California Environmental Protection Agency

AIR RESOURCES BOARD

Guidance for Power Plant Siting and Best Available Control Technology

Stationary Source Division

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Guidance for Power Plant Siting and Best Available Control Technology

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EXECUTIVE SUMMARY

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

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[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.

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, and 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 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 away 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 twenty-two thousand megawatts 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 five hundred to a thousand megawatts. 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. The 35 projects being proposed, or anticipated, to date would provide an additional 22,000 MW, if they are all constructed.

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, 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 oxides of nitrogen (NO_X) and carbon monoxide (CO). The larger projects may also exceed the offset thresholds for particulate matter (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 megawatts 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:

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

C. RECOMMENDATION

Staff recommends that the Board endorse the use of this proposed 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

Best available control technology (BACT) guidelines 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 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 @ 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

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

levels achieved in practice in three consecutive annual source tests.

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 as supplied by a regulated entity	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf as supplied by a regulated entity (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 as supplied by a regulated entity	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf as supplied by a regulated entity (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 available for 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.

a. 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.)

b. Interpollutant and Interbasin Emissions Offset Ratios

Proposed 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 also intends to develop 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: Proposed Minimum Interpollutant Offset Ratios

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

a. 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.

b. 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 be required to have a district-approved plan to minimize emissions from equipment startup and shutdown.

c. Source Testing and Monitoring

The permit should include conditions requiring initial and annual source tests to determine the power plant's compliance with BACT and other emission limits, using certified methods that meet district, State, and federal protocols.

d. 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.

e. 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 @ 15 percent oxygen.

II.

POWER PLANT SITING IN CALIFORNIA

A. 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 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 district's preconstruction permitting program entitled "New Source Review (NSR)." As with non-power plant projects, the district 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.

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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.

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 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

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[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.

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 air pollution control districts and air quality management districts (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 the more stringent of the two federal emission control requirements.[8] 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

[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.

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; 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; 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.

D. 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.

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

The Air Resources Board (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.

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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.

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

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.

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 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, or

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

Staff proposed 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,

use of aeroderived versus industrial frame gas turbine for simple-cycle power plant configuration, 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 as supplied by a regulated entity	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf as supplied by a regulated entity (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 as supplied by a regulated entity	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf as supplied by a regulated entity (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).

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 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.

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[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.

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 NOx 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 NOx levels.

The most stringent BACT limit for an operating combined-cycle gas turbine is 3 ppmvd NOx 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 CEM 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). Upon reviewing this data, the U.S. EPA deemed 2.0 ppmvd NOx 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 NOx 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 NOx 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 generally reduce NOx emissions from duct burners using 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.

Staff has identified a number of power plant projects with proposed emissions below the achieved in practice level of 2.5 ppmvd NOx 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 NOx 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 NOx 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 NOx at 15 percent oxygen averaged over 1 hour. Both power plants will consist of two 180 MW ABB GT-24 gas turbines. The NOx emission level is 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 CEMS 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 NOx 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.

Due to acute health effects, ammonia is a listed toxic air contaminant in California. As a result, it 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).

Ambient $PM_{2.5}$ 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 $PM_{2.5}$ 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 BACT 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 @ 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 NOx BACT for a simple-cycle gas turbine was required in the preconstruction permit for Carson Energy Group in Sacramento County, California, at 5 ppmvd NOx 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 NOx emission limit in three consecutive years of source testing. Considering that the Carson Energy Group represents the most stringent NOx BACT which has been achieved in practice, staff recommends BACT for NOx emissions from simple-cycle gas turbines is 5 ppmvd at 15 percent oxygen averaged over 3 hours.

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 NOx at 15 percent oxygen using 1-hour averaging, achieved using dry low-NOx burners and selective catalytic reduction.

Emission levels of 2.0 ppmvd NOx 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 NOx 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 NOx BACT level is being proposed for five other large combined-cycle and cogeneration power plant projects currently

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

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

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.

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 limit of 5.93 pounds CO per hour (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 average 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 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. 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

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

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.

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 Public Utilities Commission (PUC)-regulated 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.

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 pounds per hour 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 grain of total sulfur per 100 standard cubic feet (gr/100 scf) specified in the local gas utility company purchase contracts.

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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.

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/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.

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/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**.**

e. BACT Recommendation

The lowest PM_{10} emissions from gas turbines are achieved through combustion of Public Utilities Commission (PUC)-regulated natural gas along with combustion design that minimizes NOx 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.[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 grain per 100 standard cubic feet of total sulfur delivered by an entity regulated by the PUC. 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/dscf. Furthermore, there are "housekeeping measures" that can prevent emissions from the lube oil vent, including a lube oil vent coalescer and an associated opacity

[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.

