmvd at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. U.S. EPA acknowledged that future combined-cycle gas turbine projects subject to LAER must recognize the 2.0 ppmvd limit. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging.[13] U.S. EPA correspondence of June 10, 1998, subsequent to this determination recognized 2.0 ppmvd and 2.5 ppmvd at 15 percent oxygen with 3- and 1-hour averaging times, respectively, as levels that would represent BACT.

In light of the U.S. EPA and SCAQMD determinations, staff recommends BACT for NO_X emissions from combined-cycle and cogeneration gas turbines be 2.5 ppmvd at 15 percent oxygen averaged over 1 hour. In addition to the Sutter Power Plant, this NO_X BACT level is being proposed for five other large combined-cycle and cogeneration power plant projects currently going through the CEC siting process.

2. Control of CO Emissions

a. Current SIP Control Measures

Historically, two forms of CO emission controls have been used on gas turbines. Combustion controls were used in the mid-1980's to achieve emission levels down to 10 ppmvd CO at 15 percent oxygen. In the late 1980's, oxidation catalysts were used on larger gas turbine cogeneration units. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. Although oxidation catalysts have been used on simple-cycle gas turbines, the use of oxidation catalysts have been largely limited to cogeneration and combined-cycle gas turbines. High temperature oxidation catalysts are available. Simple-cycle gas turbines with lower flue-gas temperatures have been controlled with high temperature oxidation catalysts.

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[13] NO_X emission averaging time is not included in the BACT summary; however SCAQMD staff report clarifies the averaging time as 1 hour.

Currently, only two areas are designated nonattainment for the California CO ambient air quality standards: Los Angeles County and the city of Calexico in Imperial County. The only area of California designated nonattainment for the national CO ambient air quality standard is the South Coast Air Basin. CO violations arise primarily from concentrated motor vehicle emissions. As a result, districts have not historically instituted control measures that have applied specifically to the regulation of CO emissions from gas turbines. The only California district with a CO emissions limit for gas turbines is the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). SJVUAPCD Rule 4703 limits CO emissions from gas turbines to 25 to 250 ppmvd at 15 percent oxygen averaged over 3 hours, depending on turbine design and use. The control measure is applicable to stationary gas turbines rated at and greater than 0.3 MW.

b. Control Techniques Required as BACT

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit issued for Carson Energy Group in Sacramento County, California. The permit established a CO limit of 5.93 pounds per hour (lb/hr) (equivalent to approximately 5.97 ppmvd at 15 percent oxygen averaged over 3 hours). The determination was made for a 42 MW General Electric LM6000 gas turbine using an oxidation catalyst. This turbine has been in operation since 1995.

The most stringent BACT limit for a combined-cycle gas turbine was specified in a preconstruction permit issued for Newark Bay Cogeneration Partnership in Newark, New Jersey. The permit established a limit of 1.8 ppmvd CO at 15 percent oxygen averaged over 1 hour. This determination applied to a 640 MMBtu/hr Westinghouse CW251/B-12 gas turbine using an oxidation catalyst. The facility is located in a CO nonattainment area.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing at Carson Energy Group in Sacramento County, California, indicate CO emissions vary from 0.07 to 0.29 lb/hr (approximately 0.06 to 0.26 ppmvd CO at 15 percent oxygen). The 42 MW simple-cycle power plant consists of a General Electric LM6000 gas turbine with an oxidation catalyst. This gas turbine has been in operation since 1995.

Two consecutive years of source testing at Crockett Cogeneration in Crockett, California, indicate CO emissions of 1.11 and 2.02 ppmvd CO at 15 percent oxygen. The 240 MW combined-cycle power plant consists of a General Electric Frame 7FA gas turbine with an oxidation catalyst. In addition, two consecutive years of source testing at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate CO emissions of 0.50 and 1.89 lb/hr (approximately 0.16 and 0.62 ppmvd CO at 15 percent oxygen). The 102 MW combined-cycle power plant consists of a Siemens V84.2 gas turbine with an oxidation catalyst.

SCONOx supplier, Goal Line Environmental Technologies, claims SCONOx can achieve

2.0 ppmvd CO at 15 percent oxygen averaged over 1 hour. Goal Line bases this claim upon CEMs data from 32 MW Federal Cogeneration in Los Angeles County, California. The power plant consists of a General Electric LM2500 combined-cycle gas turbine.

d. More Stringent Control Techniques

Source testing at Newark Bay Cogeneration Partnership indicated compliance with a permitted emission limit of 1.8 ppmvd CO at 15 percent oxygen through use of an oxidation catalyst. The facility is a 136 MW cogeneration plant with two 640 MMBtu/hr gas turbines located in Newark, New Jersey. However, source testing is not required on an annual basis, so staff cannot determine whether the level has been demonstrated as "achieved in practice."

e. BACT Recommendation

The most stringent CO BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at approximately 6 ppmvd CO at 15 percent oxygen averaged over 3 hours. The determination was made for a 42 MW General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. Since 1995, the gas turbine has demonstrated compliance with the CO emission limit in three consecutive years of source testing. Considering that the Carson Energy Group represents the most stringent CO BACT which has been achieved in practice, staff recommends BACT for CO emissions from simple-cycle gas turbines is 6 ppmvd at 15 percent oxygen averaged over 3 hours.

With regard to a recommendation for combined-cycle and cogeneration power plants, the most stringent BACT limit for a combined-cycle gas turbine of the size of merchant power plant currently in review with the CEC, was specified in a preconstruction permit issued for Sutter Power Plant near Yuba City, California. The permit established a limit of 4.0 ppmvd CO at 15 percent oxygen averaged over 24 hours. This determination applied to a nominally rated 170 MW Westinghouse 501F gas turbine using an oxidation catalyst. A similar BACT requirement is proposed for Pittsburg District Energy Facility in Pittsburg, California, at 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours. Although the CO emission concentration is higher than that for Sutter Power Plant, staff believes the shorter averaging time represents a BACT level which is more accommodating in determining compliance with emission limits. Therefore, considering available data, staff recommends a BACT emission level of 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours.

The levels recommended for BACT are for CO nonattainment areas. New source review rules require BACT for CO emissions even though most of California is designated attainment for the CO ambient air quality standards. CO standard violations, however, are associated with concentrations of mobile source emissions. Therefore, staff will recognize the need for some flexibility in establishing CO emission controls from new gas turbines in CO attainment areas, where allowed by district rules.

3. Control of VOC Emissions

a. Current SIP Control Measures

Staff is not aware of any existing control measures designed specifically to limit VOC emissions from gas turbines.

b. Control Techniques Required as BACT

Similar to CO emissions, VOC emissions can be abated with combustion controls and oxidation catalysts. Due to low VOC emission concentrations, the control of VOC emissions from gas-fired turbines was relatively unimportant to regulators compared to emissions of $_{NOX}$ and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions. Oxidation catalysts can be designed for control efficiencies of 40 and 50 percent for VOC emissions from gas turbines.

The most stringent BACT limit for a simple-cycle gas turbine was specified in the preconstruction permit for Carolina Power & Light in Goldsboro, North Carolina. The permit established a limit of 0.0015 lb VOC/MMBtu (equivalent to approximately 1.11 ppmvd VOC as methane at 15 percent oxygen). The determination was for a 1,907.6 MMBtu/hr General Electric 7231 FA gas turbine using combustion controls while firing on natural gas.

The most stringent BACT limit for a combined-cycle gas turbine is proposed for the High Desert Power Plant in San Bernardino County, California. Emissions will be limited to 1.0 ppmvd VOC as methane at 15 percent oxygen averaged over 1 hour. The determination is for a 700 to 750 MW power plant using an oxidation catalyst.

c. Emission Levels Achieved in Practice

Three consecutive years of source testing at Carson Energy Group in Sacramento County, California, indicate VOC emissions vary from 0.39 to 1.21 lb/hr (approximately 0.64 to 1.98 ppmvd VOC as methane at 15 percent oxygen). The 42 MW simple-cycle power plant consists of a General Electric LM6000 gas turbine with an oxidation catalyst. This gas turbine has been in operation since 1995.

Two years of source testing at Crockett Cogeneration in Crockett, California, indicate VOC emissions vary from 0.007 to 0.085 ppmvd precursor organic compound (POC) as methane at 15 percent oxygen over a 1-hour average. The 249 MW plant consists of a combined-cycle General Electric Frame 7FA combustion gas turbine with an oxidation catalyst. The 0.007 ppmvd VOC level corresponds to the sensitivity threshold of the source test method. Bay Area Air Quality Management District (BAAQMD) staff indicates a more appropriate characterization of

the measured value is less than 1 ppmvd at 15 percent oxygen.[14]

d. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, designed to limit VOC emissions from gas turbines.

e. BACT Recommendation

Based on VOC emission levels required for simple-cycle gas turbines, the most stringent BACT requirements are in the range of 1 to 2 ppmvd VOC at 15 percent oxygen. Source tests at Carson Energy Group demonstrate VOC emission levels of no more than 2 ppmvd at 15 percent oxygen can be met on a consistent basis. Therefore, staff recommends a BACT emission level for VOC from simple-cycle gas turbines of 2 ppmvd at 15 percent oxygen averaged over 3 hours.

The most stringent VOC BACT requirements for combined-cycle and cogeneration gas turbines have been in the range of 1 to 2 ppmvd VOC at 15 percent oxygen for power plants equipped with oxidation catalysts. Staff recognizes that accuracy of some test methods performed for VOC emissions is uncertain, but available source tests at Crockett Cogeneration and other gas turbine power plants consistently give emission results of no greater than 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour with use of an oxidation catalyst. Based on these findings, staff recommends a BACT level of 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour (or equivalent limit of 0.0027 lb VOC/MMBtu, higher heating value).

4. Control of PM_{10} Emissions

a. Current SIP Control Measures

Staff is not aware of any control measures designed specifically to limit PM_{10} emissions from gas turbines.

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[14]Personal communications with Ken Lim of the Bay Area Air Quality Management District.

b. Control Techniques Required as BACT

PM_{10} emissions are partially dependent on fuel sulfur and nitrogen content. Natural gas has negligible amounts of fuel-bound nitrogen. As a result, there should be negligible nitrate production from any fuel-bound nitrogen. The production of thermally-induced nitrates and the organic fraction of PM_{10} can best be abated through the use of combustion controls. On new gas turbines with state of the art combustion design, PM_{10} emissions are most effectively reduced through use of fuels with both lower sulfur content and low ash content.

There are no add-on control technologies that can feasibly reduce PM_{10} emissions in gas turbine exhaust. As a result, the lowest PM_{10} emissions are achieved through combustion of low-sulfur natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content below PUC-regulated levels.[15] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 grain of total sulfur per 100 standard cubic feet (1 gr S/100 scf).

An example of a recent PM_{10} BACT limit on a large combined-cycle gas turbine was applied to the Sutter Power Plant. A PM_{10} limit of 11.5 lb/hr averaged over 24 hours assuming a fuel sulfur content of 0.7 gr S/100 scf and a 10 percent conversion of fuel sulfur to sulfate emissions. Staff's calculations indicate that this limit is equal to an emission concentration of 0.0013 grains per dry standard cubic feet of exhaust gas (gr/dscf) at 3 percent carbon dioxide (CO_2). This determination applied to a Westinghouse 501F gas turbine nominally rated at 170 MW. In this case, the applicant presumed fuel sulfur content is below the 1 gr S/100 scf specified in the local gas utility company purchase contracts.

c. Emission Levels Achieved in Practice

Two consecutive annual source tests at Carson Energy Group in Sacramento County, California, indicate PM_{10} emissions of 0.63 and 0.882 lb/hr (approximately 0.00025 and 0.00035 gr/dscf at 3 percent CO_2) assuming a fuel sulfur content of 1 gr S/100 scf and 6.5 percent conversion of fuel sulfur to sulfate emissions. The results were obtained on a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine.

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[15]Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

Two consecutive annual source tests at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate PM_{10} emissions of 1.93 and 2.98 lb/hr (approximately 0.00027 and 0.00042 gr/dscf at 3 percent CO_2) assuming a fuel sulfur content of 1 gr S/100 scf and 6.5 percent conversion of fuel sulfur to sulfate emissions. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine.

d. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce PM_{10} emissions from gas turbines**.**

5. BACT Recommendation

The lowest PM_{10} emissions from gas turbines are achieved through combustion of low-sulfur natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content below Public Utilities Commission (PUC)-regulated levels.[16] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, i.e., Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 gr S/100 scf. Staff believe this represents a limiting circumstance in the maximum emission level of the sulfate portion of PM_{10}.

Considering the above, the default PM_{10} BACT requirement for combined-cycle gas turbines is natural gas containing no more than 1 gr S/100 scf. In addition, staff believes that appropriate combustion controls and low sulfur fuel are essential components of a PM_{10} BACT determination for a gas turbine. Any emission limit required for BACT should correspond with a fuel gas sulfur content of 1 gr S/100 scf. Furthermore, there are "housekeeping measures" that can prevent emissions from the lube oil vent, including a lube oil vent coalescer and an associated opacity limit of 5 percent. These latter provisions were required at Badger Creek Limited on a 457.8 MMBtu/hr General Electric LM-5000 gas turbine cogeneration unit with a 48.5 MW capacity.

[16]Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

5. Control of SO_X Emissions

a. Current SIP Control Measures

Several California districts have SIP control measures limiting sulfur compounds (as sulfur dioxide) from fossil fuel-burning equipment used generally for the production of useful heat or power.[17] The most stringent of these limits restrict sulfur dioxide emissions to no more than 200 pounds per hour. This level of emissions is not approached with gaseous fuel combustion.

b. Control Techniques Required as BACT

SO_X emissions are highly dependent on fuel sulfur content. As a result, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Entities regulated by the PUC in California have purchase contracts with an effective maximum total sulfur content for natural gas of 1 gr S/100 scf (equivalent to approximately 17 ppmv sulfur). The most stringent BACT required for a simple-cycle, combined-cycle, or cogeneration gas turbine is firing of low-sulfur natural gas. Natural gas should not contain more than 1 gr S/100 scf if delivered by a California gas utility regulated by the PUC.

The Sutter Power Plant in Sutter County, California, was issued a preconstruction permit for a 170 MW Westinghouse 501F combined-cycle gas turbine. The BACT determination limited SO_2 emissions to no more than 1.0 ppmvd at 15 percent oxygen using 24-hour averaging. This emission level is proposed to be achieved using PUC pipeline quality natural gas for all combustion operations. Staff's calculations indicate that 1.0 ppmvd at 15 percent oxygen is achievable at fuel sulfur contents below 1.8 gr S/100 scf for gaseous fuels assuming full conversion of fuel sulfur to sulfur dioxide.

c. Emission Levels Achieved in Practice

Staff is not aware of any source tests for SO_X conducted on gas turbines that burn natural gas. It appears that source testing is generally not required for gas turbines that burn natural gas exclusively. Because natural gas supplied by a California gas utility regulated by the PUC should not contain more than 1 gr S/100 scf, this represents a limiting factor in SO_X emissions.

d. More Stringent Controls Techniques

SCOSOx is a catalytic sulfur removal system that works in conjunction with the SCONOx system to remove sulfur compounds from combustion exhaust streams. It is nearly identical to

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[17]Such rules may only apply to cogeneration and combined-cycle units. Others may apply more generally and may cover simple-cycle gas turbines.

the SCONOx catalyst for NO_X removal except that it favors sulfur compound absorption and is installed upstream of the SCONOx catalyst. SCOSOx was installed in early 1999 at the Genetics Institute in Andover, Massachusetts in conjunction with SCONOx. The 5 MW cogeneration plant consists of a 65 MMBtu/hr Solar Taurus Model 60 gas turbine with auxiliary-fired HRSG. The SCOSOx system was installed as a "guard bed" for the SCONOx system to enhance the control effectiveness of the NO_X catalyst. In this case, no attempt was made to determine SO_X removal. Therefore, there is no opportunity to assess any SO_X emissions reductions associated with SCOSOx at this time. Goal Line Environmental Technologies is now supplying the SCOSOx catalyst automatically with the SCONOx technology.

5. BACT Recommendation

SO_X emissions result from the oxidation of fuel sulfur during combustion. Staff is unaware of combustion or add-on controls feasible for controlling SO_X emissions from gas turbines. Therefore, staff recommends a SO_X BACT limit equivalent to emissions caused by combusting gaseous fuel with a sulfur content of 1 gr S/100 scf. Based on mass balance calculations and assuming no fuel sulfur conversion to sulfate, a gas turbine firing on natural gas with this level of sulfur content will emit a maximum 0.55 ppmvd at 15 percent oxygen. The district determination may also wish to require as BACT compliance with a fuel sulfur content limit, especially if the content limit is below purchase specification used by the gas utility. In addition, staff suggests that a an emission concentration limit corresponding to the assumed fuel sulfur content, i.e., 0.55 ppmvd at 15 percent oxygen or lower, may be appropriate.

6. Considerations in Controlling Emissions from Startup and Shutdown

Due to deregulation of the electric utility industry in California, many new power plants will be operating under merchant mode. Recent applications for power plant certifications indicate these plants will operate under varying loads with numerous startups and shutdowns to handle changing electricity demands. Gas turbines generally have higher emissions during periods of startup and shutdown. In fact, startup and shutdown emission may substantially contribute to the total project emissions. Therefore, the BACT decision should consider control of emissions during such periods of operation.

Gas turbines are designed to run online near rated capacity. Optimal combustion in a gas turbine tends to occur at full load. In addition, emission control systems, especially those dependent on feedback systems, operate best at steady-state. In this post deregulation period, gas turbine~~s~~ power plant<u>s</u> may spend a significant amount of time in other modes of operation. Derated operation can be associated with less efficient combustion. Startup, shutdown, and load changes will cause variations of flue gas flows and temperature. Periods of disequilibrium may be frequent and long. For example, cold startups for combined cycle units may require up to four hours.

To the extent possible, emissions should be controlled where possible, including during

startups and shutdowns. Emission control systems should operate when circumstances allow and use of bypass stacks should be minimized. For example, if flue gas temperatures are within the effective temperature window of the catalytic control system, emission control systems should be in service, and emissions controlled to the maximum extent allowed by circumstances. Also, startup and shutdown should be minimized with permit conditions limiting their duration. Definitions of startup and shutdown should be well delineated with precise definitions that include markers that clearly distinguish the onset and conclusion of such events. Districts may want to limit startup and shutdown emissions where it is possible to enforce such limits.

Commenters have also suggested other more specific ways of reducing startup and shutdown emissions. They include the following:

- using an auxiliary boiler or other source of steam turbine sealing steam to reduce startup times,

- using a stack dampener to maintain high temperatures in the HRSG during shutdown, thereby allowing a hot or warm startup instead of a cold startup,

- early injection of ammonia into the selective catalytic reduction unit,

- using alternatives to the widely used low-NO_X combustor technology (These include XONON, which can achieve 3 ppmvd NO_X at 15 percent oxygen and will soon be offered and guaranteed on General Electric gas turbines), and

- investigate ways to more quickly heat catalysts to operation temperature.

At a minimum, districts should require applicants to submit a plan for district approval, to minimize emissions during equipment startups and shutdowns.

IV.

EMISSION OFFSETS

A. OVERVIEW

Air pollution control and air quality management district (district) new source review (NSR) rules and regulations employ both best available control technology (BACT) and emission offset requirements to reduce the impact on air quality from new or modified stationary sources. If emission increases are above certain specified levels, district NSR rules require the application of BACT. If the emission increases after the installation of BACT are still above specified levels, then emission offsets may be required. Emission offsets are emission reductions at the project location, or at a nearby location, to compensate for the expected increases in emissions from the project. An overall air quality benefit is expected if the offsets (emission reductions) are greater than the emission increases from the project (i.e., if the emission offset ratio is greater than 1.0:1) and the emission increases are not expected to result in a new violation, or add to an existing violation, of ambient air quality standards within the impact area of the power plant.

Even though state-of-the-art controls, as discussed in the previous chapter, will drive emission concentrations to some of the lowest levels ever achieved for stationary combustion turbines, the proposed power plants, because of their size, will still emit substantial quantities of pollutants. Emissions from the proposed power plants are expected to exceed specified levels for emission offsets for oxides of nitrogen (NO_X) and carbon monoxide (CO); however, most areas in California have been designated attainment with the federal and State CO standards and do not require CO offsets. In CO nonattainment areas, most projects will avoid CO offset requirements due to a common provision in many districts' NSR rules and regulations; offsets will not be required if modeling demonstrates that there is not a violation of the air quality standard at the proposed project site and that the emission increase will not cause or contribute to a violation of the standard. In addition, the larger-sized projects may also exceed offset thresholds for particulate matter of ten microns or less (PM_{10}), oxides of sulfur (SO_X), and volatile organic compounds (VOC).

B. GENERAL GUIDANCE

Emission reductions used as offsets should be specifically identified and quantified in accordance with applicable requirements of district emission reduction credit banking programs and State and federal law. Emission offsets must be real, quantifiable, surplus, permanent, and enforceable. Emission reductions which are real are those that have actually occurred, not those

that could have been emitted but were not. Quantifiable means that the amount of emission reduction can be determined with reasonable certainty. Surplus reductions are those reductions which are not encumbered by any local, State, or federal law, regulation, order, or requirement. Permanent means that the benefits of the emission reduction do not diminish or disappear over time. Reductions which can be checked and verified by field inspection or source testing are enforceable.

The generation of emission reductions from sources not required to have permits must be consistent with the requirements of Section 40714.5 of the Health and Safety Code and applicable district rules and regulations and meet emission banking criteria otherwise required for sources with permits. Emission reductions from mobile sources[18] or area stationary sources should be banked and transferred under an interchangeable credits rule adopted by the district and approved by the Air Resources Board (ARB). To the extent allowed by a district's rules and regulations and State law, the emission reductions may be a different type pollutant than the emission increase (i.e., interpollutant emission offsets) or originate outside the air basin of the proposed project's location (i.e., interbasin emission offsets).

1. Completeness of Emission Offset Package

An application should contain a complete emission offset package and include sufficient emission information to verify the type and quantity of required emissions offsets.

a. Emission Information

Emission offset requirements are calculated using detailed emissions information. Therefore, emission estimates and supporting information for all proposed operating scenarios of the power plant, including alternative operating scenarios, should be submitted to the California Energy Commission (CEC) in the Application for Certification (AFC). The emission estimates and supporting information should meet the following criteria:

- be clearly depicted,
- be supported by equipment-specific data with sources of information referenced,
- be sufficient to verify each step of the emission calculations, and
- reflect the worst-case potential impact on ambient air quality with the worst-case

[18]ARB has established guidance for the generation of emission reductions from mobile sources in a document entitled, "Mobile Source Emission Reduction Credits: Guidelines for the Generation and Use of Mobile Source Emission Reduction Credits, February 1996."

operating scenario identified for each pollutant emitted.

b. Emission Offset Requirements

The quantity of emission offsets should be calculated in accordance with district requirements, including any applicable offset ratios. Offset ratios normally increase with increasing distance between the project site and the source of the emission reductions. Where district rules do not address such ratios, an appropriate ratio can be established provided technical justification can show that the use of the ratio will not have a negative impact on air quality.

