SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

FINAL ENVIRONMENTAL ASSESSMENT FOR:

PROPOSED RULE 1304.1 – ELECTRICAL GENERATING FACILITY FEE FOR USE OF OFFSET EXEMPTION

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Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Authors:	Jeff Inabinet	Air Quality Specialist, CEQA
	Mike Krause	Program Supervisor, CEQA
Technical Assistance:	Robert Pease	Program Supervisor
	Henry Pourzand	Air Quality Specialist
Reviewed By:	Naveen Berry	Planning and Rules Manager
	Robert Pease	Program Supervisor
	Barbara Baird	Chief Deputy Counsel
	Veera Tyagi	Senior Deputy District Counsel
	Lauren Nevitt	Senior Deputy District Counsel

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BARRY R. WALLERSTEIN, D.Env.

PREFACE

This document constitutes the Final Environmental Assessment (EA) for Proposed Rule (PR) 1304.1 – Electrical Generating Facility Fee For Use of Offset Exemption. The Draft EA was released for a 45-day public review and comment period from July 9, 2013 to August 22, 2013. One comment letter was received from the public on the Draft EA. This comment letter, along with responses to the comments, is included in Appendix F of this document.

Subsequent to release of the Draft EA, minor modifications were made to PR 1304.1. To facilitate identification, modifications to the document are included as underlined text and text removed from the document is indicated by strikethrough. Staff has reviewed the modifications to PR 1304.1 and concluded that none of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. As a result, these minor revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5. Therefore, this document now constitutes the Final EA for PR 1304.1

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CHAPTER 1

INTRODUCTION AND EXECUTIVE SUMMARY

INTRODUCTION

The California Legislature adopted the Lewis-Presley Air Quality Act in 1976, creating the South Coast Air Quality Management District (SCAQMD) from a voluntary association of air pollution control districts in Los Angeles, Orange, Riverside, and San Bernardino counties. The new agency was charged with developing uniform plans and programs for the South Coast Air Basin (Basin) to attain federal air quality standards by the dates specified in federal law. While the Basin has one of the worst air quality problems in the nation, there have been significant improvements in air quality in the Basin over the last three decades. Still, some air quality standards are exceeded relatively frequently, and by a wide margin. The agency was also required to meet state standards by the earliest date achievable through the use of reasonably available or all feasible control measures.

The South Coast Air Quality Management District (SCAQMD) is proposing to adopt a new rule, Proposed Rule (PR) 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption. If adopted, PR 1304.1 would require any electrical generating facility (EGF) that elects to use the specific offset exemption described in SCAQMD Rule 1304 (a)(2) - Electric Utility Steam Boiler Replacement, to pay fees for up to the full amount of offsets provided by the SCAQMD. Offsets in SCAQMD internal accounts are valuable public goods and are a specific benefit conferred to the eligible EGFs. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets pursuant to the requirements in Rule 1304 (a)(2). Because the fee is based on historical values of the offsets in the market, it is a reasonable cost of conferring the benefit.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

Pursuant to the California Environmental Quality Act (CEQA), this Draft Environmental Assessment (EA) has been prepared to address the potential environmental impacts associated with the South Coast Air Quality Management District's adoption of Proposed Rule 1304.1. Proposed Rule 1304.1 comprises a "project" as defined by CEQA (Cal. Public Resources Code §21000, *et. seq*.). The SCAQMD is the lead agency for the proposed project and has prepared an appropriate environmental analysis pursuant to its certified regulatory program under California Public Resources Code §21080.5. That statute allows public agencies with certified regulatory programs to prepare a plan or other written document that is the functional equivalent of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of the Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Cal. Public Resources Code § 21000 *et seq*., requires that the potential environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid identified significant adverse environmental impact from these projects be identified.

SCAQMD staff previously prepared an initial study (IS) and concluded that an EIR or EIR-equivalent CEQA document was warranted. The IS, along with a Notice of Preparation (NOP), was circulated for a 30-day public review period to solicit comments from public agencies and the public in general, on potential impacts from the proposed project. Two comment letters were received by the SCAQMD during the public comment period on the NOP/IS. The comment letters and responses are included in Appendix B of this Draft EA.