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.

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.

In addition, the South Coast Air Quality Management District Rule 431 limits the sulfur content of natural gas to 16 ppmvd S as H_2S. The corresponding worst-case SOx emissions are approximately 0.55 ppmvd as SO_2 at 15 percent oxygen.

b. Control Techniques Required as BACT

SOx 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 grain of total sulfur per 100 standard cubic feet (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 grain per 100 standard cubic feet of total sulfur 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/100 scf for gaseous fuels assuming full conversion of fuel sulfur to sulfur dioxide.

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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.

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 grain per 100 standard cubic feet of total sulfur, 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 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 heat recovery steam generator. 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.

e. BACT Recommendation

SOx emissions result from the oxidation of fuel sulfur during combustion. Staff is unaware of combustion or add-on controls feasible for controlling SOx emissions from gas turbines. Therefore, staff recommends a SOx BACT limit equivalent to emissions caused by combusting gaseous fuel with a sulfur content of 1 gr/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 turbines power plant 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 4 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-NOx combustor technology (These include XONON, which can achieve 3 ppmvd NOx 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

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 NO_X and carbon monoxide (CO); however, most areas in California have been designated attainment with the federal and State carbon monoxide (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 PM_{10}, 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 ARB. To the extent allowed by a district's rules 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 operating scenario identified for each pollutant emitted.

[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."

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 emissions 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 emissions 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.

C. 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 proposed minimum interpollutant offset ratios in Table IV-1 are based on recent and past staff assessments of interpollutant relationships; staff also intends to develop 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 is proposing interbasin pollutant offset ratios specified in Table IV-2. The proposed 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: Proposed Minimum Interpollutant Offset Ratios

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

Table IV-2: Proposed 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 attainment or maintenance of any applicable ambient air quality standard, consistent with Section 42301 of the Health and Safety Code.

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[19]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.

a. 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 will be 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 can not be less than 1.0:1.

Staff proposes to develop 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 volatile organic compounds (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.

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[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 ($PM_{2.5}$), 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 can not be used where the offsetting pollutant contributes to the violation of another standard. For example, NO_X increases can not be offset with PM_{10} reductions in an ozone nonattainment area and, upon implementation of requirements, $PM_{2.5}$ increases can not 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 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

[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.

[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."

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 proposed 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 proposed 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 proposed 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

A. 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.

B. 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.

C. 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.

D. 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 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 AQMD 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 ARB's "Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants, July 1993."

B. 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, and 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 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

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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.

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, and 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, 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 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

A. OVERVIEW

Power plant permitting in California remains a complex process despite the consolidated 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.

B. GENERAL PERMITTING CONSIDERATIONS

In California, the local air 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 (40 CFR Parts 72 through 77 and Part 70, respectively) for the applicable requirements, and any applicable guidance prepared by the U.S. EPA.

C. 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 and ammonia slip with selective catalytic reduction of 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., 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 emission assumption should be enforceable through an emission limit in the permit; otherwise, 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)

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 difficult to enforce, especially if determination of emissions requires evaluation of extensive records and complex calculations. Instead, permit conditions should limit annual emissions from each emission unit at the facility. The 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.

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. 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

Initial and annual source tests should be required to determine the power plant's compliance with BACT and other emission limits specified in permit conditions. 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 web site, or the ARB's web site.[26] If CEMs are required, initial 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; the 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 BTU content, RPM, load, electrical energy produced, ambient air temperature and pressure, injection rates (if applicable) and other operating parameters. Annual source testing should be required 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 initial and annual source testing:

> pollutants to be tested, operating parameters, frequency of source testing (at least initial and annually thereafter), 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 oxides of nitrogen (NOx), carbon monoxide (CO), volatile organic compounds (VOC), flue gas oxygen content (O_2), and, if applicable, ammonia (NH_3). Annual source testing is appropriate to determine compliance with emission limits for SO_X and PM_{10}; 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.

4. Fuel Sulfur Content

The combustion of fuels containing sulfur results in the emission of oxides of sulfur (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 requirement for annual source testing using an appropriate test method,

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.).

4. 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 annual source testing and 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 @ 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

A. 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. 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

BACT emission limits must not be less stringent than New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants

[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.

(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 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

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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.

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 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. Air Resources Board 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

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[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.

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

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

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[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.

RACT/BACT/LAER Clearinghouse website, individual state websites, or by contacting each state directly.[5]

Step 4. Control Technologies More Stringent Than Those 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

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

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[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.

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