The district's preliminary determination of compliance (DOC) regarding the application should evaluate whether, or not, the applicant's emission~~s~~ offset package is complete and has made the following demonstrations:

- the amount of emission offsets required has been calculated in accordance with district requirements;
- any emission reductions provided that have not been banked in accordance with district regulations are real, quantifiable, surplus, permanent, and enforceable and based on worst-case operating scenarios;
- emission reductions not banked by the date of preliminary DOC issuance have undergone any adjustments required by district rules and regulations including adjustments for BACT, Best Available Retrofit Control Technology (BARCT), and Reasonably Achievable Control Technology (RACT); and
- the applicant has demonstrated (through letters of intent, option-to-purchase contracts, or the equivalent) intent and ability to secure, in a timely manner, any emission~~s~~ offsets from sources not under the applicant's direct control.

2. Milestones for Securing the Required Emission Offsets

The emission offsets package should be complete and secured by the following milestones in the permit process:

- a complete offset package identified and quantified at the time of submission of the Application for Certification (AFC),
- letters of intent signed by the time the district provides public notice for the preliminary DOC,
- option contracts signed by the time of issuance of the final DOC, and

- offsets secured and in place prior to operation of the power plant (However, some emission trades may include emission reductions that are contemporaneous; that is, occurring within a designated period ending shortly after commencement of operation.).

Any significant changes in the offsets package after the preliminary DOC is issued should be subject to additional public notice to ensure that a full and completed public process occurs.

3. INTERPOLLUTANT EMISSION OFFSETS AND INTERBASIN EMISSION OFFSETS

1. Overall Guidance Perspective

Staff recommends that interpollutant or interbasin emission offsets be allowed only after the applicant has surrendered any applicant-held emission reduction credit (ERC) certificates, and has demonstrated that additional emission reductions are not available onsite or near the source.

In this document, staff is providing guidance for determining emission offset ratios for interpollutant emissions offsets and interbasin emission offsets. Staff recommends the interpollutant emissions offset ratios and interbasin emission offset ratios as summarized in Tables IV-1 and IV-2, respectively. The minimum interpollutant offset ratios in Table IV-1 are based on recent and past staff assessments of interpollutant relationships; staff is in the process of developing offset ratios specific to air basins through the utilization of a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year. Where district rules and regulations do not specifically establish interbasin offset ratios, staff recommends the interbasin pollutant offset ratios specified in Table IV-2. The minimum interbasin pollutant offset ratios in Table IV-2 were derived by staff after surveying district regulatory requirements for distance offset ratios established in district rules and regulations for use within their respective air basins. However, staff recommends that other methods for determining emission offset ratios be allowed, consistent with district rules and regulations and State law, on a case-by-case basis when justified by the particular circumstances for the proposed project.

Overall emission offset ratios should be determined by combining, unless otherwise specified in district rules and regulations, the interpollutant emission offset ratio and the interbasin emission offset ratio, as applicable, and all other applicable district discount or distance ratios; this is a critical requirement when an offset ratio is independent of other ratios in its protection of air quality. With the inherent uncertainties associated with the determination of the offset ratios, combining the applicable offset ratios will help ensure that sufficient emission offsets are provided to provide an air quality benefit.

Table IV-1: Minimum Interpollutant Offset Ratios

Offsetting Pollutants	Minimum Interpollutant Offset Ratio
Ozone Precursors (NO_X and VOC)	Basin specific and less than 1.0:1
$PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[19]	1.0:1

Table IV-2: Minimum Interbasin Offset Ratios

Distance Between Project and Offsetting Source	Minimum Interbasin Offset Ratio
Within 50 miles	2.0:1
Over 50 miles	Increase the 2.0:1 by 1.0 for every 25 miles increase beyond 50 miles

2. Specific Guidance on Interpollutant Emission Offsets

Where emission reductions of the same type of pollutant are not available, some districts' rules and regulations may allow the use of interpollutant offsets. The use of interpollutant emission offsets should be allowed only under the following circumstances:

- the applicant demonstrates that emission reduction credits of the same type of pollutant as the emission increase are not available onsite,
- the applicant has used any applicant-held ERC certificates, and
- the use of interpollutant emission offsets does not prevent or interfere with the

[19]Due to a lawsuit and the United States Environmental Protection Agency's (U. S. EPA) implementation schedule for the federal standard, there are no current requirements for $PM_{2.5}$ offsets.

attainment or maintenance of any applicable ambient air quality standard, consistent with Section 42301 of the Health and Safety Code.

1. Ozone Precursors (NO_X and VOC)

As summarized in Table IV-1, staff recommends that interpollutant emission offsets of ozone precursors (NO_X and VOC) be allowed if the offsets required are calculated with an interpollutant offset ratio that is a minimum ratio of 1.0:1 and specific for the air basin in which the project is proposed. Staff is in the process of developing ratios for air basins throughout the State. To the extent offsets are calculated with ratios specified in district rules and regulations or developed by ARB staff, the technical assessment of the applicant's emission offset package can be minimized. In lieu of ARB ratios, the applicant can make a case-by-case determination of the interpollutant offset ratio if the ratio can be technically justified in a manner approved by the district, ARB, and the U.S. EPA; this ratio cannot be less than 1.0:1.

Staff is in the process of developing interpollutant offset ratios specific to an air basin utilizing a photochemical grid model (where available) and a gridded emission inventory for the ozone attainment year.[20] If the applicant chooses to do a case-by-case determination of an interpollutant offset ratio utilizing a photochemical model, the modeling protocol should be consistent with the following criteria:

- ARB's 1992 guidance document, "Technical Guidance Document: Photochemical Modeling;"
- use of the projected attainment emissions inventory from the latest approved air quality plan as a starting point; and
- use of the most up-to-date VOC speciation profiles, which can be obtained from ARB staff.

Prior to carrying out any analyses, the applicant would need to discuss the use of new emission inventories and updated VOC speciation profiles with appropriate regulatory agencies. The ARB maintains a library of VOC speciation profiles for different source types which are documented in the ARB's 1991 speciation manual, "Identification of Volatile Organic Compound Species Profiles," and updates to this information.

[20]This is the year in which the federal ozone standard is projected to be attained in the latest local air quality plan. The attainment date for the 1-hour ozone standard varies based on an area's severity of pollution.

b. $PM_{2.5}$, PM_{10}, and Precursors (NO_X, VOC, and SO_X)[21]

As summarized in Table IV-1, staff recommends that the interpollutant emission offsets for particulate matter of 2.5 microns or less ($PM_{2.5}$), particulate matter of 10 microns or less (PM_{10}), and precursors (NO_X, VOC, and SO_X) be allowed at a minimum interpollutant offset ratio of 1.0:1. However, interpollutant offsets cannot be used where the offsetting pollutant contributes to the violation of another standard. For example, NO_X increases cannot be offset with PM_{10} reductions in an ozone nonattainment area and, upon implementation of requirements, $PM_{2.5}$ increases cannot be offset with PM_{10} reductions in a $PM_{2.5}$ nonattainment area. Also, the interpollutant offset ratio minimum of 1.0:1 may not hold true for $PM_{2.5}$ in all areas. A minimum 1.0:1 ratio can be used in areas that do not have a $PM_{2.5}$ air quality problem; where a problem exists, a minimum ratio of 1.0:1 can be used until sufficient data becomes available for the ARB, or other regulatory agencies, to reevaluate the minimum ratio or determine appropriate ratios.

3. Specific Guidance on Interbasin Emission Offsets

Interbasin emission offsets should be allowed only for ozone precursors (NO_X and VOC) and PM_{10} precursors (NO_X, VOC, and SO_X) under the following circumstances:

- the use of the interbasin emission offsets meets the following minimum requirements of Section 40709.6 of the Health and Safety Code:
  - the stationary source to which the emission reductions are credited is located in

[21]In response to a recent lawsuit, the U.S. Court of Appeals for the District of Columbia has invited comment on the federal $PM_{2.5}$ standard, which could range from retention to removal of the standard. If the standard is retained, requirements for $PM_{2.5}$ offsets are not anticipated until after a district receives a non-attainment designation and has prepared the required implementation plan; this will be after the year 2006 according to the U.S. EPA's implementation schedule.

an upwind district that is classified as being a worse nonattainment status than the downwind district,
  - the ARB has established that there is an emission transport relationship between the two districts and an overwhelming impact on the downwind district accepting the offsets,[22]
  - the downwind district accepting the offsets has adopted a rule to discount the emission reduction credits from the upwind stationary source, and
  - the interbasin emission offsets transaction has been approved by both districts;

- the applicant demonstrates that emission reductions are not available onsite;

- the applicant has used any applicant-held ERC certificates; and

- the interbasin offset ratio is combined, unless otherwise specified in district rules and regulations, with any other applicable ratios.

Where district rules and regulations have not specified interbasin offset ratios, staff recommends the ratios summarized in Table IV-2. The minimum interbasin offset ratios provided by staff are based on a survey of district distance offset ratios and have been established at a sufficiently high level to account for uncertainties, where staff would expect an air quality benefit. If consistent with district requirements, staff recommends a minimum interbasin emission offset ratio of 2.0:1 for sources within 50 miles. When the distance between sources is greater than 50 miles, staff recommends that the minimum interbasin offset ratios be increased by one for each additional 25 miles distance between the sources; for example, when the distance between two sources is 100 miles, the recommended minimum interbasin offset ratio is 4.0:1.

Staff's ratios are not intended to prevent an applicant or a district from developing other interbasin offset ratios based on a detailed technical analysis. It should also be noted that staff's

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[22]Transport couples are designated with one or more transport characterizations (i.e., overwhelming, insignificant, or inconsequential). Where a transport couple is identified with more than one transport characterization and one of which is an overwhelming designation, the transport characterization can be considered overwhelming for the purpose of this interbasin emission offset guidance. The current list of designations can be found in the ARB publication entitled "Second Triennial Review of the Assessment of Impacts of Transported Pollutants on Ozone Concentrations in California."

interbasin emission offset ratios are distance ratios; if district offset requirements already include an equally protective distance offset ratio, additional discounting of the offsets for distance between sources may not be necessary.

V.

AMBIENT AIR QUALITY IMPACT ANALYSIS

1. OVERVIEW

One of the primary concerns in siting a new project, especially a large power plant, is its impact on air quality. The benchmarks of acceptable air quality are normally State and federal ambient air quality standards. Section 42301(a) of the Health and Safety Code requires district permit systems to ensure new permits will not be issued for emission units (sources) that will prevent or interfere with the attainment or maintenance of any applicable air quality standard. For this reason, air quality impacts should be evaluated for each State and national ambient air quality standard potentially impacted by emissions from a project. Another concern may be the project's potential to cause a significant degradation of air quality. This latter concern is addressed by Part C of Title I of the federal Clean Air Act (Prevention of Significant Deterioration) and the California Environmental Quality Act.

Air quality models are the primary tools for relating emissions to air quality impacts. Models, in turn, require acceptable input data for emissions, surface topography, meteorological parameters, receptor configurations, baseline air quality, and initial and boundary conditions for each modeling scenario. Since the quality and reliability of model outputs can never be any better than the inputs, quality control of the input data is an important concern.

2. MODEL SELECTION AND PROCEDURES

The baseline air quality and anticipated emission behavior of the project must be characterized before structuring the air quality impact analysis. The baseline air quality may be characterized as representative background air quality, or it may be represented as a particular air quality scenario associated with worst-case air quality experienced at some point in the past. It is also important that any modeled emission scenario is appropriate for evaluating the project's future compliance with the given regulatory requirement (e.g., assessment of long-term health impacts). Project emission rates used for air quality impact modeling should clearly depict and reflect worst-case conditions for any operating scenario requiring evaluation.

Any evaluation of air quality impacts from a new power plant should be conducted with models approved by the U.S. Environmental Protection Agency (U.S. EPA) and the ARB. Models should be appropriate for the pollutants and scenarios to which an air quality impact analysis is applied. The measurement parameters for assessing air quality impacts should consider

the applicable state and national ambient air quality standards, for all relevant averaging times. Any air quality models used should be readily available to the public in source code format ("public domain") and should have no restrictions regarding modifications to the model. In addition, the model(s) should have undergone peer review, undergone one or more model performance evaluations, and be properly documented.

ARB strongly recommends that a modeling protocol be prepared and shared with the appropriate regulatory agencies. The protocol should describe the model(s) to be used, how the model will be applied, the types and sources of input data, the assumptions used, and the type of results or outputs. A protocol will greatly facilitate review of the proposed modeling approach and minimize subsequent technical disagreements. An ARB guidance document, "Technical Guidance Document: Photochemical Modeling, April 1992;" is available.

The proposed modeling grid should be sufficient to address all relevant source-receptor relationships. The resolution of the grid and area of coverage should be documented in the modeling protocol. For photochemical pollutant modeling, nested grids (a fine resolution grid near a source embedded within a larger grid) may be used provided they are properly documented and justified in the modeling protocol. For inert pollutant modeling, a fine grid nested within a coarse grid is appropriate to determine the point of maximum pollutant concentration. If sources have significant effective plume rise (e.g., 50 meters or more), a minimum fine grid resolution of 100 meters is required to estimate the point of maximum pollutant concentration. For emissions with an effective plume height closer to the ground, a finer grid resolution may be required.

Prior to investing resources in a refined analysis, a screening analysis may be employed using worst-case assumptions to determine if there will be a potential air quality problem. If a screening analysis indicates a potential air quality problem, a refined analysis is needed. Refined analyses utilize better models and data to provide an improved estimate of air quality impacts.

All aspects of an air quality impact analysis should be thoroughly documented prior to submission for regulatory review. Documentation should address all assumptions and procedures, and provide the following information:

- the state of current air quality in the project impact area;
- the selection of modeled scenarios;
- the selection of air quality models;
- characteristics of the modeling grid;
- emission inputs, including any temporal or spatial apportionment;
- meteorological input data, including data quality and representativeness;

- air pollutant concentration input data, including data quality and representativeness;

- air pollutant concentration output data and any other model outputs, including interpretive limitations associated with procedural assumptions, input data, or theoretical basis of the model; and

- all model input files, including the model source code, should be available on computer ready media (e.g., CD-ROM or diskette) and made available, if requested.

3. MODEL INPUT DATA CRITERIA AND QUALITY

In a broad sense, there are three categories of environmental data inputs into a model, i.e., terrain elevation, meteorological, and air quality data. The simplest category to address is terrain elevation data. Terrain elevation data used should be consistent with the grid resolution(s) chosen. The U.S. Geological Survey is a standard source for terrain data.

Any meteorological data used should comply with the requirements for data collection and quality assurance described in U.S. EPA's "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume IV, Meteorological Measurements, 1989," and supplemented by U.S. EPA's "On-Site Meteorological Program Guidance for Regulatory Modeling Applications, 1995." For photochemical modeling, the meteorological data should be specific to the modeled episode. For inert modeling, the U.S. EPA recommends five years of representative meteorological data when estimating concentrations with an air quality model. In this case, the most recent readily available consecutive five-year period should be used. There may be conditions where no data are representative of the facility. In such conditions, either a screening evaluation should be performed or a meteorological collection program should be established to gather a minimum of one year of site-specific meteorological data.

All air quality input data for the model should be both spatially and temporally representative of the area for which it is applied. The representativeness of the data used should be described in the modeling protocol. Background values used for inert modeling should be based on pollutant concentration measurements. The measurements and assumptions used to determine background concentrations should be described in the modeling protocol. Boundary and initial conditions should be based on specific observations for the episode undergoing photochemical modeling, or reasonable assumptions based upon available meteorological and air quality measurements for inert modeling.

4. GUIDANCE FOR MODELING SECONDARY POLLUTANT IMPACTS

When modeling NO_X emissions impacts on ambient NO_2 concentrations, a tiered approach is normally used to estimate NO_2 concentrations for a source. Under the first tier, 100 percent conversion of NO_X to NO_2 is assumed. In successive tiers, it is recommended that the Ozone Limiting Method (OLM) as specified in the U.S. EPA Modeling Guidelines be used; it assumes ten percent of plume NO_X and 100 percent conversion of remaining NO_X as a function of ozone availability. A more refined approach is to conduct hour-by-hour simulations using hourly values of ozone, NO_2, and NO_X emissions.

For sources with ammonia emissions, districts may want to consider the impacts of ammonia on secondary particulate matter emissions from the project and on ambient PM_{10} concentrations.

VI.

HEALTH RISK ASSESSMENT

A. OVERVIEW

A health risk assessment is an evaluation of the potential for adverse health effects that can result from public exposure to emissions of toxic substances. The information provided in the health risk assessment, if required, can be used to decide if or how a project should proceed. Applicants for large power plant projects have typically been required to submit risk assessments to satisfy California Environmental Quality Act (CEQA) review requirements for potential impacts. Applicants may also use the risk assessments, and associated emission assessments, to satisfy the new facility operator requirement of the Air Toxics "Hot Spots" Program in Section 44344.5 of the Health and Safety Code. Risk assessments prepared for recent proposed power plant projects report that the increase in lifetime cancer risk is less than one in a million.

Some air pollution control and air quality management districts (districts) may have regulations, or established policies, on health risk assessments for making risk management decisions; some examples of such districts include the South Coast Air Quality Management District and Monterey Bay Unified Air Pollution Control District, which both have regulations that specifically identify the type of projects for which health risk assessments must be submitted. Other districts have relied upon the authority provided by Section 41700 of the Health and Safety Code to manage health risk impacts. When applicable policies or regulations are not in place, staff recommends that health risk be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (OEHHA) pursuant to Section 44360.b.2 of the Health and Safety Code. Staff also recommends that the district make decisions consistent with the Air Resources Board's (ARB) "Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, July 1993."

2. HEALTH RISK ASSESSMENT

A health risk assessment should address three categories of health impacts from all pathways of exposure, if appropriate: acute health effects from inhalation only, chronic non-cancer health effects, and cancer risks from multiple exposure paths. Acute health effects generally result from short-term exposure to high concentrations of pollutants. Chronic non-cancer health effects, such as lead intoxication affecting the nervous system, and cancer risks may result from long-term exposure to relatively low concentrations of pollutants.

Important steps to take when evaluating health impacts include determining the emissions

of toxic substances from a project, characterizing the environmental fate of the toxic substances, and assessing the public's exposure to the toxic substances. In the final step of a health risk assessment, health impacts are characterized by combining the output from an air dispersion model with pollutant specific unit risk factors (for cancer effects) or reference exposure levels (for acute and chronic non-cancer effects).[23]

1. Emissions of Toxic Substances from a Project

The health risk assessment should identify the toxic substances of concern and the quantities that may be emitted from the power plant. The assessment may need to focus on certain criteria air pollutants [24] and different toxic substances for each of the three categories of health effects to be evaluated. The toxic substances of concern may also vary from one project to another because of differences in the basic equipment and emission controls that are proposed. According to information obtained through the Air Toxics "Hot Spots" Program, the criteria air pollutants and toxic substances identified in Table VI-1 should be addressed, at a minimum, when assessing the health risk associated with power plants equipped with combustion turbines that will be fueled with natural gas.

After the toxic substances of concern are identified, the quantity of emissions from the power plant must be estimated. Emission estimates may be developed from the information reported to the Air Toxics "Hot Spots" Program; however, it should be noted that this information does not focus on criteria air pollutants. An ARB guidance report, "Emission Inventory Criteria and Guidelines for the Air Toxics 'Hot Spots' Program, May 15, 1997," is available. Alternatively, emission factors based on source tests conducted on similar facilities may be used to estimate the quantity of toxic substances that will be emitted from a proposed power plant. Ideally, the emission factors would be derived from a source test of the same model turbine equipped with similar combustion devices and air pollution control equipment, and operated in the same manner as the proposed power plant.

In general, all emission estimates should reflect the operation of the power plant at maximum capacity and steady-state operation. However, emission estimates should be developed for all anticipated modes of operation that would result in worst-case impacts for the specific

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[23]Reference Exposure Levels and Unit Risk Factors may be obtained from the Office of Environmental Health Hazard Assessment (OEHHA).

[24]The term "criteria air pollutants" is used here to refer pollutants such as oxides of nitrogen (NO_X) and carbon monoxide (CO) for which there are ambient air quality standards.

health effects being evaluated. For example, emission estimates developed to evaluate acute health effects should be based upon predictable process upsets. An assessment of acute health effects should include, at a minimum, the impacts from equipment startup, equipment shutdown, and any other situations where the air pollution equipment may be by-passed or operated well below typical operating efficiency. For assessment of non-cancer and cancer health effects, the emission estimates should reflect the expected long-term operation of the power plant which would include emissions from steady-state operation, emissions during periods of process upsets, and emissions from the startup and shutdown of equipment.

Table VI-1: Pollutants To Evaluate For Health Impacts

Acute Health Effects	
Ammonia (w/ SCR only)	Formaldehyde
Carbon Monoxide	Oxides of Nitrogen
Chronic Non-Cancer Health Effects	
Acrolein	Ammonia (w/ SCR only)
Benzene	Formaldehyde
Naphthalene	Nitrogen dioxide
Phenol	Propylene
Toluene	Xylenes
Cancer Risks	
Acetaldehyde	Benzene
Formaldehyde	

2. Characterizing Environmental Fate

The applicant will need to characterize the extent to which a power plant's toxic emissions will impact the surrounding environment. Air dispersion models should be used to predict the ambient air concentrations of the toxic substances emitted by a power plant. It is necessary to determine the highest emission concentrations, where they will occur, and the ground-level concentrations of the toxic substances at other points of interest (e.g, nearby schools and residences). The assessment must identify the exposure media. The common routes by which humans can be exposed to toxic substances are breathing ambient air, contact by touching a contaminated object, and eating or drinking items contaminated by the substance. Staff recommends that the applicant prepare a protocol detailing how the air dispersion modeling will be performed; the protocol should be reviewed and approved by appropriate regulatory agencies.

Only air dispersion models approved by the ARB and the United States Environmental Protection Agency (U.S. EPA) should be used.

3. Exposure Assessment

The estimated emission concentrations and identified exposure media are used to establish exposure levels. The applicant must determine the relationship between the exposure levels and incidence of adverse health effects. Algorithms and default values to determine this relationship can be obtained from OEHHA. The applicant may also provide a refined risk assessment based upon data that are more representative of the operations and the conditions unique to the location of the proposed power plant. When a refined risk assessment is prepared, the methods used and assumptions made must be documented and justified.

4. Risk Characterization

In the final step of a risk assessment, the output from the air dispersion modeling is combined with pollutant specific factors called unit risk factors (for cancer effects) or reference exposure levels, for acute and non-cancer health effects. Combining this information will provide an estimate of the potential cancer risk (chances per million) and potential non-cancer impacts expressed as a hazard index. Districts, ARB or OEHHA should be contacted for the most current reference exposure levels. Any potential increases in cancer risk or non-cancer health impacts should be reviewed in context with district risk management policies. According to California Energy Commission staff, typical results from screening analyses performed so far for proposed new power plants are less than one in a million cancer risk and less than one for the ratio of project exposure levels to reference exposure levels for acute and chronic health effects.

VII.

OTHER PERMITTING CONSIDERATIONS

1. OVERVIEW

Power plant permitting in California remains a complex process despite the consolidated California Energy Commission (CEC) power plant siting process, as a major power plant may be subject to myriad of federal, State and local requirements. Complete and enforceable permit conditions governing the design, operation, and maintenance of the proposed power plants serve as valuable compliance tools. This guidance is not intended to be comprehensive. Based on staff's review of recent applications for power plant projects, staff has identified a number of issues that are often difficult to adequately address in a permit. While some general guidance is provided, staff's guidance focuses on the following areas: emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip.