Previous CEQA Documentation

The original NOP/IS was distributed to responsible agencies and interested parties for a 30-day review and comment period on April 9, 2013. The NOP/IS identified potential adverse impacts in the following environmental topics: air quality and greenhouse gas emissions and energy. This Draft EA also includes detailed responses to the two comment letters that were received on the NOP/IS (Appendix B). An Environmental Assessment was also prepared for the 2012 Air Quality Management Plan (AQMP) which analyzed the proposed control measures. Fees generated by the proposed project would be invested in air pollution control projects that further the goals of the 2012 AQMP

Intended Uses of this Document

In general, a CEQA document is an informational document that informs a public agency's decision-makers and the public generally of potentially significant environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project (CEQA Guidelines §15121). A public agency's decision-makers must consider the information in a CEQA document prior to making a decision on the project. Accordingly, this Draft EA is intended to: a) provide the SCAQMD Governing Board and the public with information on the environmental effects of the proposed project; and, b) be used as a tool by the SCAQMD Governing Board to facilitate decision making on the proposed project.

AREAS OF CONTROVERSY

In accordance with CEQA Guidelines §15123 (b)(2), the areas of controversy known to the lead agency, including issues raised by agencies and the public, shall be identified in the CEQA document. The following discussion identifies the areas of controversy that have been raised relating to PR 1304.1.

The purpose of PR 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption, is to require EGFs which elect to use a specific offset exemption to pay annual fees or a single payment for the amount of offsets provided by the SCAQMD. The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 AQMP.

The main area of controversy raised by EGFs is that the proposed fee would make potential boiler replacement projects more expensive and thus could potentially lead to the delay, downsizing, or abandonment of these types of projects. If boiler projects are delayed, downsized, or abandoned, EGFs may have to continue operating their aging, less efficient boilers which could result in forgoing a reduction in emissions from not replacing earlier. If old boilers are not replaced, potential electricity demand or load increases which would require increasing amounts of local generating capacity may not be met, and therefore, could cause adverse impacts on the local and Basin-wide electrical system reliability. Because this issue was raised by several local municipalities, this environmental assessment will analyze whether the proposed project has the potential to result in emissions benefits foregone.

EXECUTIVE SUMMARY

Chapter 2 – Project Description and Project Objectives

The purpose of PR 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption, is to require any EGF that elects to use a specific offset exemption (Rule 1304 (a)(2)) to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Offsets in SCAQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304 (a)(2). The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 AQMP and reduce emissions of pollutants for which the fee is charged or their precursors or pollutants to which they contribute.

The proposed rule affects all EGF's that elect to use the offset exemptions described in Rule 1304 (a)(2), but not those facilities that meet their emissions obligations through privately held/procured emission reduction credits (ERCs).

The project objectives are as follows:

- Recoup the fair market value of offsets provided to eligible EGFs from SCAQMD's internal offset bank pursuant to offset exemption Rule 1304 (a)(2) ~~that is a reasonable cost for conferring the benefit~~;
- Facilitate the continued development of a reliable electric grid within the SCAQMD's jurisdiction while discouraging electric generation not necessary to serve native load or reliability needs.
- Reduce the depletion rate of offsets from SCAQMD's internal offset bank <u>to ensure the continued availability of offsets for essential public services;</u> and,
- ~~Utilize funds~~ <u>Maximize the availability of funds</u> for investment in air pollution reduction projects ~~furthering~~ <u>that further</u> the goals outlined in the 2012 AQMP.

Chapter 3 – Existing Setting

Pursuant to the CEQA Guidelines §15125, Chapter 3 – Existing Setting, includes descriptions of those environmental areas that could be adversely affected by the proposed project as identified in the NOP/IS (Appendix B). The following subsection briefly highlights the existing setting for the topics of air quality and energy which have been identified as having potentially significant adverse affects from implementing the proposed project.