2. GENERAL PERMITTING CONSIDERATIONS

In California, the local air pollution control or air quality management district (district) is responsible for drafting and enforcing the permit conditions needed to ensure that the power plant will comply with **local, State, and federal requirements. Permit conditions should be clearly identified as being applicable to an emission unit or the entire facility. When a requirement is applicable on an emission unit basis, it is important to have permit conditions that adequately address the construction or operation of the affected emission unit. Each permit should contain enforceable conditions to adequately address the following** areas:

- all assumptions and specifications used in the engineering analysis regarding design, operation, performance, and emission limitations used in the technical analysis to establish any emission rate or concentration, or operating parameter;

- any parameter used to evaluate air quality impacts through air quality modeling, such as stack height;

- **the applicant's responsibilities for source testing, emission monitoring, data recording, and reporting; and**
- any specific requirements contained in district rules and regulations and State and federal law.

This guidance does not address requirements of Title IV (the Acid Rain Provisions) and Title V (the federal operating permit program) in the 1990 federal Clean Air Act Amendments. Staff recommends that a district consult its own regulations, the federal Title IV and Title V regulations (Title 40 Code of Federal Regulations (40 CFR) Parts 72 through 77 and Part 70, respectively) for the applicable requirements, and any applicable guidance prepared by the United States Environmental Protection Agency (U.S. EPA).

3. SPECIFIC PERMITTING CONSIDERATIONS

As mentioned previously, this guidance is not entirely comprehensive. The guidance presented here focuses on certain requirements or areas that are often difficult to address in a permit. It is provided to promote consistent and adequate treatment of emission limits, equipment startup and shutdown, source testing and monitoring, fuel sulfur content, and ammonia slip from selective catalytic reduction of oxides of nitrogen (NO_X).

1. Emission Limits

In general, a power plant will be required to comply with emission limits that are derived from prohibitory rules, new source performance standards, control technology requirements (i.e., best available control technology or BACT), and/or mitigation requirements. Permit conditions specifying the emission limits should be expressed in the same form as the underlying regulatory requirement. For example, if a BACT requirement is expressed as an emission concentration measured at a given averaging time and flue gas oxygen content, the permit condition implementing the requirement should utilize the same parameters (i.e., a surrogate hourly or daily limit would not be appropriate in this case). Furthermore, a BACT decision is specific to an individual emission unit or process and should be implemented with permit conditions that are applicable to the affected emission unit, not the facility as a whole. Emission limits implementing control technology requirements should be stated, to the extent feasible, as unit-specific and short-term (i.e., hourly or daily) limits and be enforceable using direct measurement methods.

Emission limits derived from new source review (NSR) and prevention of significant deterioration (PSD) requirements typically need to address both short-term and annual emissions. For example, an air quality impact analysis depends on precise quantification of emissions to model worst-case impacts. When the analysis utilizes less than the potential to emit,[25] the

[25]Potential to Emit is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. (as defined in the 40 CFR 51.165)

emission assumption should be enforceable through an emission limit in the permit; otherwise, the air quality impacts may be underestimated. If short-term emission limits are not evaluated in the ambient air quality impact analysis, then predicted short-term emission limits should be evaluated using the emission levels corresponding to the potential to emit and included in the permit conditions.

While emission offset requirements are typically based on facility-wide emissions, an emission limit on the facility as a whole, or an emission cap, may not be the most appropriate implementation tool; facility-wide emission caps are more difficult to enforce, especially if determination of emissions requires evaluation of extensive records and complex calculations. Ideally, permit conditions should limit annual emissions from each emission unit at the facility. Although combination of the individual emission limits provides the best assurance that the facility will be operated in accordance with the assumptions relied upon when the emission offset requirements were determined, emission caps may be considered to allow greater operational flexibility as long as adequate monitoring is specified.

2. Equipment Startup and Shutdown

With deregulation of the electric utility industry in California, the proposed power plants may need to operate with varying loads and numerous equipment startups and shutdowns. Power plants operated in this manner are known as “merchant plants” that operate in “merchant mode.” Combustion turbines and control equipment do not operate at optimum performance during startup and shutdown due to the changing loads and temperatures. When compared to continuous online operation, merchant mode operation can contribute substantially to the total annual emissions. As a result, ultimate control of emissions can only be achieved by minimizing the emissions during these periods of equipment startup and shutdown. Minimizing emissions is possible by addressing all phases of operation in the BACT decisions and assuring that controls are required and used where feasible. Permit emission limits should be enforceable and written to apply to turbine emissions for all potential loads. Emissions generated during startup and shutdown periods should be regulated by a separate set of limitations to optimize emission control.

To regulate these emissions, permit conditions should required that the power plant operator have a district-approved plan to minimize emissions from equipment startup and shutdown. Permit conditions should limit and require recordkeeping of the number of daily and annual startups and shutdowns. If the turbines are equipped with continuous emission monitors (CEMs), CEMs should be capable of providing duration and quantity of emissions associated with each type of startup and shutdown (cold, warm, hot). When CEMs are not present for a particular pollutant, the permit should be conditioned so that emission projections and limits associated with each type of startup/shutdown are confirmed or enforced, respectively, with source testing where possible. Ideally, permit conditions should require that testing be conducted to establish these emissions prior to commencement of operation, and at least annually thereafter.

3. Source Testing and Monitoring

ARB's goal is to assure that facilities are in compliance with BACT and other emission limits specified in permit conditions. Compliance with BACT an.d other emission limits is most easily verified through CEMs and annual source testing. All source tests should use certified methods that meet the federal, State, and district protocols. A list of approved source test methods is available from the U.S. EPA's website, or the ARB's website.[26] If CEMs are required, source testing should include Relative Accuracy Test Audits (RATA). When CEMs are not used, the district should establish an alternate emission monitoring system to ensure ongoing compliance; an initial source test should establish the relationship between emissions and surrogate parameters which typically include fuel flow rate, flue gas flow rates, flue gas temperature, fuel British thermal unit (Btu) content, revolutions per minute (RPM), load, electrical energy produced, ambient air temperature and pressure, injection rates (if applicable) and other operating parameters. Annual source testing may be used to verify BACT and other emission limits, RATA testing of CEMs and verification of the alternative emission monitoring system, if applicable.

The permit should contain conditions to address the following requirements for source testing:

- pollutants to be tested, operating parameters, frequency of source testing, applicable test methods, parameters to monitor and relationship to emissions, duration of tests, and averaging times;

- for any requirement for CEMs, RATA, quality assurance (QA), and quality control (QC) requirements and procedures;

- for an alternate emission monitoring system, establishment and annual verification of the relationship of emissions to surrogate parameters;

Monitoring should be conducted to verify continual compliance with emission limits. Where feasible, CEMs should be used for measuring NO_X, carbon monoxide (CO), and flue gas oxygen content (O_2). Volatile organic compounds (VOC) can be monitored through correlation with CO CEMs data. Oxides of sulfur (SO_X) emissions can be verified through monitoring of fuel sulfur content. Annual source testing or surrogate parameters are appropriate to determine compliance with the emission limit for particulate matter of ten microns or less (PM_{10}). _Ammonia (NH_3) can be monitored through tracking of NH_3 injection rate and mass balance calculation; compliance with limits during periods between source testing should be monitored with surrogate parameters that limit potential emissions or correlate with emissions. Staff recommends the following list of monitoring methods in descending order of reliability:

[26]The source test methods are approved for Title V compliance monitoring.

- continuous emission monitoring (CEMs),
- source testing along with an alternate emission monitoring system, and
- annual source testing alone.

Concerns have been raised concerning the accuracy of current stationary source test and CEMs methods for measuring gaseous emission levels in the ranges recommended as BACT. ARB staff are currently investigating this low emission level measurement issue and may, if necessary, develop recommendations to ensure accurate and reproducible results in measuring emissions from new power plants.

4. Fuel Sulfur Content

The combustion of fuels containing sulfur results in the emission of SO_X. The quantity of SO_X emitted is directly proportional to the sulfur content of the fuel. SO_X emission levels can be conservatively estimated from the sulfur content of the fuel with mass balance calculations. The SO_X emission levels can be minimized with the use of natural gas as fuel. In determining SO_X emission levels, the calculations should be made with the upper limit of the sulfur content that is specified in the natural gas supplier's contract.

The permit should include the following conditions to address SO_X emission levels:

- a maximum sulfur content (the upper sulfur content limit of the natural gas supplier) and
- monthly monitoring of fuel sulfur content and record keeping requirements (the gas supplier's sulfur content records are acceptable compliance parameters for monitoring of sulfur content.).

5. Ammonia Slip

If selective catalytic reduction is the specified control technology, ammonia will be utilized to convert NO_X to molecular nitrogen (N_2). In converting NO_X to N_2, there is typically some ammonia that does not react and is released out of the stack; this is called ammonia slip. As the health risk assessment of ammonia emissions relies on the ammonia emission levels, permit conditions limiting the ammonia slip are necessary to be health protective.

The permit should include the following conditions to address ammonia slip:

- an emission concentration limit for ammonia, in parts per million volume (ppmv)

with a specified averaging time, along with a limit on the ammonia injection rate;[27]

- monitoring and record keeping requirements;
- a requirement for appropriate calibration procedures to verify ammonia emission levels; and
- a requirement to monitor ammonia emission levels directly or to monitor ammonia injection rates as a surrogate parameter (Correlations between ammonia slip and ammonia injection rate may be established by mass balance analysis or source testing).

[27]As previously stated in Chapter III., staff recommends that districts consider establishing ammonia slip levels at or below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.

APPENDICES

Appendix A:

CALIFORNIA ENERGY COMMISSION
CURRENT AND FUTURE SITING CASES

	Project	Applicant	Size (MW)	Cap. Cost	Location	Filing Date 1/
1	High Desert (97-AFC-1)	Inland & Constellation	720	$350+ million	Victorville, San Bernardino Co.	Jun. 30, 1997
2	Sutter Power (97-AFC-2)	Calpine	500	$300 million	Yuba City area, Sutter County	Dec. 15, 1997
3	Pittsburg (98-AFC-1)	Enron	500	$300 million	Pittsburg, Contra Costa County	Jun. 15, 1998
4	La Paloma (98-AFC-2)	U.S. Generating Co.	1,043	$500 million	McKittrick, Kern County	Aug. 12, 1998
5	Delta Energy (98-AFC-3)	Calpine & Bechtel	880	$400+ million	Pittsburg, Contra Costa Co.	Dec. 18, 1998
6	Sunrise Cogen (98-AFC-4)	Texaco Global Gas & Pwr	320	$250 million	Fellows, Kern County	Dec. 21, 1998
7	Elk Hills (99-AFC-1)	Sempra & Oxy	500	$250 million	Elk Hills, Kern Co.	Feb. 24, 1999
8	Three Mountain (99-AFC-2)	Ogden Power Pacific	500	$300 million	Burney, Shasta Co.	March 3, 1999
9	Metcalf (99-AFC-3)	Calpine & Bechtel	600	$300 million	Santa Clara Co.	April 30,1999
10	Moss Land Repwr (99-AFC-4)	Duke Energy	1,206	$500 million	Moss Landing, Monterey Co	May 7, 1999
11	Morro Bay Repower 2/	Duke Energy	530	$250 million	Morro Bay, San Luis Obispo Co.	July 1999
12	Otay Mesa 2/	U.S. Generating Co.	1,050	$500 million	Otay Mesa, San Diego Co.	July 1999
13	Midway-Sunset 2/	ARCO Western Energy	500	$300 million	Kern Co.	July 1999
14	Combined Cycle 3/		500	$300 million	Imperial. Co.	July 1999
15	Antelope Valley 2/	AES	1000	$500 million	California City, Kern Co.	July 1999
16	Combined Cycle 3/		1000	$500 million	Los Angeles Co.	Aug. 1999
17	Combined Cycle 3/		1000	$500 million	Orange Co.	Aug. 1999
18	Newark 2/	Calpine & Bechtel	600	$300 million	Alameda Co.	Aug. 1999
19	Blythe Energy 2/	Summit Energy Group	400	$250 million	Blythe, Riverside Co.	Aug. 1999
20	South City 2/	AES	550	$300 million	So. San Francisco, San Mateo Co.	Aug. 1999
21	Long Beach 2/	Enron	500	$300 million	Long Beach, LA Co.	Aug. 1999
22	Sunlaw 2/	Sunlaw Cogen Partners I	800	$450 million	Vernon, LA Co.	Sep. 1999
23	Pastoria 2/	Tejon Ranch	960	$300 million	Kern County	Oct. 1999
24	Combined Cycle 3/		500?	$300 million?	San Bernardino Co.	Nov. 1999
25	Combined Cycle 3/		120	$75 million	San Bernardino Co.	Feb. 2000
26	Combined Cycle 3/		500?	$300 million?	Los Angeles Co.	Mar. 2000
27	Combined Cycle 3/		500?	$300 million?	San Bernardino Co.	May 2000
28	Combined Cycle 3/		500	$300 million	San Bernardino County	May 2000
29	Combined Cycle 3/		400	$250 million	Kern County	June 2000
30	Combined Cycle 3/		400	$250 million	Kern County	June 2000
32	Combined Cycle 3/		500	$300 million	Yuba County	Sept. 2000
31	Combined Cycle 3/		500	$300 million	S.F. Bay Area	Dec. 2000
33	Combined Cycle 3/		500	$300 million	S.F. Bay Area	Dec. 2000
34	Combined Cycle 3/		500	$300 million	San Diego County	June 2001
35	Combined Cycle 3/		1500	$700 million	San Diego County	Dec. 2001

Notes:
1/Staff's expected filing date.

2/Project has been publicly announced.
3/Project is not publicly disclosed; working with potential applicant.

Source: California Energy Commission Staff. Revised 5/12/99

Appendix B:

GUIDANCE ON THE PROCEDURE FOR MAKING A BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION

1. OVERVIEW

Federal regulations found in Parts 51 and 52 of Title 40 Code of Federal Regulations (40 CFR Parts 51 and 52) specify that one of two levels of emission control will apply to a new, or modified, stationary source of criteria pollutants subject to major source permitting requirements. The control requirements are pollutant specific and depend on an area's attainment status for the ambient air quality standards; a district may have an attainment designation for some pollutants and a nonattainment designation for other pollutants. The more stringent federal requirement is termed "lowest achievable emission rate (LAER)" and is required when an area is nonattainment for a standard; the less stringent federal requirement is termed "best available control technology (BACT)" and is required when an area is in attainment, or has an "unclassified" designation, for a standard. However, local air pollution control and air quality management districts (districts) in California use the term, "best available control technology (BACT)" exclusively when referring to the emission control requirements of their New Source Review (NSR) permitting programs. With a few exceptions, the district definitions of BACT are based on the more stringent of the two federal emission control requirements.[1]

Unless otherwise indicated, the use of the term "best available control technology (BACT)" in this document will refer to the emission control requirements in California as defined in a district's NSR permitting program regulation, often referred to as "California BACT." With some variation, the districts' BACT definitions generally share the following elements/provisions:

- BACT is determined for a given "class or category of source;"

- BACT is generally specified as the most stringent emission level of these three alternative minimum requirements:
  - the most effective control achieved in practice,
  - the most stringent emission control contained in any approved State Implementation Plan (SIP),
  - any more stringent emission control technique found by the district to be both technologically feasible and cost effective; and

[1]In certain districts with attainment, or unclassified, designations for the ambient air quality standards, the BACT definition may be more similar to the less stringent federal requirement.

- BACT emission limits must not be less stringent than a New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or any other applicable federal, State, or district requirement.

As part of the NSR process, the district must review an applicant's proposed BACT for the project's emission sources. The BACT determination must be consistent with the district's BACT definition and is a demonstration that the emission source will be constructed, or modified, in such a manner that its operation will release the least amount of air pollutants possible. District permitting programs and the California Energy Commission power plant siting process provide opportunity for the Air Resources Board (ARB), United States Environmental Protection Agency (U.S. EPA), and public interest groups to provide input in the BACT decision process.

Following is a discussion of the generalized procedure for making a BACT determination.[2] A summary of a technical review of previous BACT determinations for power plant combustion turbines using natural gas is contained in Chapter III of ARB's "Guidance for Power Plant Siting and Best Available Control Technology." The technical review which is the basis for the Chapter III summary is contained in Appendix C. The technical review examines, in detail, the various control equipment and performance that have been achieved in practice or are technologically feasible.

B. DESCRIPTION OF A GENERALIZED PROCEDURE FOR DETERMINING BEST AVAILABLE CONTROL TECHNOLOGY

BACT determinations typically involve a methodical analysis of the applicable district's BACT definition, and past and recent BACT determinations. In this section, the generalized procedure is described for determining BACT. This generalized procedure reflects the common elements/provisions of district BACT definitions and consists of the following steps:
1) establishment of the "class or category of source," 2) determination of "achieved in practice levels," 3) evaluation of control measures and implementing rules and regulations contained in State Implementation Plans (SIPs), 4) identification of control technologies that are more

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[2]This procedure does not provide for the consideration of economic, energy, and environmental impacts; however, district BACT definitions based on the less stringent federal Best Available Control Technology definition found in **Section 169(3) of Part C of Title I of the federal Clean Air Act** provide for the consideration of economic, energy, and environmental impacts.

stringent than what has been "achieved in practice," and 5) the determination of BACT.

As the requirement for BACT is pollutant specific, the following generalized procedure should be repeated for each pollutant for which a proposed project's emissions will exceed BACT requirement thresholds. Also, when evaluating the information collected during each step of the generalized procedure, it may be necessary in some cases to reconsider the conclusions made at a previous step (i.e., one may need to repeat previous steps). For example, the "class or category of source" established in step one may be found to be overly broad, or narrow, after evaluation of information collected in latter steps.

Step 1. Establishing the "Class or Category of Source"

The effort to determine BACT begins with the establishment of the "class or category of source." The "class or category of source" establishes the scope of evaluations for the subsequent steps involving evaluations of control requirements. BACT determinations should be consistent within a "class or category of source."

"Class or category of source" provides the scope of what other basic equipment (or sources) will be used as comparables. The term "class or category of source" is not explicitly defined in federal, State, or district rules and regulations. As a practical matter, a power plant's basic equipment, processes, and energy sources (fuel) should be considered when establishing "class or category of source." Equipment or processes of similar type or function are typically placed together in a "class or category of source." Different makes (manufacturers) or models of the same type of basic equipment (e.g., a combustion turbine) generally should not be a consideration in establishing "class or category of source." However, the function and capacity of the basic equipment may be a consideration. It is noteworthy that the U.S. EPA has a technology transfer policy that broadens a "class or category of source" to include any sources with similar exhaust gas streams that could be controlled by the same or similar technology or any similar, but not necessarily identical, processes (e.g., similar coating operations).[3]

The establishment of an appropriate "class or category of source" is an important step; an appropriate selection will promote consistent BACT decisions that will help ensure that only the cleanest projects are approved. When the "class or category of source" that is otherwise applicable for a proposed project appears to be overly broad, the applicant has the burden of providing a demonstration to justify a narrower "class or category of source." For example, gas turbines may be considered a "class or category of source." Alternatively, one may want to

[3]August 29, 1998, U.S. EPA Memorandum entitled, "Transfer of Technology in Determining Lowest Achievable Emission Rate (LAER)," from John Calcagni, Director of Air Quality Management Division, to David Kee, Director of Air and Radiation Division, Region V.

consider gas turbines fired on natural gas and gas turbines fired on oil as two different "classes or categories of source." Commonly, the "class or category of source" may have been restricted to account for differences in technological feasibility and performance of control equipment due to the size of the basic emitting equipment. In this case, the applicant would need to demonstrate to the district that there are changes in control efficiency, lack of demonstrated use, inability to obtain financing, or restrictive conditions of vendor guarantees or warranties, etc. that make the control technology infeasible. ARB staff does not consider lack of vendor guarantees or warranties alone to be sufficient justification for altering a "class or category of source" determination.

Step 2. Establishing the "Achieved In Practice" Emission Control Level

This step identifies what emission limitation or control technology is the most stringent control level that has been achieved in practice for a relevant "class or category of source." This step involves a review of past, and recent, performance of controls on other equipment units in the same "class or category of source." The emission levels achieved with the various controls are compared and ranked to determine which control is the most stringent. Emission concentrations, normalized emissions rates (e.g., lb per Btu) and/or technology-specific requirements should be used to compare the performance of the required controls. Averaging times for emission measurement may be a factor in comparing the emission levels.

There are several sources of information on past BACT determinations. BACT determinations are cataloged in the clearinghouses maintained by the California Air Pollution Officers Association (CAPCOA) and the U.S. EPA.[4] In California, several districts, including the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Unified Air Pollution Control District, have BACT guidance documents. However, the SCAQMD intends to discontinue use of its guidance document and begin maintaining its own clearinghouse.

Step 3. Rules Or Regulations Contained In Any Approved State Implementation Plan

[4]The CAPCOA and U. S. EPA RACT/BACT/LAER clearinghouses are available on the Internet at www.arb.ca.gov/bact/bact.htm and at mapsweb.rtpnc.epa.gov/RBLCWEB/b102.htm, respectively.

Typically, a BACT emission limitation must be at least as stringent as any control measure that is contained in any approved State Implementation Plan (SIP) that is applicable to the "class or category of source." For example, a district may have a rule specifically limiting emissions from stationary gas turbines, or more general rules restricting opacity or fuel sulfur content from any emission source required to obtain a permit. The BACT emission limitation should not be less stringent or cause a violation of any of these applicable SIP-approved rules and regulations. Therefore, this step involves evaluation of the rules and regulations of all California districts as well as the rules and regulations of other states that may apply to emission sources within the same "class or category of source." Rules and regulations for California districts are available from the ARB website. Rules and regulations for other states can be found at the U.S. EPA's RACT/BACT/LAER Clearinghouse website, individual state websites, or by contacting each state directly.[5]

Step 4. Control Technologies More Stringent Than Tho se Achieved In Practice

Most districts in California are required to consider more stringent control technologies than those that are achieved in practice. The more stringent controls must be both technologically feasible and cost effective. Where more than one such control exists, staff suggests that the U.S. EPA's "top-down," decision-making procedures be used to rank the controls.[6] Staff recommends that the district rank technologically feasible controls by stringency of emission control after making the following determinations or demonstrations:

- determine the technologies that are technologically achievable using data from prototype testing, utilization with another "class or category of source," or limited operation not meeting achieved in practice criteria;
- determine the economic feasibility of each of the technologies identified above with a cost-effectiveness analysis;
- determine if the cost effectiveness is within the cost effectiveness limits of current BACT requirements or predetermined cost-effectiveness criteria established by the district; and

[5]A listing of state air quality office contact information is available on the U.S. EPA website at www.epa.gov/ttn/uatw/saq_offices.htm.

[6]See previous footnote 3.

- rank the cost-effective control technologies from the most to least stringent.

Step 5. Making The BACT Decision

In the final step of the generalized procedure, a BACT decision is made. The BACT decision must be consistent with the provisions of the district's BACT definition including the requirement that the BACT emission limit must not be less stringent than an applicable NSPS or NESHAP. In most cases, the BACT decision will be based on the most stringent emission level of the following three alternative minimum requirements identified in earlier steps:

- the most effective control achieved in practice identified (See Step 2.),

- the most stringent emission control contained in any approved SIP (See Step 3.), or

- any more stringent emission control technique found by the district to be both technologically feasible and cost effective (See Step 4.).

Appendix C:

SUPPORTING MATERIAL FOR BACT REVIEW FOR LARGE GAS TURBINES USED IN ELECTRIC POWER PRODUCTION

1. INTRODUCTION

This technical appendix provides the basis for the best available control technology (BACT) information presented in Chapter III of the Air Resources Board's (ARB or Board) Guidance for Power Plant Siting and Best Available Control Technology. The appendix covers control methods for oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC)[1], particulate matter of ten microns or less (PM_{10}), and oxides of sulfur (SO_X) emissions. Furthermore, it is intended to provide information to be used in determining BACT for stationary, natural gas-fired turbines (herein referred to as "gas turbines") used in electric power production of at least 50 megawatts (MW) in size.

It is the responsibility of the permitting agency to make its own BACT determination for the "class or category of source" of gas turbine application. Some factors that should be considered in determining gas turbine "class or category of source" are load variability, manned versus remote control, and catalyst compatibility with flue gas characteristics. The latter concern makes it necessary to consider BACT for simple-cycle configurations separately from combined-cycle and cogeneration configurations, at least for NO_X, CO, and VOC.

In evaluating BACT for gas turbines, staff reviewed control technologies and corresponding emission levels for each pollutant in the areas of:

- current State Implementation Plan (SIP) control measures,
- control techniques required as BACT,
- emission levels achieved in practice, and
- more stringent control techniques which are technologically and economically feasible but are not yet achieved in practice.

Information in these four areas was obtained primarily from California air quality management and air pollution control district (district) rules, personal contacts with California and out-of-state

[1]Regulatory agencies use varying terminology for volatile organic compounds. Some common terms to mention include: reactive organic gases (ROG), non-methane hydrocarbons (NMHC), and precursor organic compounds (POC).

regulatory agency staff, consultants, basic equipment vendors, control technology vendors, and proposed and existing power plant operators and proponents. In addition, BACT determinations listed in the California Air Pollution Control Officers Association (CAPCOA) BACT Clearinghouse and U.S. EPA RACT/BACT/LAER Clearinghouse were reviewed. Staff's review of the Clearinghouse BACT determinations was limited to gas turbines of approximately 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations. The information gathered from these avenues was used in recommending the proposed BACT emission levels.

A layout showing major process equipment for a typical stationary gas turbine combined-cycle power plant is provided in Figure 1 for reference purposes. A listing of acronyms and abbreviations used in Appendix C is included at the end of the appendix.

II. POTENTIAL METHODS OF NO_X EMISSION CONTROL

Traditionally, the pollutant of most concern from gas turbines is NO_X. NO_X emissions are of particular concern due to their contribution to ground-level ozone formation, stratospheric ozone depletion, and acid rain. In the lower atmosphere, NO_X combines with reactive organic gases in the presence of sunlight to form ground-level ozone, which is the primary component of urban smog. In addition, nitric oxide and nitrogen dioxide are components of acid rain. These nitrogen oxides rise into the atmosphere and are oxidized in clouds to form nitric acid.

A. NO_X Formation Mechanisms

NO_X collectively refers to the combustion products nitric oxide (NO) and nitrogen dioxide (NO_2). NO_X emissions from fossil fuel combustion originate in three primary ways: from fuel-bound nitrogen, as prompt NO_X, and as thermal NO_X. NO_X from fuel-bound nitrogen is important in some liquid and solid fuels, but is minimal in gaseous fuels. Fuel NO_X is formed from the nitrogen bound in the fuel of combustion. NO_X is created when the fuel molecule is oxidized, releasing the reactive nitrogen. Prompt NO_X is a component of thermal NO_X formed at the combustion flame front (promptly) from early reactions of fuel-derived nitrogen intermediaries and hydrocarbon radicals during combustion. Prompt NO_X is recognized to be a minor component of total NO_X and is independent of combustion temperature. The most abundant means of NO_X production, especially for internal combustion, is thermal-induced NO_X. Thermal NO_X is created by high temperatures in the presence of free oxygen. The proportion of thermally induced NO_X is even greater when combusting gaseous fuels.

Atmospheric conditions which affect NO_X emissions are humidity, temperature, and pressure. Atmospheric water vapor has a quenching effect; the energy required to heat the airborne water has a tendency to lower combustor temperatures. At low humidity, NO_X emissions increase with increasing temperature. At high humidity, the effect of temperature is varied; NO_X emissions decrease with increasing ambient temperature above 50 °F, and increase with increasing temperature within the range below 50 °F. Increased atmospheric pressure results

in higher pressure and temperature levels within the combustor, so NO_X emissions increase.

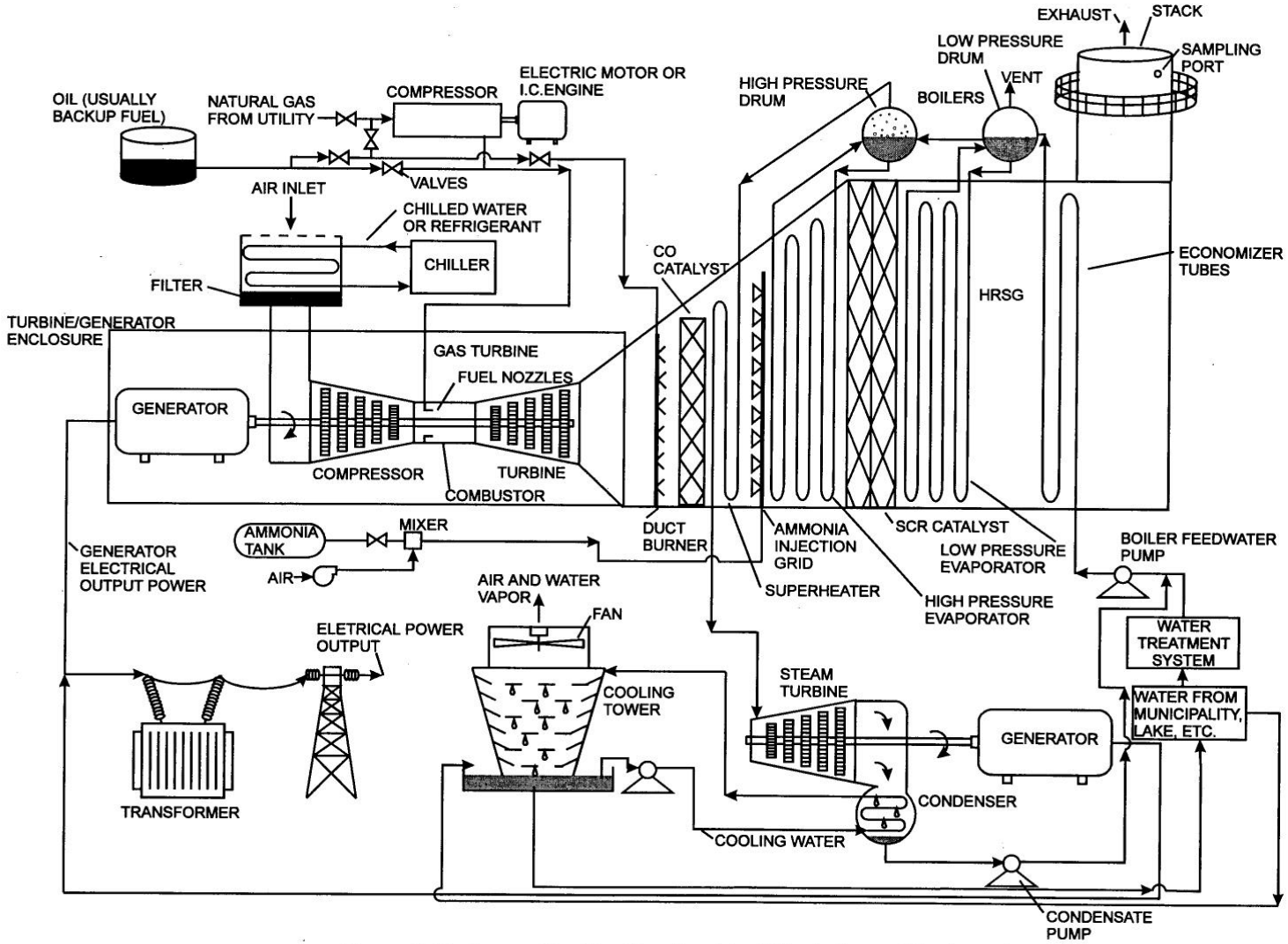

Figure 1 Stationary Gas Turbine Combined-Cycle Power Plant

There is a direct relationship between the power output level of a gas turbine, the firing temperature, and the combustor flame temperature. Gas turbines each have a base-rated power output level with corresponding NO_X emissions. At power outputs below base-rated power, flame temperatures are lower and thus NO_X emissions are lower. However at peak power outputs, NO_X emissions are greater due to increased flame temperatures.

B. Gas Turbine Combustor NO_X Controls

Combustion modifications reduce the concentration of NO_X emissions in the gas turbine flue gas by decreasing combustion temperature or decreasing the quantity of oxygen available for combustion.

1. Diluent Injection

Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. However, the higher the gas turbine inlet temperature, the more NO_X that is produced. Diluent injection, or wet controls, can be used to reduce NO_X emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_X emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_X forming regions of the combustor. Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control).

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Nonuniform mixing of water and fuel creates localized "hot spots" in the combustor that generate NO_X emissions. Increased NO_X emissions require more diluent injection to meet a specified level of emissions. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Water is a better heat sink than steam; therefore more steam is required to reach a particular level of NO_X emissions. However, newer gas turbines usually apply steam injection. Steam injection is generally a better alternative since it does not increase the heat rate as much as water, carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe, and maintenance is reduced.

A negative attribute of water or steam injection is that the water or steam must be very pure before injection into the turbine. Any contaminants in the water or steam will cause a buildup of deposits on the turbine blades and other equipment. Deposits on the gas turbine blades reduce turbine efficiency, increase down time for maintenance, and can lead to failure of the equipment in extreme circumstances.

2. Dry Low-NO_X Combustors

The combustion chamber, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long can, an axially-centered ring of long cans (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_X. In contrast, dry low-NO_X combustors minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_X formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame. Dry low-NO_X combustors can achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

To achieve low NO_X emission levels, the mixture of fuel and air introduced into the combustor (e.g., air/fuel ratio) must be maintained near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this air/fuel ratio at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that occur as the air/fuel ratio reaches the lean flammability limit, lean premixed combustors switch to diffusion combustion mode at reduced load conditions. This switch to diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled.

3. Catalytic Combustion

In catalytic combustion, a catalyst is used to promote oxidation of the inlet gas stream at lower temperatures than are required in standard thermal combustion. The catalyst bed is used to oxidize a lean air/fuel mixture within the combustor instead of burning it with a flame, as in a conventional combustor. The catalyst limits the temperature in the combustor and helps to stave off the production of thermal NO_X. Catalytic combustion can achieve NO_X emission of about 3 ppmvd NO_X at 15 percent oxygen (approximately 98 percent control), as claimed by manufacturers.

3. Duct-Burner NO_X Controls

1. Duct Burner Operation

Combined-cycle and cogeneration power plants are equipped with heat recovery steam generators (HRSG) to extract more energy from the hot exhaust gases leaving the gas turbine and create steam for use in other industrial processes or to turn a steam turbine to generate electricity. Feed water pumps send water through heat exchangers in the HRSG. The heat exchangers are generally large tubes made of conductive metals. Hot gases exchange heat energy with the water in the tubes before exiting through the stack. Duct burners can be used to increase the steam capacity of the HRSG. The duct burners are installed at the front of the HRSG to supply additional heat to the flue gas exiting the gas turbine. Because the duct burners are fuel-fired, they will produce NO_X emissions in addition to those from combustion in the gas turbine.

2. Low-NO_X Burners

Low-NO_X burners reduce NO_X by completing the combustion process in stages. Staged combustion can achieve lower NO_X emissions by dividing the combustion process into a number of stages where the air to fuel ratio is varied to reduce NO_X formation. This staging partially delays the combustion process and results in a cooler flame that suppresses thermal NO_X formation. After the initial combustion zone where the fuel is ignited, a pyrolitic zone is formed where the fuel is chemically broken down by heat from the flame. In the next stage, a fuel-rich (oxygen lean) zone is formed which limits the formation of NO_X. The last stage consists of a burnout zone where completion of combustion occurs.

The configuration of combined-cycle and cogeneration power plants is such that the gas turbine and duct burner exhaust through a common stack. Therefore, NO_X emissions from the duct burner are also further reduced with add-on controls which are otherwise utilized to reduce NO_X emissions from the gas turbine. Staff is not aware of any source test data attributing individual emission control efficiency to low-NO_X burners as part of the overall control of NO_X emissions from a gas turbine with a HRSG.

D. Flue-Gas NO_X Controls

1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface of the catalyst to form molecular nitrogen (N_2) and water. The primary chemical reactions are shown below.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configurations, and into the HRSG portion of the gas turbine downstream of the superheater in combined-cycle and cogeneration configurations.

In honeycomb-type catalysts, the size of the catalyst openings (i.e., pitch) is important. Smaller pitch equates to larger surface area, and thus greater NO_X removal efficiency due to maximizing of the surface area on which the reactions take place. At the other extreme, if catalyst openings are too small, potential for clogging from contaminants becomes an issue. The residence time of the exhaust gases in the presence of the catalyst must be sufficient for the reactions to take place. The longer the exposure time of the exhaust with the catalyst, the greater the NO_X removal is. Residence time is defined as the volume of the catalyst (e.g., ft^3) divided by the exhaust flow rate (ft^3/min). Space velocity is the inverse of residence time. Efficient NO_X removal is usually indicated by a space velocity of approximately 30,000 per hour.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 600 to 800 °F. Keeping the exhaust gas temperature within this range is important. If it drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature gets too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1000 °F. HRSG cool the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam for use in other industrial processes or to turn a steam turbine. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (e.g., zeolite) which can operate at temperatures up to 1100 °F, are an option. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of about 80 to 95 percent.

a. Ammonia By-Product Emissions

Selective catalytic reduction uses ammonia as a reducing agent in controlling NO_X emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. Currently, ammonia is not regulated by district new source review rules. New source review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient PM_{10} concentrations, it is not listed in any California new source review rule as a precursor to PM_{10}. As a result districts have regulated ammonia since the mid-1980's under nuisance and toxic air contaminant rules. The only exception is in the South Coast Air Quality Management District, where ammonia is specifically regulated under a new source review rule.

i. Regulation as a Toxic Substance

Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. However, due to acute and chronic non-cancer health effects, ammonia is potentially regulated under district risk management programs. Such programs may include toxic new source review rules/policies and the requirements of the Air Toxics "Hot Spots" Program (Section 44360 *et seq.* of the Health and Safety Code). Ammonia is listed under the "Hot Spots" Program, and therefore, sources are required to report the quantity of ammonia they routinely release into the air. Gas turbines using selective catalytic reduction typically have been limited to 10 ppmvd at 15 percent oxygen ammonia slip; however levels as low as 2 ppmvd at 15 percent oxygen have been proposed and guaranteed by control vendors. Ammonia slip should be limited to at least the extent that the risk from ammonia emissions is within acceptable risk exposure levels.

ii. Regulation as a $PM_{2.5}$ Precursor

Ambient particulate matter less than 2.5 microns ($PM_{2.5}$) is composed of a mixture of particles directly emitted into the air and particles formed in air from the chemical transformation of gaseous pollutants (secondary particles). Principle types of secondary particles are ammonium sulfate and ammonium nitrate formed in air from gaseous emissions of sulfur oxides and NO_X, reacting with ammonia. Studies conducted in the South Coast Air Basin by Glen Cass of Caltech have indicated that ammonia is a primary component in secondary particulate matter. As a result, districts should consider the impact of ammonia slip on meeting and maintaining PM_{10} and $PM_{2.5}$ standards. Where a significant impact is identified, districts should revise their respective new source review rules to regulate ammonia as a precursor to both PM_{10} and $PM_{2.5}$.

2. SCONOx

The SCONOx system, developed by Goal Line Environmental Technologies, uses a catalyst to remove NO_X emissions by oxidizing NO to NO_2. The NO_X is absorbed onto the catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates which are deposited onto the catalyst surface. SCONOx does not use ammonia; therefore there are no ammonia emissions from this catalyst system. The reactions are shown below.

$$NO + \tfrac{1}{2} O_2 \rightarrow NO_2$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The optimal temperature window for operation of the SCONOx catalyst is from 280 to 700 °F. Therefore, the catalyst is not applicable to simple-cycle configurations unless heat is recovered from the exhaust gas (see discussion in next section). Operating data from Federal Cogeneration in Los Angeles County, California, indicates SCONOx can achieve an emission level of 2.0 ppmvd NO_X at 15 percent oxygen (approximately 98.6 percent control).

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NO_X can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and molecular nitrogen. Carbon dioxide in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst.

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O_{(g)} + N_2$$

The regeneration gas is produced by reacting natural gas with oxygen from ambient air. A gas generator uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The mixture is diluted to under 4 percent hydrogen using steam.

The SCONOx catalyst is designed to be installed downstream of the gas turbine after the HRSG; whereas the selective catalytic reduction catalyst is installed within the HRSG in combined-cycle and cogeneration power plant configurations. Therefore, SCONOx may be a good option for retrofits of combined-cycle and cogeneration power plants because the catalyst can be added at the back of the HRSG without the major modification to the HRSG that would be required for selective catalytic reduction.

3. Exhaust Temperature Considerations

The efficiency of some NO_X controls is limited by temperature. This is especially true of catalytic controls. Catalytic control efficiencies may be reduced at hot or cold temperatures. For example, hot temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, low temperatures can result in higher NO_X emissions due to the fact that catalysts normally require a minimum temperature before they become chemically active.

Flue gas temperatures associated with simple-cycle gas turbines are generally higher than those of gas turbines used in combined-cycle and cogeneration operations. Simple-cycle gas turbines can have exhaust temperatures ranging up to and around 1100 °F, which vary only slightly from the gas turbine to the stack. With combined-cycle and cogeneration gas turbines, exhaust heat is removed with a HRSG, resulting in a decrease in flue gas temperatures (e.g., 1050 °F) from the gas turbine to the stack (e.g., 350 °F). Catalysts used for selective catalytic reduction are not as efficient in controlling NO_X at the higher temperatures associated with the uncooled exhaust of simple-cycle gas turbines. As a result, gas turbine emissions from combined-cycle and cogeneration operations can be controlled with more efficiency.

Staff is aware that, in general, aeroderived gas turbines have lower exhaust temperatures than industrial frame gas turbines, which has implications toward simple-cycle power plant configurations. For example, General Electric LM-series aeroderived gas turbines have exhaust temperatures ranging from approximately 752 to 974 °F. General Electric industrial-frame series gas turbines have exhaust temperatures ranging from approximately 909 to 1129 °F.[2] Therefore, it appears that where aeroderived gas turbines are proposed for simple-cycle power plants, high temperature catalytic control systems are feasible options and should perform at a control efficiency level near that of catalysts used in combined-cycle and cogeneration power plants. However, where industrial frame gas turbines are applied in simple-cycle power plants, the high exhaust temperatures approaching 1100 °F may require case-by-case evaluation regarding the feasiblity of NO_X control through selective catalytic reduction. Recognizing that catalysts must be restructured to deal with high temperatures, more operational problems may be encountered in consistently achieving the required emission levels due to the deactivation of the catalyst.

[2]Gas Turbine World 1997 Handbook, Volume 18.

E. Current SIP Control Measures

There are several State Implementation Plan (SIP) control measures that have been applied to the control of NO_X emissions from gas turbines. The most stringent of these control measures has been adopted in California by the South Coast Air Quality Management District (SCAQMD) with NO_X emission standards based on size, annual operating hours, and control systems employed. The most stringent NO_X requirements are as follows: 25 parts per million by volume dry (ppmvd) at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines from 0.3 to under 2.9 MW, 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 2.9 MW but less than 10 MW, and 9 ppmvd at 15 percent oxygen averaged over 15 consecutive minutes for gas turbines of at least 10 MW employing selective catalytic reduction.[3] The control measure provides exemptions from the NO_X standards for certain units.[4] These SIP control measures have been adopted to comply with air quality goals of the California Clean Air Act of 1988 and meet a level of stringency referred to as Best Available Retrofit Control Technology (BARCT). BARCT is slightly more stringent than similar control measures required for the Federal Clean Air Act, which are referred to as Reasonably Available Control Technology (RACT). California district stationary gas turbine rules are available on the ARB's website at www.arb.ca.gov/html/drdb.htm.

F. Control Techniques Required as BACT

Tables C-1 and C-2 list the most stringent NO_X emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

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[3]SCAQMD rule provides for adjustment of emission limits based on the demonstrated percent efficiency of the gas turbine unit. These numbers are based on a minimum 25% efficiency.

[4]Exemptions are generally provided for laboratory units, units used only for firefighting or flood control, emergency standby units, units under 4 MW with limited annual hours of operation, and during startup and shutdown. Exemptions do not preempt the units from all rule requirements. The exemptions are primarily intended to indicate exemptions from emission limit requirements.

Table C-1: NO_X Emission Controls Required for Simple-Cycle Power Plant Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine generator set producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 and 7.33 lb/hr (3-hr average) and 175.8 lb/day	20 ppmvd @ 15% O_2
Sacramento Cogeneration Authority (Proctor & Gamble) 421.4 MMBtu/hr General Electric LM6000 gas turbine generator set producing 25.24 MW	A/C: 11436 Issued: 8/19/94 Startup: not built yet	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbine generator sets	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Water injection	25 ppmvd @ 15% O_2 and 158 lb/hr and 0.084 lb/MMBrtu	Not applicable
Northern California Power Agency 325 MMBtu/hr General Electric MS 5001P "Frame 5" gas turbine generator set producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Water injection	42 ppmvd @ 15% O_2	Not applicable

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Sutter Power Plant Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and steam turbine producing 160 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Dry low-NO_X combustors + selective catalytic reduction	2.5 ppmvd @ 15% O_2 (1-hr average)	10 ppmvd @ 15% O_2
Sacramento Power Authority	A/C: 11456	Water injection	3 ppmvd @	10 ppmvd @

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
(Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbines with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Issued: 8/19/94 P/O: 13629 Startup: 1997	+ selective catalytic reduction	15% O_2 (3-hr average)	15% O_2
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	A/C: 2-6101-00185 Issued: 6/6/95 P/O: 2-6101-00185 Issued: 11/12/97	Dry low-NO_X combustors + selective catalytic reduction	3.5 ppmvd @ 15% O_2 (1-hr average)	10.0 ppmvd @ 15% O_2
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	A/C: N-3233-1-0 Issued: 3/16/94 P/O: N-3233-1-0 Issued: 7/21/95	Steam injection + selective catalytic reduction	3.5 ppmvd @ 15% O_2 (3-hr average)	25.0 ppmvd @ 15% O_2
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine and HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Steam injection + selective catalytic reduction	3.6 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2
Hermiston Generating Company Two 1,696 MMBtu/hr General Electric Frame 7FA gas turbines with HRSG (no duct burners)	A/C: 30-0113 Issued: 7/7/94 P/O: 30-0113 Startup: 3/28/96	Selective catalytic reduction	4.5 ppmvd @ 15% O_2	Not available
Portland General Electric Company Two 1,720 MMBtu/hr General Electric Frame 7FA gas turbine generator sets with HRSG.	A/C: 25-0031 Issued: 5/31/94 P/O: 25-0031 Startup: 11/1/95	Dry low-NO_X combustors + selective catalytic reduction	4.5 ppmvd @ 15% O_2 (24-hr average)	Not available
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Low-NO_X duct burner and Dry low-NO_X combustors + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	10 ppmvd @ 15% O_2

Table C-2: NO_X Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of NO_X Control	Emission Limits	Ammonia Slip Limit
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Water injection + selective catalytic reduction	5 ppmvd @ 15% O_2 (3-hr average)	20 ppmvd @ 15% O_2

G. Emission Levels Achieved in Practice

Tables C-3 and C-4 list the most stringent NO_X emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas.

Table C-3: NO_X Emission Source Test Results for Simple-Cycle Gas Turbines		
Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Water injection + selective catalytic reduction	4.72 ppmvd @ 15% O_2 in Sep-Oct 1995
		3.95 ppmvd @ 15% O_2 in Nov 1996
		3.96 ppmvd @ 15% O_2 in Nov 1997-Jan 1998
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	Water injection	37.58 ppmvd @ 15% O_2 in May 1997

Table C-4: NO_X Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines		
Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Brooklyn Navy Yard Cogeneration	Dry low-NO_X combustors +	2.2 ppmvd and 1.8 ppmvd @ 15% O_2

Table C-4: NO_X Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of NO_X Control	Measured Emissions
Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	selective catalytic reduction	in 1996 startup source test
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	Low-NO_X duct burner and Dry low-NO_X combustors + selective catalytic reduction	4.31 ppmvd @ 15% O_2 in Jun 1997
		3.27 ppmvd @ 15% O_2 in Jun 1998
Federal Cold Storage Cogeneration 222.2 MMBtu/hr General Electric LM2500-M-2 gas turbine and steam turbine producing 32 MW	Water injection + SCONOx catalyst	2.0 ppmvd @ 15% O_2 with 6 months (Jun-Dec 1997) CEMs data analysis
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	Steam injection + selective catalytic reduction	2.25 ppmvd @ 15% O_2 in 1996
		2.97 ppmvd @ 15% O_2 in 1997
		2.5 ppmvd @ 15% O in 1998
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Water injection + selective catalytic reduction	2.47 ppmvd @ 15% O in Oct 1997
		2.39 ppmvd @ 15% O_2 in Oct 1998

H. More Stringent Control Techniques

1. Technologically Feasible Controls

a. Lower NO_X Emission Levels Using Tandem Approach

There are three basic types of NO_X emission controls employed to gas turbines: wet controls using water or steam injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation, and post-combustion controls to reduce NO_X formed in the turbine. While each type of control results in a particular level of NO_X emissions, the potential for reducing NO_X emissions down to single-digit values and fractions thereof can be achieved by applying a tandem approach, using controls in combination to reduce NO_X. Common NO_X control combinations currently in use include water or steam injection with selective catalytic reduction, dry low-NO_X combustors with selective catalytic reduction, and water injection with SCONOx. Where present, there is also the potential to control NO_X from duct burners through burner combustion controls. The combination of duct burner, gas turbine combustion, and add-on controls has the potential to reduce NO_X emissions to levels more stringent than what has currently been achieved in practice.

b. Scale-up and Lower Emission Levels with SCONOx

Deregulation of the electric utility industry in the New England area of the United States has, like California, brought about an increase in the number of proposed power plant projects. Fifteen such projects are currently proposed in the Commonwealth of Massachusetts. The Massachusetts Department of Environmental Protection (MDEP), in a January 29, 1999, memorandum from David Struhs, recognizes that technologies are commercially available that can achieve a BACT/LAER emission level of 2.0 ppmvd NO_X at 15 percent oxygen. Also, due to MDEP approval of a 5 MW combined-cycle power plant at the Genetics Institute in Andover, Massachusetts, using a dry low-NO_X combustor with SCONOx, MDEP will require a zero ammonia emission rate for all power generation units 50 MW or less. Eventually, MDEP's goal is to establish a zero ammonia emission rate for power plants generating 50 MW or more.

The basis for requiring zero ammonia in addition to the 2.0 ppmvd NO_X level is contained in the Northeast States for Coordinated Air Use Management (NESCAUM) BACT Guideline (June 1991). The guideline states that "where approximately the same degree of emission reduction can be achieved by different technologies, preference should be given to the technology that achieves the reduction with the greatest degree of pollution prevention."

Due to liability issues associated with merchant mode operation, power plant project proponents are demanding that the power plant gas turbine supplier bear liquidated damages if a power plant fails to attain its promised level of availability. In order to justify liability assumption for a control system's potential impact on plant performance, a high degree of confidence in the technology is required. Without an extensive track record of performance on a large gas turbine,

ABB Environmental Systems Division (SCONOx licensee for systems over 100 MW) is reluctant to guarantee that the technology will meet necessary performance requirements. MDEP has addressed this concern through project-specific permit conditions which allow a "soft landing" approach. This soft landing allows the permit to be written such that time for testing and evaluation of the BACT/LAER control technology is allowed and there is an opportunity to revise permit conditions and substitute technology if it is demonstrated that the BACT/LAER standard cannot be achieved. A November 11, 1998, letter from Jan Kreminski of ABB Environmental Systems Division to Ed Braczyk of MDEP, states that ABB will offer SCONOx for sale subject to the soft landing as part of ABB's turnkey power plant projects. However, the letter also states that ABB is moving toward performing the necessary testing for scale-up with the expectation of meeting emission levels and being able to offer SCONOx without the soft landing.

More recently, a February 18, 1999, letter from Robert Danziger of Sunlaw Energy Corporation to Dr. Barry Wallerstein of SCAQMD proposes a NO_X emission rate of 1 ppmvd at 15 percent oxygen averaged over 1 hour for a 840 MW combined-cycle gas-fired power plant in Los Angeles County, California. The project will include three ABB GT KA 24-1 gas turbines. The NO_X emission level will be achieved using SCONOx. There are no ammonia emissions from the SCONOx technology. This project represents a refining of the SCONOx control technology which is already recognized as achieved in practice at 2.0 ppmvd at 15 percent oxygen. The Application for Certification (AFC) is tentatively scheduled to be filed with the California Energy Commission in September 1999.

c. Lower Emission Levels with Selective Catalytic Reduction

In line with the push toward zero ammonia emissions, power plant projects in Massachusetts have proposed very low NO_X and ammonia slip limits using selective catalytic reduction. Two power plant projects have received "conditional" approval of their air quality plans from the Massachusetts Department of Environmental Protection. The projects were conditionally approved because specific information on the emission control systems (specific manufacturer, model number, and operational parameters), construction plans, certain plant operational and maintenance procedures, and specific continuous emission monitors (CEMs) information had not been finalized at the time of issuance.

The first project is ANP Blackstone in Blackstone, Massachusetts. ANP Blackstone is a 580 MW combined-cycle power plant. The power plant will consist of two parallel power trains, each including one 180 MW (210 MW with steam augmentation) ABB GT-24 gas turbine. Emission limits are provided for four different loads. The proposed limits are 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour. The limit increases to 3.5 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour when steam injection for power augmentation is used. Overall annual NO_X emissions are limited to 2.3 ppmvd at 15 percent oxygen over a 12-month rolling average.

The second project is ANP Bellingham in Bellingham, Massachusetts. ANP Bellingham is a 580 MW combined-cycle power plant. The power plant will consist of two parallel power trains, each including one 180 MW (210 MW with steam augmentation) ABB GT-24 gas turbine. Emission limits are provided for four different loads. The proposed limits are 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour. The limit increases to 3.5 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour when steam injection for power augmentation is used. Overall annual NO_X emissions are limited to 2.3 ppmvd at 15 percent oxygen over a 12-month rolling average.

Another project, 360 MW Island End Cogeneration, in Massachusetts, is still in the draft stage and has not been submitted for pubic review. It is expected that the proposed emission levels will be 2.0 ppmvd NO_X at 15 percent oxygen and 2.0 ppmvd ammonia at 15 percent oxygen averaged over 1 hour using selective catalytic reduction.

2. Developing Control Technologies

a. XONON

XONON is a NO_X control mechanism (and also results in low-level CO and VOC emissions) accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_X is formed. The XONON combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

There is currently one field installation of the XONON technology at a municipal power company, Silicon Valley Power, in Santa Clara, California, being used as a “test bed” for engineering studies on the XONON system. Exhaust gas from the turbine is ducted to a vertical stack equipped with sampling ports and CEMs. Emission test data have indicated NO_X levels from 1.33 to 4.04 ppmvd at 15 percent oxygen over a range of turbine loads. This facility consists of a 1.5 MW simple-cycle Kawasaki M1A-13A gas turbine. There is not yet sufficient operating data to deem this level of control achieved in practice for the operation. Catalytica Combustion Systems (manufacturer of XONON) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON. General Electric has expressed its desire to work with Catalytica to adapt XONON to its Frame E-class and F-class turbines in order to demonstrate the technology on a larger scale and commence marketing.

b. Low-NO_X Duct Burner

Coen Company submitted a proposal in February 1999 to ARB's Innovative Clean Air Technology (ICAT) Program to develop and demonstrate a low-NO_X duct burner for cogeneration that would reduce NO_X emissions below 5 ppmvd at 15 percent oxygen, in order to match the NO_X emissions performance of XONON. The project will utilize advanced fuel and air mixing strategies, stability enhancements, and control system design to achieve the target NO_X levels. Use of the new low-NO_X duct burner technology in conjunction with XONON has the potential to match BACT emission levels without the need for add-on control systems such as selective catalytic reduction. Projected date of commercial availability is 2001 to 2002.

I. Discussion and Recommendations

1. Simple-Cycle Gas Turbines

The most stringent NO_X BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5 ppmvd NO_X at 15 percent oxygen averaged over 3 hours. The determination was made for a nominally rated 42 MW power plant consisting of a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. The gas turbine has been in operation since 1995. Since startup, the gas turbine has demonstrated compliance with the NO_X emission limit in three consecutive years of source testing. NO_X emissions varied from 3.957 to 4.72 ppmvd NO_X at 15 percent oxygen. Considering that the Carson Energy Group represents the most stringent NO_X BACT which has been achieved in practice, staff recommends a BACT level for NO_X emissions from simple-cycle gas turbines of 5 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbines

The most stringent NO_X BACT limit for an operating combined-cycle/cogeneration gas turbine is 3 ppmvd at 15 percent oxygen averaged over 3 hours. This emission level was achieved on a 102 MW combined-cycle Siemens V84.2 gas turbine at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, with dry low-NO_X burner and selective catalytic reduction. This unit has been operating since October 1997. Two consecutive annual source tests at the power plant recorded emission levels of 2.39 and 2.47 ppmvd NO_X at 15 percent oxygen.

The most stringent BACT limit for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit issued for the Sutter Power Plant near Yuba City, California. This determination was for a Westinghouse 501F gas turbine nominally rated at 170 MW. It requires 2.5 ppmvd NO_X at 15 percent oxygen averaged over 1-hour. This low emission level will be achieved using dry low-NO_X burners and selective catalytic reduction.

Emission levels of 2.0 ppmvd NO_X at 15 percent oxygen using 15 minute averages measured with CEMs were achieved at Federal Cogeneration in Los Angeles, California, utilizing water injection in conjunction with SCONOx. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. Initially, six months of CEMs data from June to December 1997 were examined by both the United States Environmental Protection Agency (U.S. EPA) and the South Coast Air Quality Management District (SCAQMD). Considering the circumstances, U.S. EPA subsequently deemed 2.0 ppmvd at 15 percent oxygen with a 3-hour averaging time as demonstrated in practice. This finding was presented in a March 23, 1998, letter from Matt Haber of U.S. EPA to Robert Danziger of Goal Line Environmental Technologies. U.S. EPA acknowledged that future combined-cycle gas turbine projects subject to LAER must recognize the 2.0 ppmvd limit. U.S. EPA also acknowledged that future combined-cycle gas turbine projects subject to BACT as required in Part C of the federal Clean Air Act should consider the 2.0 ppmvd limit when performing their top-down BACT analysis. The SCAQMD subsequently determined BACT as 2.5 ppmvd at 15 percent oxygen with 1-hour averaging[5]. U.S. EPA correspondence of June 10, 1998, subsequent to this determination recognized 2.0 ppmvd and 2.5 ppmvd at 15 percent oxygen with 3 and 1-hour averaging times, respectively, as levels that would represent BACT.

In light of the above findings, staff recommends a BACT level for NO_X emissions from combined-cycle and cogeneration gas turbines of 2.5 ppmvd at 15 percent oxygen averaged over 1 hour. In addition to the Sutter Power Plant, this NO_X BACT level is being proposed for other combined-cycle and cogeneration power plant projects currently in review through the California Energy Commission's siting process. These power plants include: High Desert Power Plant, La Paloma Generating Company, Sunrise Cogeneration, Delta Energy Center, and Metcalf Energy Center. Use of dry low-NO_X combustors in conjunction with selective catalytic reduction to meet the NO_X emission level was confirmed for High Desert Power Plant, La Paloma Generating Company, and Sunrise Cogeneration.

III. POTENTIAL METHODS OF CO EMISSION CONTROL

A. CO Formation Mechanism

Proper mixing of air and fuel is important for complete combustion to occur. When a hydrocarbon fuel, such as natural gas, burns completely, the oxygen in the air combines with the hydrogen to form water (H_2O) and with the carbon to form carbon dioxide (CO_2). If the combustion is incomplete, some of the carbon atoms combine with only one oxygen atom to form CO. Because oxygen is not ideally available in stoichiometric amounts, the carbon in the gas is not oxidized completely to CO_2 and CO is formed.

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[5] NO_X emission averaging time is not included in the BACT summary; however SCAQMD staff report clarifies the averaging time as 1 hour.

B. Combustion CO Controls

Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced CO emissions. Residence time is the amount of time for the combustion gases to flow through the combustor. The residence time can be increased by augmenting the length of the combustor. The longer the residence time, however, the more NO_X emissions are produced due to exposure of the combustion gases to high temperatures for increased periods of time.

3. Flue-Gas CO Controls

1. Oxidation Catalyst

In catalytic oxidation, a catalyst is used to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form CO_2 and H_2O. Typical control efficiencies from an oxidation catalyst are from 80 to 90 percent.

2. SCONOx

In addition to NO_X, the SCONOx catalyst system also removes CO emissions by oxidizing CO to CO_2. The reaction is shown below.

$$CO + ½ O2 \rightarrow CO2$$

A more lengthy description of the SCONOx technology is described in the previous discussion of flue-gas NO_X controls.

D. Exhaust Temperature Considerations

As was iterated in the discussion of NO_X emission controls, the efficiency of some CO control technologies is limited by temperature. This is especially true of catalytic controls. Catalytic control efficiencies may be reduced at hot or cold temperatures. For example, hot temperatures associated with uncooled exhaust may cause sintering of a catalyst. Conversely, low temperatures can result in higher CO emissions due to the fact that catalysts normally require a minimum temperature before they become chemically active.

5. Current SIP Control Measures

Historically, two forms of CO emission controls have been used on gas turbines. Combustion controls were used by the mid-1980s to achieve emission levels down to 10 ppmvd at 15 percent oxygen. In the late 1980's, oxidation catalysts were used on larger gas turbine cogeneration units. Oxidation catalysts can achieve 80 to 90 percent control of CO emissions. To date, use of oxidation catalysts have been largely limited to cogeneration and combined-cycle power plants. Although high temperature oxidation catalysts are available, sintering problems can appear at flue gas temperatures above 1050 °F. Simple-cycle gas turbines with lower flue gas temperatures have been controlled with high temperature oxidation catalysts.

Currently, only two areas are designated nonattainment for the California CO ambient air quality standards: Los Angeles County and the city of Calexico in Imperial County. The only area of California designated nonattainment for the national CO ambient air quality standards is the South Coast Air Basin.[6] In both cases, CO violations arise primarily from concentrated motor vehicle emissions. As a result, districts have not historically instituted control measures that have applied specifically to the regulation of CO emissions from gas turbines. The only California district with a CO emissions limit for gas turbines is the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). SJVUAPCD Rule 4703 limits CO emissions from gas turbines to 25 to 250 ppmvd at 15 percent oxygen averaged over 3 hours, depending on turbine design and use. The control measure is applicable to stationary gas turbines of at least 0.3 MW.

F. Control Techniques Required as BACT

Tables C-5 and C-6 list the most stringent CO emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

Table C-5: CO Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy	A/C: 11013 Issued: 7/23/93	Oxidation	5.93 lb/hr (3-hr average)	5.97

[6]California Air Resources Board "The 1999 California Almanac of Emissions & Air Quality," pp. 24-25.

Table C-5: CO Emission Controls Required for Simple-Cycle Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	P/O: 12830 Startup: 1995	catalyst	and 142.3 lb/day	
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbines	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Combustion control	80 lb/hr and 0.042 lb/MMBrtu	19
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Good combustion practices	0.0677 lb/MMBtu	28.6

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	A/C: 01-92-5231 to 01-92-5261 Issued: 6/9/93 P/O: 01-92-5231 to 01-92-5261 Startup: 8/1/93	Oxidation catalyst	1.8 ppmvd @ 15% O_2 (1-hr average)	1.8
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Oxidation catalyst	CTG: 8.11 lb/hr (3-hr average)	2.92
			CTG + DB: 9.63 lb/hr (3-hr average)	2.99
Sutter Power Plant	CEC Docket: 97-	Oxidation	4.0 ppmvd @	4.0

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and driving a common 160 MW steam turbine	AFC-2 Issued: 4/14/99 Startup: not built yet	catalyst	15% O_2 (24-hr average)	
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Engelhard Oxidation catalyst	5.9 ppmvd @ 15% O_2 (3-hr average)	5.9
La Paloma Generating Company Four 1,736 MMBtu/hr ABB GT-24 OTC gas turbines producing 172 MW each and four steam turbines producing 90 MW each	A/C: S-3412-1-0, S-3412-2-0, S-3412-3-0, S-3412-4-0 Issued: 5/26/99 Startup: not built yet	Oxidation catalyst	6 ppmvd @ 15% O_2 (3-hr average) at >73% load and 10 ppmvd @ 15% O_2 (3-hr average) at <73% load	6 (>73% load) 10 (<73% load)
Pittsburg District Energy Facility Two 1,929 MMBtu/hr General Electric Frame 7FA PG 7231 gas turbines with 83 MMBtu/hr auxiliary-fired HRSG producing 170 MW and 90 MW steam turbines	A/C: 18595 Issued: 6/10/99 (FDOC date) Startup: not built yet	Oxidation catalyst	6 ppmvd @ 15% O_2 (3-hr average)	6
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine and HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Oxidation catalyst	10 ppmvd @ 15% O_2 (3-hr average) and 252.6 lb/day	10
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW.	A/C: N-3233-1-0 Issued: 3/16/94 P/O: N-3233-1-0 Issued: 7/21/95	Oxidation catalyst	16.0 ppmvd @ 15% O_2 (3-hr average)	16

Table C-6: CO Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of CO Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Good combustion practices	CTG: 5.93 lb/hr (3-hr average) and 142.3 lb/day	5.94
			CTG + DB: 40.0 lb/hr (3-hr average) and 547.0 lb/day	32.95

G. Emission Levels Achieved in Practice

Tables C-7 and C-8 list the most stringent CO emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas.

Table C-7: CO Emission Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of CO Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Oxidation catalyst	0.18 lb/hr in Sep-Oct 1995	0.16
		0.196 lb/hr in Nov 1996	0.18
		0.07 lb/hr in Nov 1997-Jan 1998	0.06
Northern California Power Agency 325 MMBtu/hr General Electric Frame 5 gas turbine producing 25.24 MW	Good combustion practices	1.04 ppmvd @ 15% O_2 in May 1997	1.04

Table C-8: CO Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of CO Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbine with HRSG producing 121 MW each and two 40 MW steam turbines	W.R. Grace Oxidation catalyst	0.27 ppmvd and 1.1 ppmvd @ 15% O_2 in 1996	0.27 and 1.1
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	Engelhard Oxidation catalyst	1.11 ppmvd @ 15% O_2 in Jun 1997	1.11
		2.02 ppmvd @ 15% O_2 in Jun 1998	2.02
Modesto Irrigation District 460 MMBtu/hr General Electric LM5000 PD gas turbine with HRSG producing 49.9 MW	Oxidation catalyst	1.79 ppmvd @ 15% O_2 in 1996	1.79
		1.03 ppmvd @ 15% O_2 in 1997	1.03
		0.7 ppmvd @ 15% O_2 in 1998	0.7
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Oxidation catalyst	Both 0.1 ppmvd @ 15% O_2 in 1993	0.1
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	Oxidation catalyst	CTG + DB: 0.50 lb/hr in Oct 1997	0.16
		CTG + DB: 1.89 lb/hr in Oct 1998	0.62

H. More Stringent Control Techniques

1. Technologically Feasible Controls

Source testing at Newark Bay Cogeneration Partnership resulted in compliance with a permitted CO emission limit of 1.8 ppmvd at 15 percent oxygen through use of an oxidation catalyst. The facility is a 136 MW cogeneration plant with two 617 MMBtu/hr natural gas-fired combustion turbines located in Newark, New Jersey, in a federal CO nonattainment area. Source testing is not required on an annual basis, however, so assessment as to whether the level has been demonstrated cannot be determined without review of CEMs data.

Goal Line Environmental Technologies claims SCONOx can achieve 2.0 ppmvd CO at 15 percent oxygen averaged over 1 hour. The basis for this claim is CEMs operating data from Federal Cogeneration in Los Angeles, California, which uses water injection in conjunction with SCONOx. This facility consists of a 32 MW combined-cycle General Electric LM2500 gas turbine. Staff was unable to verify this claim by the time of publication of this guidance document.

2. Developing Control Technologies

Staff is not aware of any new CO abatement technologies currently under development which are actively targeting the gas turbine market.

I. Effect of CO Oxidation Catalyst on PM_{10} Emissions

There has been some concern expressed in comments received by staff that oxidation catalysts can oxidize sulfur dioxide (SO_2) to sulfate. The proponents of this theory generally believe that such sulfate production provides a reason to reconsider the relative merits of oxidation catalysts for the purpose of controlling CO and VOC. So far, the conversion rate assumed and accepted in a recently approved project is the 10 percent conversion of fuel sulfur to sulfate assumed on the Sutter Power Plant. Other parties providing comments assert that there is no evidence of significant conversion of SO_2 to sulfate across the oxidation catalyst.

One commenter points out that there will be a general emission increase of all air pollutant emissions attributable to a marginal increase in fuel consumption required to overcome the extra back pressure from the oxidation catalyst. In addition, the commenter claims that an 80 percent conversion of SO_2 to sulfate will occur across the oxidation catalyst. Assuming a fuel consumption of 2,003 million British thermal units per hour (MMBtu/hr) of natural gas with a heating value of 23,141 Btu/lb and a sulfur content of 0.25 grains per standard cubic foot (gr/scf), the commenter's analysis indicates PM_{10} emissions are increased by 2.18 lb/hr (combined-cycle gas turbine units of this size may emit from 11.5 to 17 lb/hr). However, there was no discussion in the commenter's letter providing a basis for the 80 percent conversion rate. A follow-up discussion with the commenter indicated the 80 percent conversion was derived from a graph of

SO_2 oxidation versus temperature for an Engelhard Camet oxidation catalyst which had been provided by a contractor for the San Diego Gas and Electric South Bay repower project.[7]

Assertions are countered by the Engelhard Corporation, an oxidation catalyst manufacturer. In a June 1, 1999, letter from Engelhard, a graph was submitted showing SO_2 conversion to sulfur trioxide (SO_3) across an Engelhard Camet Oxidation Catalyst as a function of temperature. The graph was for lower space velocities than normally used on California gas turbines, resulting in a liberal estimate of the conversion rate. Engelhard argues that at 600 to 650 °F, there is very little oxidation of SO_2 to SO_3 (a maximum of 10 percent), which is a typical gas temperature where the catalyst is installed. Inspecting other data provided, temperatures may potentially range up to 1000 °F, where the conversion rate could range above 85 percent. But even so, the letter maintains the following:

> "For this small level of SO_3 to contribute to particulate matter in the stack, it will have to react with ammonia and condense. Condensation will only occur if the dew point of ammonia reaction products is above the exhaust temperature at the stack. The dew point of sulfate reaction products is about 120 °F. This is well below the temperature in the stack of a combined cycle power plant and very close to ambient conditions in many locations. Therefore, the oxidation of SO_2 to SO_3 will not form particulate matter that can be detected in the gas turbine exhaust."

Engelhard goes on to contend that source tests on units with oxidation catalysts show low particulate matter concentrations that are comparable to those without oxidation catalysts. Furthermore, Engelhard indicates lower ammonia slip rates (e.g., 2 ppmvd) will reduce sulfate formation. Although ammonia slip rates are normally limited to 10 ppmvd at 15 percent oxygen,

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[7]In addition to discussion on SO_2 to sulfate conversion across an oxidation catalyst, a 6.5 percent conversion efficiency of fuel sulfur to sulfate during combustion was provided, a value that was provided in 1993 by Black and Veatch based on good engineering judgement for a Westinghouse gas turbine with dry low-NO_X combustors. The commenter noted that this conversion rate will likely be specific to the combustor design. He also noted that the same contractor provided a 10 percent estimate of SO_2 to sulfate conversion across an SCR catalyst. Using this data along with the 80 percent conversion across the oxidation catalyst, the overall conversion is 83 percent, assuming the oxidation catalyst is upstream of the SCR unit.

actual slip rates are normally much less, especially when the catalyst is new or after being regenerated.

The sulfate matter was also addressed in detail in a June 2, 1999, letter from the California Unions for Reliable Energy (CURE). The letter argued the following:

1. There is no correlation between flue gas temperature and particulate matter emissions. Because SO_2 to SO_3 conversion rates across a catalyst increase across the operating range of oxidation catalysts, one would expect greater sulfate and PM emissions at higher temperatures. Using a two-tailed Student's t test on two sets of test results from gas turbines with catalysts operated at low and high temperatures, there was no statistical difference between the two groups.
2. There is no correlation between fuel sulfur content and particulate matter emissions. This argument was supported by the lack of difference between gas turbines burning natural gas with low and high sulfur contents.
3. There is no difference in particulate matter emissions with and without CO oxidation catalysts. This argument was supported by looking at two gas turbines at Carson Energy, one with and the other without an oxidation catalyst. A two-tailed Student's t test showed no statistically significant difference between source tests from the two different units, although the populations of source tests were small.
4. PM emissions are too low to be caused by SO_2 oxidation sulfate. If one was to assume that all SO_3 attributed to an oxidation catalyst were converted to sulfate, measured PM should be an order of magnitude higher. ARB staff was unable to verify calculations used to make this argument.
5. Exhaust gas particulate matter concentrations are comparable to inlet concentrations. The letter provided data indicating that inlet particulate matter concentration are similar to filterable PM stack emissions. ARB staff does not necessarily agree, however, that the particles entering and exiting the gas turbine are the same.

Furthermore, the letter noted that Engelhard's assertions regarding sulfate formation were supported by the scientific literature.[8] Altogether, these argument are convincing, especially since they are supported by measurements and measurement-based calculations. Staff are not aware of any other similar measurement data that could support arguments to the contrary.
From the perspective of staff, there is not enough evidence indicating any significant increase PM_{10} emission caused by oxidation catalysts.

J. Discussion and Recommendations

[8]S. Matsuda et al. 1982. Deposition of ammonium bisulfate in the selective catalytic reduction of nitrogen oxides with ammonia. Ind. Eng. Chem. Prod. Res. Dev., 21:48-52.

1. Simple-Cycle Gas Turbines

The most stringent CO BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5.93 lb/hour, averaged over 3 hours (equivalent to approximately 5.97 ppmvd CO at 15 percent oxygen). The determination was made for a 42 MW nominal power plant consisting of a 450 MMBtu/hr General Electric LM6000 simple-cycle gas turbine equipped with an oxidation catalyst. The gas turbine has been in operation since 1995. Since startup, the gas turbine has demonstrated compliance with the CO emission limit in three consecutive years of source testing. CO emissions varied from 0.07 to 0.29 lb/hr (0.06 to 0.26 ppmvd CO at 15 percent oxygen). Considering that Carson Energy Group represents the most stringent CO BACT which has been achieved in practice, staff recommends a BACT level for CO emissions from simple-cycle gas turbines of 6 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbines

The most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Newark Bay Cogeneration Partners in Newark, New Jersey, at 1.8 ppmvd CO at 15 percent oxygen averaged over 1 hour. The determination was made for a 640 MMBtu/hr Westinghouse CW251/B-12 gas turbine using an oxidation catalyst. Compliance with the limits was demonstrated in a 1993 source test. The facility is required to source test every five years; staff at the New Jersey Department of Environmental Protection indicated additional source test results were not available at this time. ARB staff was not able to obtain CEMs data to verify whether the CO emission limit has been met on a continual basis to demonstrate whether the level has been achieved in practice.

The next most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sacramento Power Authority (Campbell Soup) in Sacramento County, California, at 9.63 lb/hr averaged over 3 hours (equivalent to approximately 2.68 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 1,257 MMBtu/hr Siemens V84.2 gas turbine using an oxidation catalyst. Two consecutive years of source testing indicate CO emissions vary from 0.50 to 1.89 lb/hr (0.16 to 0.62 ppmvd CO at 15 percent oxygen).

The next most stringent CO BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sutter Power Plant near Yuba City, California, at 4.0 ppmvd CO at 15 percent oxygen averaged over 24 hours. This determination applied to a 1,900 MMBtu/hr Westinghouse 501F gas turbine nominally rated at 170 MW. This CO emission level is proposed to be achieved using an oxidation catalyst. There is a similar CO BACT proposed for combined-cycle gas turbines at both the 1,048 MW La Paloma Generating Project[9]

[9]Note that La Paloma Generating Company is taking a tiered approach to limiting CO emissions based on load.

in Kern County, California, and the Pittsburg District Energy Facility in Pittsburg, California. The determinations are for 172 MW Asea Brown Bovari (ABB) KA-24 and 170 MW General Electric Frame 7FA gas turbines, respectively. They require 6.0 ppmvd CO at 15 percent oxygen using 3-hour averaging. The emission level will be achieved using an oxidation catalyst. Although the concentration associated with this determination is slightly less stringent than Sutter Power Plant, the averaging time is considerably shorter.

Based on the above, staff recommends a BACT level for combined-cycle and cogeneration gas turbines of 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours. Staff intends this CO BACT level to apply to CO nonattainment areas within California. Staff believes that this level of emissions is reasonable given that CO emission violations are primarily caused by concentrated motor vehicle emissions and the majority of California is designated attainment for State and federal CO emissions. The source test results at Sacramento Power Authority and other combined-cycle and cogeneration power plants indicate that 6.0 ppmvd CO at 15 percent oxygen averaged over 3 hours can be easily achieved with an oxidation catalyst. Also, because staff's analysis concludes that there is not sufficient evidence to establish oxidation catalyst contribution to sulfate formation, there is no reason to discount use of an oxidation catalyst for abatement of CO emissions.

IV. POTENTIAL METHODS OF VOC EMISSION CONTROL

1. VOC Formation Mechanism

Similar to CO emissions, VOC emissions result from incomplete combustion. VOC emissions are released in the exhaust flue gas when some of the hydrocarbon fuel remains unburned or is partially burned during combustion.

B. Combustion VOC Controls

Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced VOC emissions. Residence time is the amount of time for the combustion gases to flow through the combustor. The residence time can be increased by augmenting the length of the combustor. The longer the residence time, however, the more NO_X emissions are produced due to exposure of the combustion gases to high temperatures for increased periods of time.

C. Flue-Gas VOC Controls

1. Oxidation Catalyst

Like CO emissions, VOC emissions have traditionally been abated with combustion controls and oxidation catalysts. In addition, due to low VOC emission concentrations, the control of VOC emissions from gas turbines was relatively unimportant to regulators compared to those of NO_X and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions. Once oxidation catalysts were required for control of VOC, control efficiencies of 40 and 50 percent were apparently possible.

D. Current Stringent SIP Control Measures

Staff is not aware of any SIP control measures designed specifically to limit VOC emissions from gas turbines.

5. Control Techniques Required as BACT

Tables C-9 and C-10 list the most stringent VOC emission controls required as BACT that staff could locate for gas turbines of at least 20 MW fired on natural gas and used in simple-cycle, combined-cycle, and cogeneration power plant configurations.

Table C-9: VOC Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Carolina Power & Light Four 1,907.6 General Electric 7231 FA gas turbines	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Combustion control	2.8 lb/hr and 0.0015 lb/MMBtu	1.11
Sacramento Cogeneration Authority (Proctor & Gamble) 421.4 MMBtu/hr General Electric LM6000 gas turbine producing 25.24 MW	A/C: 11436 Issued: 8/19/94 Startup: not built yet	Oxidation catalyst	1.1 lb/hr (3-hr average)	1.98

Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Oxidation catalyst	2.46 lb/hr (3-hr average) and 59.1 lb/day	4.14

Table C-10: VOC Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine with HRSG producing 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Oxidation catalyst	0.6 ppmvd @ 15% O_2 (3-hr average) and 1.04 lb/hr and 25.0 lb/day	0.6
Sutter Power Plant Two 1,900 MMBtu/hr Westinghouse 501F gas turbines with two 170 MMBtu/hr auxiliary-fired HRSG producing 170 MW each and steam turbine producing 160 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Oxidation catalyst	1.0 ppmvd @ 15% O_2 (24-hr average)	1.0
La Paloma Generating Company Four 1,736 MMBtu/hr ABB GT-24 OTC gas turbines producing 172 MW each and four steam turbines producing 90 MW each	A/C: S-3412-1-0, S-3412-2-0, S-3412-3-0, S-3412-4-0 Issued: 5/26/99 Startup: not built yet	Oxidation catalyst (one unit may have SCONOx catalyst)	0.4 ppmvd @ 15% O_2 as propane (3-hr average)	1.1
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	A/C: 2-6101-00185 Issued: 6/6/95 P/O: 2-6101-00185 Issued: 11/12/97	W.R. Grace Oxidation catalyst	2.6 lb/hr (1-hr average) and 0.002 lb/MMBtu	1.31
Newark Bay Cogeneration Partnership	A/C: 01-92-5231 to 01-92-5261	Oxidation catalyst	4 ppmvd @ 15% O_2 (1-hr	4

Table C-10: VOC Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of VOC Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2, as CH_4
Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Issued: 6/9/93 P/O: 01-92-5231 to 01-92-5261 Startup: 8/1/93		average) and 0.005 lb/MMBtu and 3.20 lb/hr	
Crockett Cogeneration 1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW	A/C: S-201 Issued: 10/5/93 P/O: S-201 Issued: 12/19/96	Engelhard Oxidation catalyst	CTG: 2.8 lb/hr	1.10
			CTG + DB: 12.9 lb/hr	4.28
Sacramento Power Authority (Campbell Soup) 1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Oxidation catalyst	CTG: 3.21 lb/hr (3-hr average)	1.93
			CTG + DB: 9.01 lb/hr (3-hr average)	4.68
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with 99.8 MMBtu/hr auxiliary-fired HRSG producing 42 MW	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Good combustion practices	CTG: 2.46 lb/hr (3-hr average) and 59.1 lb/day	4.14
			CTG + DB: 3.75 lb/hr (3-hr average) and 90.2 lb/day	5.16

F. Emission Levels Achieved in Practice

Tables C-11 and C-12 list the most stringent VOC emission levels staff could locate which were achieved by simple-cycle, combined-cycle, and cogeneration power plant gas turbines while combusting natural gas. Note that no tests in either table exceed 2.0 ppmvd at 15 percent oxygen at 100 percent load.

Table C-11: VOC Emission Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas. Information provided applies to natural gas.	Oxidation catalyst	1.08 lb/hr (100% load) 1.21 lb/hr (50% load) in Sep-Oct 1995	1.98 (100% load) 3.77 (50% load)
		(no data @ 100% load) 0.476 lb/hr (50% load) in Nov 1996	1.46 (50% load)
		<0.51 lb/hr (100% load) <0.39 lb/hr (50% load) in Nov 1997-Jan 1998	0.95 (100% load) 1.21 (50% load)

Table C-12: VOC Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
Bear Mountain Limited G.T.E. cogeneration system including Stewart & Stevenson General Electric LM5000 gas turbine with HRSG producing 48 MW	Oxidation catalyst	<0.8 ppmvd @ 15% O_2 in Apr 1998	0.8
Brooklyn Navy Yard Cogeneration Two 1,503 MMBtu/hr Siemens V84.2 gas turbines with HRSG producing 121 MW each and two 40 MW steam turbines	W.R. Grace Oxidation catalyst	<0.67 ppmvd and <0.71 ppmvd @ 15% O_2 in 1996	0.67 and 0.71
Carson Energy 450 MMBtu/hr General Electric LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW.	Good combustion practices	CTG: 0.76 lb/hr (50% load) in Sep-Oct 1995	2.49 (50% load)

Table C-12: VOC Emission Source Test Results for Combined-Cycle and Cogeneration Gas Turbines			
Facility and Gas Turbine Description	Method of VOC Control	Measured Emissions	Approx. Emission Concentration in ppmvd at 15% O_2 as CH_4
		CTG: 0.520 lb/hr (50% load) in Nov 1996	1.85 (50% load)
Crockett Cogeneration	Engelhard Oxidation catalyst	<0.02 lb/hr in Jun 1997	0.00679
1,935 MMBtu/hr General Electric PG7221 (Frame 7FA) gas turbine with 349 MMBtu/hr auxiliary-fired HRSG producing 240 MW		0.116 lb/hr in Jun 1998	0.0406
Newark Bay Cogeneration Partnership Two 640 MMBtu/hr Westinghouse CW251/B-12 gas turbines	Oxidation catalyst	<1 ppmvd @ 15% O_2 in 1993	<1
Sacramento Power Authority (Campbell Soup)	Oxidation catalyst	CTG + DB: <1.42 lb/hr in Oct 1997	<0.8
1,257 MMBtu/hr Siemens V84.2 gas turbine with 200 MMBtu/hr auxiliary-fired HRSG producing 102 MW and 55 MW steam turbine		CTG + DB: 4.60 lb/hr in Oct 1998	1.79

G. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce VOC emissions from gas turbines.

H. Effect of Oxidation Catalysts on VOC Emissions and Measurement Issues

Staff has received comments arguing both for and against the use of oxidation catalysts to control VOC emissions. Arguments in favor of requiring an oxidation catalyst as part of the VOC BACT determination were expressed in a June 2, 1999, letter from CURE. The letter argued that collateral VOC emission reductions occur across the oxidation catalyst, depending on the catalyst operating temperature. An Engelhard oxidation catalyst performance curve (included as Figure 2) was provided as support. The curve indicates VOC removal efficiencies of 50 percent and greater. The letter also cites a 1995 source test at the Carson Energy Group in Sacramento County, California, as proof of its argument. The source test indicated VOC emissions of 0.96 lb/hr for the combined-cycle gas turbine without a CO oxidation catalyst, and

0.48 lb/hr for the peaking gas turbine with an oxidation catalyst. The letter also cites the benefit

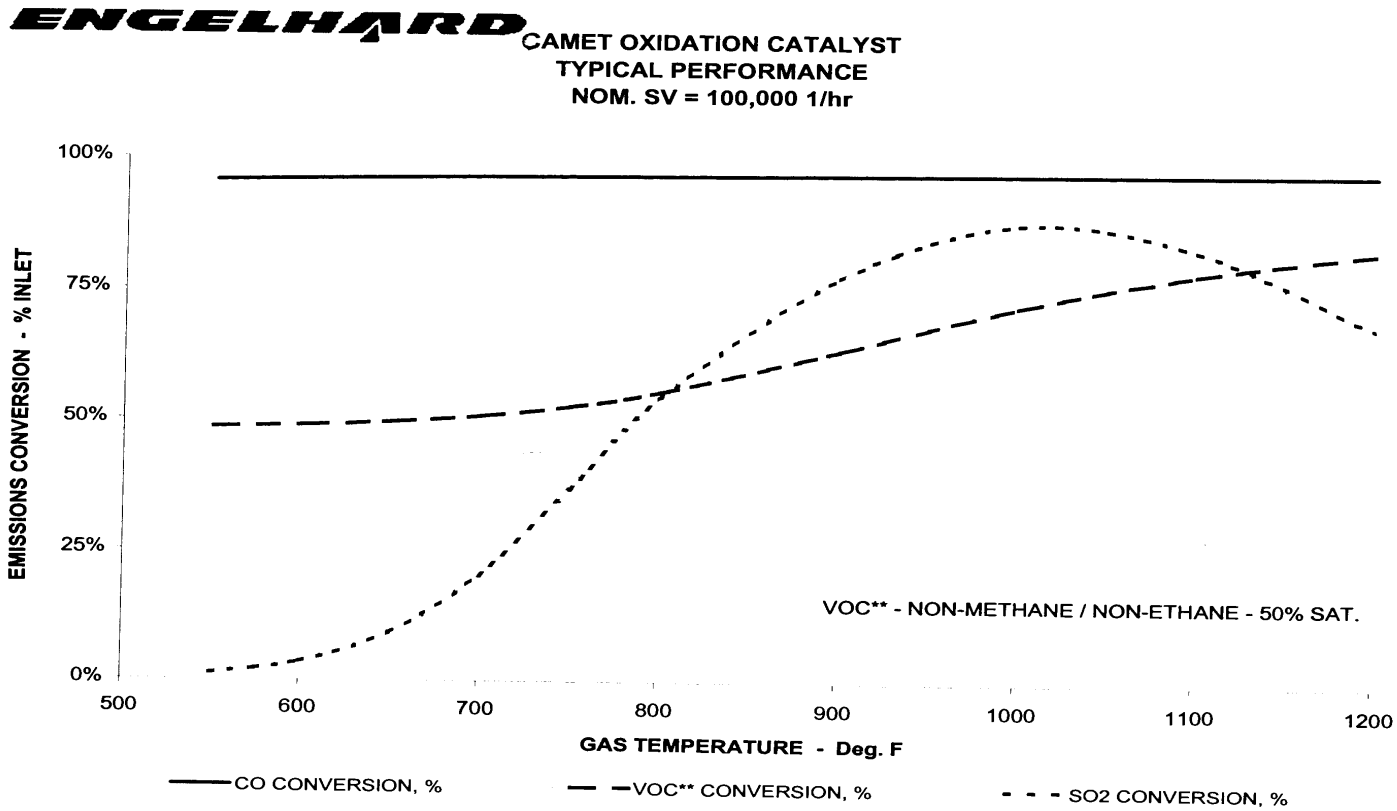

Figure 2 Catalytic Conversion Rates For An Engelhard Camet Oxidation Catalyst

of reduction of toxic emissions from natural gas combustion.

Opposing opinion regarding the benefits of an oxidation catalyst on VOC emissions was provided in a May 17, 1999, letter from Sierra Research. The letter argues that gas turbine vendors provide guarantees for total hydrocarbon emission rates which are on the order of 7 to 10 ppm; however lower levels are proposed by power plant project proponents because most of the hydrocarbons are methane. Project proponents have proposed various VOC levels based on different assumptions made. Some propose VOC emissions of 0.7 to 1.0 ppm based on the assumption that the fraction of methane in the exhaust is equal to the fraction of methane in the natural gas fuel. Others propose 1.4 to 2.0 ppm based on vendor recommendations that 80 percent of total hydrocarbon emissions are methane. Still others propose 3.5 ppm assuming 50 percent of total hydrocarbons in the exhaust are methane. Sierra Research provided a listing of VOC source test results from several gas turbines, most equipped with oxidation catalysts; results ranged from 0.7 to 3.9 ppm. Sierra Research also compares source test results at Carson Energy Group for both catalyst-equipped and non-catalyst controlled gas turbines. The comparison was for testing at 50 percent load which resulted in higher VOC emissions from the catalyst-controlled gas turbine. Sierra Research also challenges the accuracy of VOC test methods at low levels and gives minimum detection limits for various VOC test methods: EPA Method 25 (minimum 50 ppm), EPA Method 25A (varies depending on calibration gas), and SCAQMD Method 25.1 (minimum 25 ppm). Sierra Research acknowledges that there are other test methods that are not included in agency guidelines, but states that they are unaware of any VOC test method with a detection level below 10 ppm. Based on the lack of demonstrated effectiveness from the oxidation catalyst and measurement issues, Sierra Research recommends a VOC BACT level of no less than 3.5 ppmvd at 15 percent oxygen.

Staff does not feel that the source tests conducted at Carson Energy Group provide a good basis for comparing the effect of an oxidation catalyst on VOC emissions from natural gas-firing on two similar gas turbines. Source test data which could be compared are only available when firing at 50 percent load. The combustion inefficiencies associated with lower loads are expected to result in higher emission levels. One hundred percent load conditions were only available for the combined-cycle gas turbine (non-catalyst equipped) while firing on a mixture of natural gas and digester gas. Staff does not feel this data can be adequately compared due to the different fuels.

Staff acknowledge that there has been a lack of use of the most reliable source test methods in assessing VOC emissions from power plant gas turbines in some cases. Staff agrees that EPA Method 25 was not designed to measure levels below 50 ppm. Therefore, EPA Method 25 is inappropriate for the level of VOC emissions expected from gas turbines. Staff of the SCAQMD confirmed that SCAQMD Method 25.1 is no longer used by the district. Instead a revised version, SCAQMD Method 25.3, is applied. The method protocol is currently in review with U.S. EPA. SCAQMD Method 25.3 has sensitivities that can measure effectively down to as low as 1 ppm.

District representatives and private source testers have confirmed that there are reliable source test methods available to measure VOC emissions below 10 ppm. For example, EPA Method 25A can measure down to the 1 ppm level, and perhaps, even as low as 0.5 ppmvd for alkanes, alkenes, and arenes, with a highly sensitive flame ionization detector (FID).[10] One drawback is that Method 25A will tend to underestimate VOC levels where polar organics are present. Another option for acceptable VOC emission measurement is EPA Method 18.

VOC emissions data from available combined-cycle/cogeneration gas turbine source tests, using acceptable methods, consistently indicate emissions no greater than 2.0 ppmvd VOC at 15 percent oxygen have been achieved with the application of an oxidation catalyst.

I. Discussion and Recommendations

1. Simple-Cycle Gas Turbine

The most stringent VOC BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carolina Power & Light in Goldsboro, North Carolina, at 0.0015 lb/MMBtu (equivalent to approximately 1.11 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 1,907.6 MMBtu/hr General Electric 7231 FA gas turbine using combustion control while firing on natural-gas fuel. A recent conversation with the permitting engineer at the North Carolina Department of Environment and Natural Resources in May 1999 confirmed that the facility had not commenced operation yet.

The next most stringent VOC BACT found for a simple-cycle gas turbine was required in the preconstruction permit for Sacramento Cogeneration Authority (Proctor & Gamble) in Sacramento County, California, at 1.1 lb/hr (equivalent to approximately 1.98 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 421.4 MMBtu/hr General Electric LM6000 gas turbine using an oxidation catalyst. Air district staff confirmed in April 1999 that the simple-cycle gas turbine had not been installed yet.

The next most stringent VOC BACT found for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 2.46 lb/hr (equivalent to approximately 4.14 ppmvd VOC as methane at 15 percent oxygen). The determination was made for a 450 MMBtu/hr General Electric LM6000 PA gas turbine using an oxidation catalyst. This gas turbine has been in operation since 1995. Three consecutive years of source testing at Carson Energy Group indicate VOC emissions vary from 0.51 to 1.08 lb/hr averaged over 3 hours (0.95 to 1.98 ppmvd VOC as methane at 15 percent oxygen).

[10]Personal communications with Dr. Eric D. Winegar of Applied Measurement Science.

Based on the above, the most stringent BACT requirements are in the 1 to 2 ppmvd VOC at 15 percent oxygen range. Source tests at Carson Energy Group demonstrate VOC emission levels of no more than 2 ppmvd at 15 percent oxygen can be met on a consistent basis. Therefore, staff recommends a BACT emission level for VOC from simple-cycle gas turbines of 2 ppmvd at 15 percent oxygen averaged over 3 hours.

2. Combined-Cycle and Cogeneration Gas Turbine

The most stringent VOC BACT for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Bear Mountain Limited in Kern County, California, at 0.6 ppmvd VOC at 15 percent oxygen. The determination was made for a 48 MW General Electric LM5000 gas turbine using a CO oxidation catalyst. The last source test resulted in emissions of less than 0.8 ppmvd VOC at 15 percent oxygen.

The next most stringent VOC BACT for a combined-cycle/cogeneration gas turbine is proposed for the High Desert Power Plant in San Bernardino County, California, at 1.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour. The power plant will consist of either two or three gas turbines, with total power plant output nominally rated at 700 or 750 MW. This VOC emission level is proposed to be achieved using a CO oxidation catalyst with approximately 40 percent VOC destruction efficiency.

The next most stringent VOC BACT found for a combined-cycle/cogeneration gas turbine was required in the preconstruction permit for Sutter Power Plant near Yuba City, California, at 1.0 ppmvd VOC at 15 percent oxygen averaged over 24 hours. The determination was made for a 1,900 MMBtu/hr Westinghouse 501F gas turbine nominally rated at 170 MW. This VOC emission level is proposed to be achieved using a CO oxidation catalyst. The Sutter Power Plant was approved by the California Energy Commission (CEC) on April 14, 1999.

There is a similarly stringent VOC BACT proposed for combined-cycle gas turbines at the 1,048 MW La Paloma Generating Project in Kern County, California. This determination is for an Asea Brown Bovari (ABB) KA-24 gas turbine nominally rated at 172 MW. It requires 0.4 ppmvd as propane[11] at 15 percent oxygen using 3-hour averaging. This emission level will be achieved using an oxidation catalyst. Although the concentration associated with this determination is slightly less stringent than that for Sutter Power Plant, the averaging time is considerably shorter.

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[11]VOC concentration given as 0.4 ppmvd as propane is approximately equal to 1.1 ppmvd as methane.

Two years of source testing at Crockett Cogeneration in Crockett, California, indicate VOC emissions vary from about 0.007 to 0.085 ppmvd precursor organic compound (POC) as methane at 15 percent oxygen over a 1-hour average. The 249 MW plant consists of a combined-cycle General Electric Frame 7FA combustion gas turbine with an oxidation catalyst. The 0.007 ppmvd VOC level corresponds to the sensitivity threshold of the source test method. Bay Area staff indicated a more appropriate characterization of the measured value is as less than 1 ppmvd at 15 percent oxygen.[12]

Staff calculations estimate uncontrolled VOC emissions from gas turbines of approximately 4 ppmvd at 15 percent oxygen.[13] Using a conservative estimate of VOC emission control from the oxidation catalyst of 50 percent, the emission level is 2.0 ppmvd VOC at 15 percent oxygen. Available source tests at Crockett Cogeneration and other similar power plants consistently indicate emissions of no greater than 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour with use of an oxidation catalyst. Based on the above, staff recommends a BACT level of 2.0 ppmvd VOC at 15 percent oxygen averaged over 1 hour (or equivalent limit of 0.0027 lb VOC/MMBtu, higher heating value) for combined-cycle and cogeneration gas turbines.

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[12]Personal communications with Ken Lim of the Bay Area Air Quality Management District.

[13]Based on U.S. EPA AP-42 Chapter 3.1, “Stationary Gas Turbines for Electricity Generation,” January 1995 edition.

V. POTENTIAL METHODS OF PM_{10} EMISSION CONTROL

A. General Concerns in Controlling PM_{10} Emissions from Gas Turbines

There are a limited number of options for controlling PM_{10} emissions from gas turbines. These emissions are below one micrometer in aerodynamic diameter[14] and diluted by the high volume of exhaust from a turbine. Potential add-on controls such as filtering devices, venturi scrubbers, and electrostatic precipitators would be rendered less effective under these conditions and have to be scaled-up in size. Neither has there been much success in reducing PM_{10} emissions through combustion controls. The only meaningful control of turbine exhaust emissions has been through limiting fuel type and sulfur content.

Gaseous fuels are generally associated with the least PM_{10} emissions due to their lower sulfur, nitrogen, and ash contents. In addition, gaseous fuels can be more easily mixed with the combustion air than liquid fuels, which must be atomized into the combustion mixture and then combusted near the droplet surfaces. Less soot production is expected with gaseous fuels since fuel rich zones of combustion near the droplets are avoided.

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[14]U.S. EPA AP-42, Table 3.1-1 indicates all PM_{10} emissions from gas turbines fired on natural gas are below one micrometer in size. Furthermore 40 percent of the emissions are below 0.10 micrometers in size.

PM_{10} emission rates from gas turbines are relatively low when firing on natural gas. However the importance of PM_{10} emission control for gas-fired gas turbines is changing. Many of the new generation turbines proposed for California power plants are much larger than their predecessors. Even though these new larger turbines generally have lower emission concentrations of PM_{10} [15], their higher emission rates can exceed 70 tons per year**.** This level of emissions exceeds the major source threshold for PM_{10} in serious nonattainment areas.

B. Current SIP Control Measures

Staff is unaware of any SIP control measures designed specifically to limit PM_{10} emissions from gas turbines.

C. Control Techniques Required as BACT

Although other gaseous fuels are available, natural gas is by far the most prominently used gaseous fuel. In California, BACT decisions often require the use of natural gas, with composition meeting the specifications of the Public Utilities Commission (PUC). Although the PUC allows total sulfur contents up to 5 grains of sulfur per 100 standard cubic feet (5 gr S/100 scf), gas utilities around the State specify levels of 1 gr S/100 scf or less in purchase contracts with natural gas suppliers.

Tables C-13 and C-14 list several PM_{10} emission controls required as BACT for simple-cycle, combined-cycle, and cogeneration power plant configurations. These determinations were mostly found in the CAPCOA BACT Clearinghouse and the EPA RACT/BACT/LAER Clearinghouse. The most stringent BACT limit for simple-cycle gas turbines is 0.00081 grains per dry standard cubic foot (gr/dscf) at 3 percent CO_2 for a Westinghouse gas turbine at Carolina Power and Light. Correspondingly, the most stringent BACT limit for combined-cycle and cogeneration units is 0.00043 and 0.00017 gr/dscf at 3 percent CO_2 (firing a gas turbine with and without, respectively, duct burners) at Sacramento Power Authority (Campbell Soup). The latter BACT limits for Sacramento Power Authority are substantially less than any other limits governing a gas turbine with an auxiliary-fired HRSG. However, Sacramento Power Authority was able to comply with the former limit in both 1997 and 1998.

Table C-13: PM_{10} Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of	Emission	Approx.

[15]Proposed PM_{10} emission rates are approximately 12 percent of U.S. EPA AP-42 values for uncontrolled emissions from gas turbines fired on natural gas.

		PM_{10} Control	Limits	Emission Concentration in gr/dscf at 3% CO_2
Carolina Power and Light 1520 MMBtu/hr Westinghouse gas turbine limited to 2750 hr/yr of operation	A/C: 0820-0033 Issued: 8/31/94 P/O: 0820-0033 Startup: 6/1/96	Natural gas firing	5.9 lb/hr	0.00081
Carolina Power and Light (H.F. Lee Stream Electric Plant) 1907.6 MMBtu/hr General Electric PG 7231FA gas turbine fired on natural gas and #2 fuel oil	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Natural gas firing	9 lb/hr	0.0010
Carson Energy GE LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas.	A/C: 11013 Issued: 7/23/93 P/O: 12830 Startup: 1995	Natural gas firing	2.5 lb/hr	0.0010
Northern California Power Agency GE Frame 5 gas turbine producing 25.24 MW	A/C: N-583-1-2 Issued: 10/2/97 P/O: N-583-1-2 Issued: 3/23/98	Natural gas firing	0.013 lb/MMBtu	0.0027

Table C-14: PM_{10}. Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of PM_{10} Control	Emission Limits	Approx. Emission Concentration in gr/dscf at 3% CO_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 102 MW	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Natural gas firing	CTG: 1.0 lb/hr	0.00017
			CTG+DB: 3.0 lb/hr	0.00043
Crockett Cogeneration GE Frame 7FA with auxiliary-fired HRSG producing 240 MW in combined-	A/C: S-201 Issued: 10/5/93 P/O: S-201	Natural gas firing	10.8 lb/hr as filterables	0.0012 as filterables

Table C-14: PM_{10}. Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of PM_{10} Control	Emission Limits	Approx. Emission Concentration in gr/dscf at 3% CO_2
cycle mode	Issued: 12/19/96			
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Natural gas firing	CTG: 2.5 lb/hr (3-hr average)	0.0012
			CTG+DB: 3.5 lb/hr (3-hr average)	0.0013
Sutter Power Plant Two Westinghouse 501F gas turbines with auxiliary-fired HRSG producing 500 MW	CEC Docket: 97-AFC-2 Issued: 4/14/99 Startup: not built yet	Firing with PUC pipeline-quality natural gas firing	11.5 lb/hr (24-hr average)	0.0013

D. Emission Levels Achieved in Practice

With regard to simple-cycle units, two consecutive annual source tests at Carson Energy in Sacramento County, California, indicate PM_{10} emissions range from 0.00029 to 0.00041 gr/dscf at 3 percent CO_2. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine. These results indicate that levels of approximately 0.0004 gr/dscf at 3 percent CO_2 has been achieved for simple-cycle gas turbines.

With regard to combined-cycle and cogeneration units, two consecutive annual source tests at Sacramento Power Authority (Campbell Soup) in Sacramento County, California, indicate PM_{10} emissions range from 0.00027 to 0.00042 gr/dscf at 3 percent CO_2. The results were obtained on a 102 MW combined-cycle Siemens V84.2 gas turbine. These results indicate a level of approximately 0.0004 gr/dscf at 3 percent CO_2 has been achieved for combined-cycle and cogeneration units.

Table C-15: PM_{10} Source Test Results for Simple-Cycle Gas Turbines			
Facility and Gas Turbine Description	Method of	Measured Emissions	Approx. Emission

	PM_{10} Control		Concentration in gr/dscf at 3% CO_2
Carson Energy GE LM6000 gas turbine producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas.	Natural gas firing	0.63 lb/hr in Oct 1995	0.00029
		0.882 lb/hr in Nov 1996	0.00041

Table C-16: PM_{10} Source Test Results for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of PM_{10} Control	Measured Emissions	Approx. Emission Concentration in gr/dscf at 3% CO_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 103 MW	Natural gas firing	CTG+DB: 1.93 lb/hr in Oct 1997	0.00027
		CTG+DB: 2.98 lb/hr in Oct 1998	0.00042
Federal Cold Storage Cogeneration General Electric LM2500 gas turbine plus HRSG rated at 32 MW	Natural gas firing	0.0013 gr/dscf at 12% CO_2 on 6/12/97	0.00033
Crockett Cogeneration General Electric Frame 7FA producing with auxiliary fired HRSG rated at 260 MW	Natural gas firing	A maximum of 3.3 lb/hr was measured in two sets of three tests in 1997 and 1998	0.00035 as filterables
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	Natural gas firing	1.01 lb/hr in Oct 1995	0.00038
		2.08 lb/hr in Nov 1996	0.00079

E. More Stringent Control Techniques

Staff is not aware of any additional technologically feasible control techniques, existing or under development, to reduce PM_{10} emissions from gas turbines.

F. PM_{10} Measurement Concerns

1. Measurement of Filterable PM_{10} Emissions

According to conversations with power plant applicants and representatives, filterable PM_{10} emission concentrations for power plants are so low that source tests must occasionally be extended to collect enough sample. In addition, this level of emission is approaching limits of detection.

2. Measurement of Condensible PM_{10} Emissions

There are concerns that artifact PM_{10} in the form of sulfate is formed from absorbed SO_X in impingers used for measuring condensible PM_{10}. Staff is unaware of evidence for the occurrence and amount of SO_X absorption, but does not deny the probability of its existence. Although theoretical arguments for artifact sulfate formation in impingers is compelling, the amount of absorption has not been verified with any actual measurements, leaving any estimates very speculative.

G. Discussion and Recommendations

PM_{10} emissions are partially dependent on fuel composition. In addition to ash, other constituents of concern include fuel-bound sulfur and nitrogen. Natural gas has negligible amounts of all three constituents when compared to liquid or solid fuels. As a result, there should be minimal nitrate and sulfate production. Furthermore, the production of any thermally-induced nitrates and the organic fraction of PM_{10} can best be abated through the use of combustion controls. Therefore, for new gas turbines with state-of-the-art combustion design, PM_{10} emissions are most effectively reduced using natural gas fuel with low sulfur content.

Staff is unaware of any add-on control technologies that are feasible for reducing PM_{10} emissions in gas turbine flue gas. As a result, the lowest PM_{10} emissions are achieved through combustion of natural gas along with combustion design that minimizes NO_X and unburned hydrocarbons. Applicants have the ability to select a low-sulfur fuel, such as natural gas; however, only the gas supplier has the ability to limit fuel sulfur content.[16] Natural gas utility companies have the ability to specify fuel sulfur content in purchase contracts with gas suppliers. Two major California natural gas utility companies, i.e., Pacific Gas & Electric and Southern California Gas, use purchase contracts that specify levels no higher than 1 gr S/100 scf. Staff believe this represents a limiting circumstance in the maximum emission level of the sulfate portion of PM_{10}.

Considering the above, the default PM_{10} BACT requirement for simple-cycle, combined-

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[16]Under California Public Utilities Commission General Order 58-8, the total sulfur of gas supplied by any gas utility for domestic, commercial, or industrial purposes is limited to 5 grains of total sulfur per 100 standard cubic feet.

cycle, and cogeneration gas turbines is natural gas containing no more than 1 gr S/100 scf of total sulfur. In addition, staff believes that appropriate combustion controls and low sulfur fuel are essential components of a PM_{10} BACT determination for a gas turbine. Any emission limit required for BACT should correspond with a fuel gas sulfur content of 1 gr S/100 scf. Furthermore, there are "housekeeping measures" that can prevent emissions from the lube oil vent, including a lube oil vent coalescer and an associated opacity limit of 5 percent. These latter provisions were required at Badger Creek Limited on a 457.8 MMBtu/hr General Electric LM-5000 gas turbine cogeneration unit with a 48.5 MW capacity.

An example of a recent PM_{10} BACT limit on a large combined-cycle gas turbine was applied to the Sutter Power Plant. A PM_{10} limit of 11.5 lb/hr averaged over 24 hours assuming a fuel sulfur content of 0.7 gr S/100 scf and a 10 percent conversion of fuel sulfur to sulfate emissions. Staff calculations indicate that this limit is equal to an emission concentration of 0.00122 gr/dscf of exhaust gas at 3 percent CO_2. This determination applied to a Westinghouse 501F gas turbine nominally rated at 170 MW. In this case, the applicant presumed fuel sulfur content is below the 1 gr S/100 scf specified in the local gas utility company purchase contracts. Therefore, the applicant assumed the risk associated with fuel sulfur content excursions over 0.7 gr S/100 scf.

VI. Control of SO_X Emissions

A. General Concerns Regarding the Control of SO_X from Gas Turbines

Fuel sulfur is the source of SO_X emissions from gas turbines fired on natural gas. Since the sulfur content is so low, the natural gas odorant substantially contributes to the fuel sulfur content. SO_X emission concentrations are normally below 1 ppmvd for gas turbines fired on California natural gas. Controlling such low SO_X emissions is not feasible.

Since SO_X emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Although an applicant can select a low-sulfur fuel, such as natural gas, the applicant does not have control of fuel sulfur contents lower than that specified in contracts between gas utilities and gas suppliers. Entities regulated by the PUC in California have purchase contracts with an effective maximum of total sulfur content for natural gas of 1 gr S/100 scf (equivalent to approximately 17 ppmv S). The most stringent BACT required for a combined-cycle gas turbine is firing of low-sulfur natural gas. The natural gas should contain no more than 1 gr S/100 scf.

2. Current SIP Control Measures

Several California districts have SIP control measures limiting sulfur compounds (as sulfur dioxide) from fossil fuel-burning equipment used generally for the production of useful heat or

power.[17] The most stringent of these limits restrict sulfur dioxide emissions to no more than 200 lb/hr. This level of emissions is not approached with gaseous fuel combustion.

C. Control Techniques Required as BACT

SO_X BACT determinations for gas turbines are presented in Tables C-17 and C-18. The most stringent limit for simple-cycle gas turbines was 0.10 ppmvd at 15 percent oxygen on a General Electric Frame 7FA at H.F. Lee Steam Electric Plant. The most stringent limit for combined-cycle and cogeneration units was 0.12 ppmvd at 15 percent O_2 averaged over 3 hours. This limit was required at Sacramento Power Authority (Campbell Soup) for a 1,257 MMBtu/hr Siemens V84.2 gas turbine with a supplemental firing capacity of 200 MMBtu/hr and a total output of 157 MW.

Table C-17: SO_X (as SO_2) Emission Controls Required for Simple-Cycle Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Carolina Power and Light (H.F. Lee Stream Electric Plant) General Electric PG 7231FA simple-cycle gas turbine fired on natural gas and #2 fuel oil and rated at approximately 170 MW	A/C: 1812R18 Issued: 7/31/98 Startup: not built yet	Natural gas firing	1 lb/hr	0.10

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2

[17]Such rules may only apply to cogeneration and combined-cycle units. Others may apply more generally and may cover simple-cycle gas turbines.

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
Sacramento Power Authority (Campbell Soup) Siemens V84.2 gas turbine with auxiliary-fired HRSG producing 103 MW	A/C: 11456 Issued: 8/19/94 P/O: 13629 Startup: 1997	Natural gas firing	CTG: 0.75 lb/hr (3-hr average)	0.12
			CTG+DB: 0.87 lb/hr (3-hr average)	0.12
Bear Mountain Ltd. GE LM5000 with HRSG rated at 48 MW	A/C: S-2049-1-2 Issued: 8/19/94 P/O: S-2049-1-2 Issued: 10/4/95	Natural gas firing	7.2 lb/day (Not a BACT requirement)	0.13
PDC-El Paso Milford LLC Two ABB GT-24 gas turbines with HRSGs with a total rated output of 544 MW	A/C: 105-0068, 105-0069 Issued: 4/16/99 Startup: not built yet	Natural gas firing	0.0022 lb/MMBtu	0.42
Newark Bay Cogeneration Partnership, L.P. Westinghouse CW251/B-12 gas turbines rated at 68 MW	A/C: 01-92-5231 to 01-92-5261 Issued: 6/9/93 P/C: 01-92-5231 to 01-92-5261 Startup: 8/1/93	Natural gas firing	0.0026 lb/MMBtu	0.51
Carson Energy GE LM6000 gas turbine with auxiliary-fired HRSG producing 42 MW. Unit can co-fire with digester gas, but information here given for firing on natural gas	A/C: 11012 Issued: 7/23/93 P/O: 12829 Startup: 1995	Natural gas firing	CTG: 1.42 lb/hr (3-hr average) (Not a BACT Requirement)	0.63
			CTG+DB: 2.78 lb/hr (3-hr average)	1.0
Sutter Power Plant Two Westinghouse 501F gas turbines	CEC Docket: 97-AFC-2 Issued: 4/14/99	Firing with PUC pipeline-quality natural	1 ppmvd at 15% O_2 (24-hr average)	1

Table C-18: SO_X (as SO_2) Emission Controls Required for Combined-Cycle and Cogeneration Gas Turbines				
Facility and Gas Turbine Description	Permitting	Method of SO_X Control	Emission Limits	Approx. Emission Concentration in ppmvd at 15% O_2
with auxiliary-fired HRSG producing 500 MW	Startup: not built yet	gas firing		

D. Emission Levels Achieved in Practice

SO_X source tests for large gas turbines fired on natural gas are very rare. There were not enough such tests to evaluate what levels have been achieved in practice. Although several source test summaries were available, sufficiently complete data could not be obtained, with the exception of the SO_X source test at Harbor Cogeneration for a General Electric Frame 7 gas turbine rated at 82.345 MW. The measured emission concentration was 0.06 ppmvd at 15 percent oxygen.

E. More Stringent Control Techniques

1. Technologically Feasible Controls

SCOSOx is a catalytic sulfur removal system that works in conjunction with the SCONOx system to remove sulfur compounds from combustion exhaust streams. It is nearly identical to the SCONOx catalyst for NO_X removal except that it favors sulfur compound absorption and is installed upstream of the SCONOx catalyst. SCOSOx was installed in early 1999 at the Genetics Institute in Andover, Massachusetts, in conjunction with SCONOx. The 5 MW cogeneration plant consists of a 65 MMBtu/hr Solar Taurus Model 60 gas turbine with auxiliary-fired HRSG. The SCOSOx system was installed as a “guard bed” for the SCONOx system to enhance the control effectiveness of the NO_X catalyst. In this case, sulfur removal was not measured. Therefore, there is no opportunity to assess any SO_X emissions reductions associated with SCOSOx at this time. Goal Line Environmental Technologies is now supplying the SCOSOx catalyst automatically with the SCONOx technology.

2. Developing SO_X Control Technologies

Staff is not aware of any control technologies currently in development that would be applied to power plant gas turbines to specifically abate SO_X emissions.

F. Discussion and Recommendations

SO_X emissions result from the oxidation of fuel sulfur during combustion. Staff is unaware of combustion or demonstrated add-on controls feasible for controlling SO_X emissions from gas turbines. Therefore, staff recommends a SO_X BACT limit equivalent to gaseous fuel with a sulfur content of 1 gr S/100 scf. Based on mass balance calculations and assuming no fuel sulfur conversion to sulfate, a gas turbine firing on natural gas with this level of sulfur content will emit a maximum 0.55 ppmvd SO_X (as SO_2) at 15 percent oxygen. The district determination may also wish to require as BACT, compliance with a fuel sulfur content limit, especially if the content limit is below purchase specification used by the gas utility. In addition, staff suggests that an emission concentration limit corresponding to the assumed fuel sulfur content, i.e., 0.55 ppmvd at 15 percent oxygen or lower, may be appropriate.

APPENDIX C LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Acronym Meaning
A/C	Authority to Construct (e.g., permit to construct, preconstruction permit)
ARB	(California) Air Resources Board
BACT	best available control technology
BARCT	best available retrofit control technology
Btu	British thermal unit
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission
CEMs	continuous emissions monitors
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CTG	combustion turbine generator
DB	duct burner
dscf	dry standard cubic foot (feet)
FDOC	Final Determination of Compliance
gr	grains
H_2O	water
hr	hour
HRSG	heat recovery steam generator
LAER	lowest achievable emission rate
lb	pound(s)
MM	prefix used for million
MMBtu	million British thermal units
MW	megawatts
NO_X	oxides of nitrogen
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns or less
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
P/O	Permit to Operate
POC	precursor organic compounds
ppm	parts per million
ppmvd	parts per million dry volume
PUC	Public Utilities Commission
RACT	reasonably available control technology
ROG	reactive organic gases
scf	standard cubic foot (feet)
SCR	selective catalytic reduction
SIP	state implementation plan
SO_2	sulfur dioxide

APPENDIX C LIST OF ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Acronym Meaning
SO_X	oxides of sulfur
VOC	volatile organic compounds
U.S. EPA	United States Environmental Protection Agency

APPENDIX C REFERENCE LIST

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Appendix D:

MANUFACTURER EMISSION GUARANTEES FOR NO_X AND AMMONIA SLIP

MITSUBISHI HEAVY INDUSTRIES AMERICA, INC.
Power Systems Division / Los Angeles Office
660 Newport Center Drive, Suite 1000
Newport Beach, CA 92660

FACSIMILE MESSAGE

DATE: August 5, 1998

TO: Ms. Fox
Phone : 510-843-1126
Fax : 510-845-0983

COPY TO:

FROM: Ricardo Yoshida
Senior Project Engineer
Phone : 949-640-5941
Fax : 949-640-6945 / 6947
e-mail : ryoshida@mhia.com

MHIA REF. #: LA- **MHIA Project #:** N/A

SUBJECT: SCR Guarantees

REFERENCE: Combined Cycle / Conference call

Number of pages including cover sheet:

As per our phone conversation based on an inlet NOx of 25 ppmvd, we can guarantee Outlet NOx of 2.0 ppmvd and NH_3 slip of 5.0 ppmvd.
The guarantees are valid from 0 to 100% load as long as the SCR operating temperature is above the minimum required.

Sincerely,

R. Yoshida

If you did not receive all pages correctly, please notify us by phone: 714-640-4664 or fax: 714-640-6945 / 6947.

This message is intended for the use of the individual or entity which it is addressed and may contain information that is privileged and confidential. Unless you are the addressee or authorized to receive for the addressee, you may not copy, use or distribute it. If you have received this in error, please advise Mitsubishi Heavy Industries America immediately by phone or fax and return it promptly by mail. Thank you.

PEERLESS MFG. CO.

2819 Walnut Hill Lane • Dallas, Texas 75229 • (214) 357-6181 • FAX: (214) 351-0194

FACSIMILE MESSAGE

TO: Dr. Phyllis Fox
ATTN:
FAX: (510) 845-0983
RE: **SCR for GE Frame 7FA variable load**
Your Reference:
Peerless Reference: PMC-2134

DATE: August 13, 1998
PAGES: One (1)
CC: TTS/PMC-2134

Dear Ms. Fox,

Regarding our recent conversations, Peerless Mfg. Co. can supply and guarantee an SCR system to operate at the following conditions for the referenced GE Frame 7FA:

25 ppmvd NO_x inlet
2 ppmvd NO_x outlet
5 ppmvd NH_3 slip
NG operation (back up #2 oil acceptable)
Variable load changes limited by temperature range below
3-hr averaging
Absolute temperature range 400-785°F (Optimal 650-700°F for 100% load)

Based on the stringent design requirements of this system, care must be taken in the overall design. The CEM analyzers must be extremely accurate. This will directly affect the performance of the SCR. A one (1) ppm error on the NO_x analyzer means a 33% error. If the analyzer is reading 3.5ppm (actual is 2.5ppm), it will relay a signal to the Ammonia Flow Control Unit (AFCU) to inject more ammonia, thinking it needs more to reach 2.5ppm. Since more ammonia will be injected than needed, the ammonia slip requirement may be exceeded. So, you can see the importance of the accuracy of the analyzers, especially with low outlet requirements.

Also, the ammonia distribution becomes more stringent. Therefore, the system requires optimum design of the Ammonia Injection Grid (AIG). Peerless specializes in AIG design. We have approximately 100 units installed at more than 65 facilities in the U.S.

We are obtaining heat up time required for the catalyst and will forward the information soon. If you have any questions or need any additional information, please call.

Best Regards,

Tim T. Shippy

J:\SCR\SALES\QUOTES\2100-215.0\2134\PF8-13.FAX

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"Equal Opportunity Employer M/F"

FAX COVER SHEET

ENGELHARD

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE: August 13, 1998 NO. PAGES 2 (INCLUDING COVER)

TO: J. Phyllis Fox

FROM: Fred Booth Ph 410-569-0297 // FAX 410-569-1841

"CONFIDENTIALITY NOTICE"

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RE: Your request of August 12, 1998
Guaranteed SCR Performance

We have summarized data provided for our review and illustrate herein.

Engelhard can indeed provide Guaranteed Performance as noted. Please note that we have assumed temperature at the catalyst. We have assumed the SCR Catalyst to be within the HRSG. Actual catalyst volume may vary as a result of actual temperature at the catalyst inside the HRSG.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

J. Phyllis Fox
August 13, 1998

GIVEN // CALC. DATA			
CASE	1	2	3
AMBIENT	20	20	20
FUEL	NG	NG	NG
LOAD	BASE	75%	50%
TURBINE EXHAUST FLOW, lb/hr	3,604,162	2,981,003	2,879,624
TURBINE EXHAUST GAS ANALYSIS, % VOL.	1001.16	828.06	799.90
N_2	74.78	74.79	75.32
O_2	12.42	12.24	13.73
CO_2	3.88	3.97	3.29
H_2O	7.98	8.06	6.72
Ar	0.94	0.94	0.94
CALCULATED GAS MOL. WT.	28.45	28.45	28.53
GIVEN: TURBINE NOx, ppmvd @ 15%O_2	25	25	45
CALC.: TURBINE NOx, lb/hr	168.2	142.5	204.2
GAS TEMP. @ SCR CATALYST, F (+/-20)	650	650	600
DESIGN REQUIREMENTS			
NOx OUT, ppmvd@15%O_2	2	2	2
NH_3 SLIP, ppmvd@15%O_2	5	5	5
SCR PRESSURE DROP, "WG - Max.			
GUARANTEED PERFORMANCE DATA			
NOx CONVERSION, % - Min.	92.0%	92.0%	95.6%
NOx OUT, ppmvd@15%O_2 - Max.	2	2	2
NOx OUT, lb/hr - Max.	13.5	11.4	9.1
EXPECTED 28% AQUEOUS NH_3 FLOW, lb/hr	249	211	287
NH_3 SLIP, ppmvd@15%O_2 - Max.	5	5	5
SCR PRESSURE DROP, "WG - Max.			

FAX COVER SHEET

ENGELHARD

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	August 13, 1998	NO. PAGES	4	(INCLUDING COVER)
TO:	J. Phyllis Fox			
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841		

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We illustrate additional data to consider control of NOx during initial start-up.

Please note base design for 3,600,000 lb/hr gas flow, 2 ppm NOx out with 5 ppm ammonia slip. Please note that design ammonia flow is 287 lb/hr.

Assume that ammonia system is provided with capability of 300 lb/hr - per system. Considering using dual ammonia system during initial start-up - 600 lb/hr capability. We illustrate expected performance with both one and two ammonia systems.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

August 13, 1998

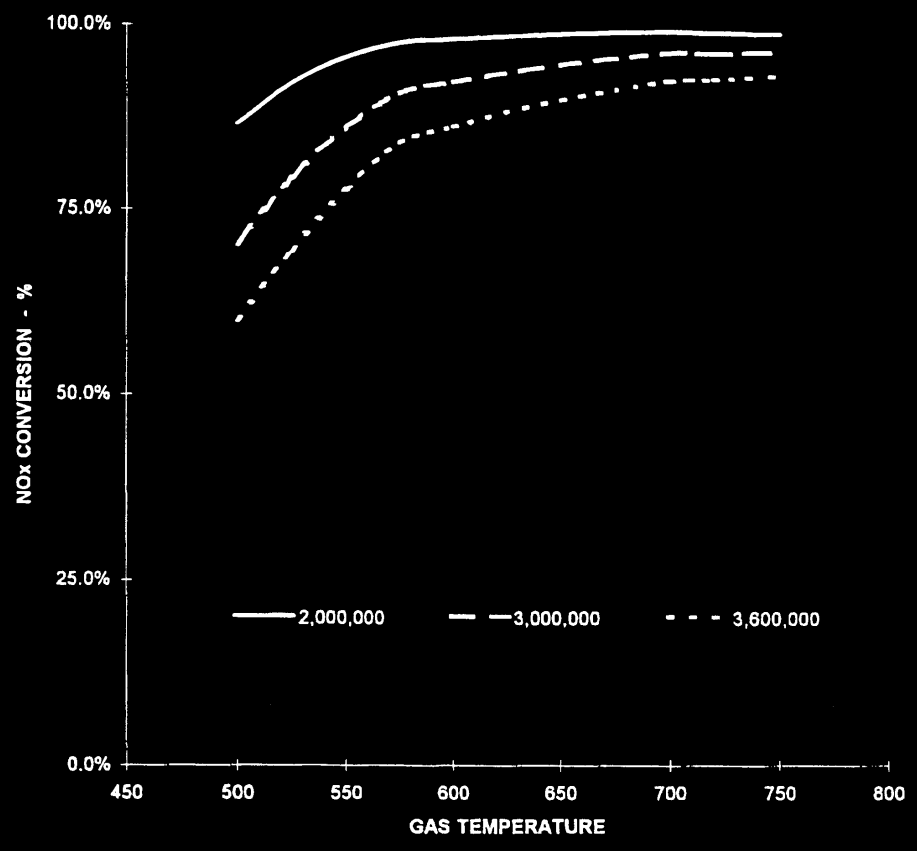
The SCR Catalyst was sized based on the following:

GIVEN // CALC. DATA			
CASE	1	2	3
AMBIENT	20	20	20
FUEL	NG	NG	NG
LOAD	BASE	75%	50%
TURBINE EXHAUST FLOW, lb/hr	3,604,162	2,981,003	2,879,624
TURBINE EXHAUST GAS ANALYSIS, % VOL.	1001.16	828.06	799.90
N_2	74.78	74.79	75.32
O_2	12.42	12.24	13.73
CO_2	3.88	3.97	3.29
H_2O	7.98	8.06	6.72
Ar	0.94	0.94	0.94
CALCULATED GAS MOL. WT.	28.45	28.45	28.53
GIVEN: TURBINE NOx, ppmvd @ 15%O_2	25	25	45
CALC.: TURBINE NOx, lb/hr	168.2	142.5	204.2
CALC.: NOx - ppmv	28.9	29.6	44.0
GAS TEMP. @ SCR CATALYST, F (+/-20)	650	650	600
DESIGN REQUIREMENTS			
NOx OUT, ppmvd@15%O_2	2	2	2
NH_3 SLIP, ppmvd@15%O_2	5	5	5
SCR PRESSURE DROP, 2.5"WG - Max.			
GUARANTEED PERFORMANCE DATA			
NOx CONVERSION, % - Min.	92.0%	92.0%	95.6%
NOx OUT, ppmvd@15%O_2 - Max.	2	2	2
NOx OUT, lb/hr - Max.	13.5	11.4	9.1
DESIGN INLET ALPHA - NH_3:NOx	1.12	1.12	1.07
EXPECTED 28% AQUEOUS NH_3 FLOW, lb/hr	249	211	287
NH_3 SLIP, ppmvd@15%O_2 - Max.	5	5	5
NH_3 SLIP, ppmv	5.8	5.9	4.9
SCR PRESSURE DROP, "WG - Max.			

ENGELHARD

August 13, 1998

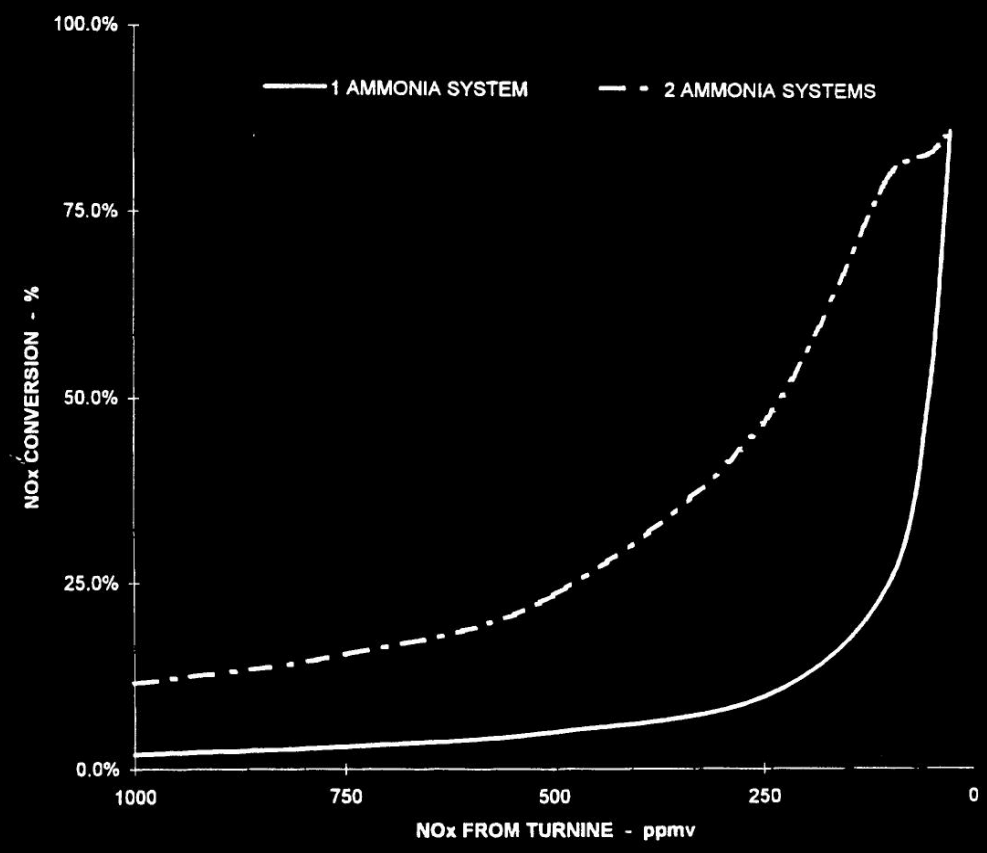
SCR Catalyst Performance
Varying Gas Flow and Gas Temperature
Ammonia Slip - 5 ppmv



ENGELHARD

August 13, 1998

Start-Up Performance
2,000,000 lb/hr Gas Flow
500°F Gas Temperature
One and Two Ammonia Systems
Ammonia Slip - 5 ppmv Max.



HITACHI AMERICA, LTD. 660 White Plains Road Tarrytown, NY 10591

Fax

Date: 8/13/1998

Number of pages including cover sheet: 1

To:	Environmental Management
Attn:	Phyllis Fox
Regarding:	Catalyst Information
Phone:	510-843-1126
Fax phone:	510-845-0983
CC:	D. Brozek (HAL)

From:

John Calvello
Sales Engineer
Power and Industrial Division

Phone:	(914) 524-6631
Fax phone:	(914) 332-5388

REMARKS: ☐ Urgent ☒ For your review ☐ Reply ASAP ☐ Please comment

In response to your talks with David Brozek on Thursday, 8/12, following is some information I can provide in regards to your request. It would take me additional time to gather additional information from Japan and prepare details as you have requested.

In regards to efficiency levels you are requesting we have a plant in Japan that is running at a 93% efficiency level, NOx out of 3ppm, and an ammonia slip of 3ppm. The plant is Yokohama 8, which consists of 4units, frame 9 gas turbines. I have attached some design data on this plant for your reference.

There are two plants going under construction in the southeast U.S.. The first plant is schedule to go online in August/September 1999. The outlet requirements for this plant are 2ppm with an ammonia slip of 10ppm. The second plant is scheduled for 2000. The outlet NOx has not been confirmed yet. The options for this plant are for 2, 3.5, and 4ppm. I should have confirmation on the required level by the end of September.

In general, there is no problem in supplying guarantees to meet both a 2ppm NOx outlet and an ammonia slip of 5ppm. The only consideration is the overall capital cost. These levels can be met by increasing the catalyst volume. I will try to gather additional information on temperature thresholds and operating temperatures for you.

We have recently quoted a confidential project that is to occur in the Northeast. It will be approximately 2000MW facility. I believe they will utilize Westinghouse 501G GT. The requirements quoted were a 3.5 and 2ppm outlet NOx with an ammonia slip of 5ppm or less. Budgetary equipment and catalyst cost are as follows;

Catalyst, Ammonia Injection Grid, Ammonia flow control skid, Catalyst support structure, Outer reactor housing:
3.5ppmvd - $1,700,000. OR 2.0ppm - $1,950,000.
ONE SYSTEM

I hope this current information is helpful. If there are any questions please feel free to contact me.

Sincerely,

John Calvello

0 ー(1) 現在、計画、試運転中の脱硝装置計画仕様

YOKOHAMA 8

	No.	項目	明先	CONFIDENTIAL 計画	CONFIDENTIAL 実績	CONFIDENTIAL 計画	CONFIDENTIAL 実績	YOKOHAMA 8 計画	YOKOHAMA 8 実績	CONFIDENTIAL 計画	CONFIDENTIAL 実績	CONFIDENTIAL 計画	CONFIDENTIAL 実績
CAPACITY	1	ボイラ型式 (出力)	(MW)	700 (4軸)		670 (3軸)		1400 (4軸)		1550 (7軸)		168 (1軸)	
FUEL	2	燃料 (S分)	(wt%)	LNG (0)		LNG (0)		LNG (0)		LNG (0)		[illegible] (7 [illegible])	
GAS FLOW RATE	3	処理ガス量	Nm³/h	(0℃) 1.050.410×4基		(4℃) 1.259.300×3基		(0℃) 1.827.000×4基		1.272.840 (0℃)		1.230.260 (0℃)	
GAS TEMP.	4	処理ガス温度	℃	334		337		339		334			
OPERATION START	5	運転開始	-	1994-1.3 (1.2 軸)		1995-12~ 1996-7		1996-7~ 1998-7		1996-7~ 1997-1		1993-6	
	6												
INLET NOx	7	入口NOx濃度	ppm	52.5(16%O₂)		64.3(16%O₂)		43(16%O₂)		50(16%O₂)		62.5(16%O₂)	
OUTLET NOx	8	出口NOx濃度	ppm	12.5(16%O₂)		9.7(16%O₂)		3(16%O₂)		6(16%O₂)		6.25(16%O₂)	
EFF.	9	脱硝率	%	>80		85		93		88		90	
MOLE RATIO	10	NH₃/NOxモル比	-	0.9082		0.9095		1.0					
	11	Slip NH₃	ppm	10(30)		5 (30)		3(16%O₂)		5(16%O₂)		10(16%O₂)	
	12	SOx (SO₂)	ppm	0		5		0		0		0.2(0.32)	
DUST	13	ダスト	mg/Nm³	0		0		0		0		0	
	14	O₂ (H₂O)	%	13.6 (7.5)		14.0 (7.4)		13.9 (7.3)		13.8 (7.2)		14.5 (6.9)	
	18	LV (LVA)	m/SEC	7.2(8.7)		6.2(8.1)		7.0(8.4)		6.8(8.2)		9.7(11.7)	
	20	H Cata	m	2.5		2.0		2.5		2.75		2.3	
	21	全ΔP (Cata含)	mAq	<100		<120		<75		<100		<120	
	22	ΔP Cataのみ	mAq										
	23	SO₂酸化率	%										
	24	ΔSO₂	ppm										
	25	運転条件	-										
	27	ユニット容量×長行数×段数	個/基	(16"×28")×5ᴸ=2080		(20"×28")×4ᴸ=2240		(20"×33")×5ᴸ=3300		(18"×30")×5ᴸ=2700		(10"×37")×6ᴸ=2220	
	28	ユニット総数	個	2080×4=8320		2240×3=6720		3300×4=13200		2700×7=18900		2220×1=2220	
	28-1	流れ方向のユニット配列	個	3. 2. (1)		2. 2. (1)		3. 2		3. 2. (1)		3. 3	
	29	脱硝装置の運用	℃										
	30	R/C サイズ	m	(12.5"×14.2")×7ᴸ		(11.2"×15.0")×7.5ᴸ		(13.5"×18.6")×7ᴸ		(10.1"×16.6")×7.5ᴸ		(5.5"×18.9")×7.5ᴸ	
	31	重量: CATA+R/C	TON										
	32	脱硝率DENOx=100-	-										
FRAME TYPE	33	備考		F7F		F7FA		F9F		F7FA		F9EA	

(EI5000)

MITSUBISHI HEAVY INDUSTRIES AMERICA, INC.
Power Systems Division / Los Angeles Office
660 Newport Center Drive, Suite 1000
Newport Beach, CA 92660

FACSIMILE MESSAGE

DATE: April 30, 1998

TO: Patch Incorporated
Attn. Mr. Patch
Phone : 707-435-9994
Fax : 707-435-9988

COPY TO: Mr. Taki, Mr. Onishi

FROM: Ricardo Yoshida
Senior Project Engineer
Phone : 714-640-5941
Fax : 714-640-6945 / 6947

MHIA REF. #: LA- 1202S MHIA Project #: LA-223

SUBJECT: SCAQMD BACT

REFERENCE: NOx Levels

Number of pages including cover sheet: 19

Dear Mr. Patch,

1. Below table shows the budget price of one (1) SCR System for different requirements. All pricing is based on conventional SCR System. DeNOx Efficiency above 92% would require an optimization using CFD and Cold Flow Model Test which were not used at this time therefore our prices for cases 3 & 4 are conservative.

Case	NOx Removal	Outlet NOx	SCR Material Cost
1	88 %	3.0 ppm	$1,251,000.00
2	90 %	2.5 ppm	$1,314,000.00
3	92 %	2.0 ppm	$1,449,000.00
4	94 %	1.5 ppm	$1,782,000.00

2. For clarification on the scope of work and supply, please refer to our technical specification.
3. We assumed and recommend the electric heater type skid for this application. This system has less restriction during start up.
4. With regard to experience, MHIA has supplied the SCR System for Simpson Paper. This unit has a gas turbine with retrofitted low NOx combustors. The Inlet NOx is around 14-15

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ppmvd and the Outlet NOx is less than 2 ppmvd. Based on this, we confirm that the 2.5 ppmvd will be met with the current SCR technology.

5. Our experience in Japan can not be disclosed in details at this moment because there is no licensee agreement between MHI and MHIA for this technology. The current units operating in Japan at very low NOx levels were co developed with other companies therefore it will take a time until an agreement is in place. However MHI is building a Combined Cycle Unit in Japan (Shin Chiba) with 2.5 ppm NOx outlet, this plant will start operation next year.

Sincerely,