<u>Air Quality</u>

This section provides an overview of air quality in the district whose region could be affected by the proposed project. Air quality in the area of the SCAQMD's jurisdiction has shown substantial improvement over the last two decades. Nevertheless, some federal and state air quality standards are still exceeded frequently and by a wide margin. Of the National Ambient Air Quality Standards (NAAQS) established for seven criteria pollutants (ozone, lead, sulfur dioxide, nitrogen dioxide, carbon monoxide, PM10 and

PM2.5), the area within the SCAQMD's jurisdiction is only in attainment with carbon monoxide, sulfur dioxide, and nitrogen dioxide standards. Air monitoring for PM10 indicates that SCAQMD has attained the NAAQS and the USEPA published approval of SCAQMD's PM10 attainment plan on June 26, 2013, with an implementation date of July 26, 2013. Effective December 31, 2010, the Los Angeles County portion of the SCAQMD has been designated as non-attainment for the new federal standard for lead, based on emissions from two specific facilities. Chapter 3 provides a brief description of the existing air quality setting for each criteria pollutant, as well as the human health effects resulting from exposure to each criteria pollutant. In addition, this section includes a discussion on greenhouse gas (GHG) emissions, climate change and toxic air contaminants (TACs).

Energy

This section describes the existing regulatory setting relative to energy production and demand, including alternative and renewable fuels, and trends within California and the District.

Currently, pursuant to Rule 1304 (a)(2), a replacement of an Electrical Utility Steam Boiler (EUSB) at an EGF is exempt from the modeling and offset requirements of Rule 1303 (b)(2). The exemption is specifically limited to EUSBs that utilize combined cycle gas turbines, intercooled, chemically-recuperated gas turbines, other advanced gas turbines, solar, geothermal, or wind energy or other equipment to the extent that such equipment will allow compliance with Rule 1135 - Emissions of Oxides of Nitrogen from Electric Power Generating Systems or Regulation XX – Regional Clean Air Incentives Market (RECLAIM). In order to demonstrate compliance with the federal New Source Review (NSR) program, which does not provide for an exemption from offsets as contained in Rule 1304 (a)(2) for EUSB replacement projects, the SCAQMD provides offsets from its internal offset accounts, as described in Rule 1315. No fee is being charged currently for the provision of offsets from the internal offset accounts.

Chapter 4 – Environmental Impacts

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2 (a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The following subsection briefly highlights the environmental impacts and mitigation measures for the topics of air quality and energy which have been identified as having potentially significant adverse effects from implementing the proposed project. In an effort to address potential impact on electricity reliability and corresponding air quality impacts from PR 1304.1, the SCAQMD retained a professor and economist from Stanford University, Dr. Frank Wolak, with an expertise in the California power markets to analyze potential impact of the proposed fee on the repowering needs of the Los Angeles area.

Air Quality

This section provides an overview of the potential adverse air quality and GHG emissions impacts from the proposed project. Based on a combination of regulatory requirements, economic drivers to repower, as described in Dr. Wolak's report "An Economic and

Reliability Analysis of the Proposal to Assess a Fee to Access the South Coast Air Quality Management District's Offset Bank," (Appendix D) that addresses electrical grid reliability and economic concerns, the proposed fee is very unlikely to change the decision to repower for affected EGFs. However, it is possible that one or more municipal utilities could potentially choose to delay repowering their equipment for reasons beyond the economic ones analyzed in Dr. Wolak's report. This document therefore analyzes the potential environmental impact of such decisions. In addition, existing boilers could operate at a higher capacity to handle additional energy needs during the delay, if any.

As noted in the report (page 9), "Although municipal utilities, such at the Los Angeles Department of Water and Power (LADWP), City of Glendale Water and Power (GWP), and Burbank Water and Power (BWP) are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and long term procurement plan (LTPP) process. Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts."

The report continues to state "LADWP prepares an IRP annually with a 20-year timeframe to ensure that current and future energy needs of the City of Los Angeles are met. Similar to the CPUC LTPP, LADWP's IRP process lays out alternative strategies for meeting LADWP's energy supply and environmental policy goals, while maintaining a reliable supply of energy and minimizing the financial impact on their ratepayers. In its 2007 IRP, the City of Glendale considered at 10-year planning horizon and concluded that "GWP Has Sufficient Resources to Meet Expected Peak Loads Through the Period Covered by this IRP." In its 2006 IRP, BWP considered a 20-year planning horizon and concluded that "BWP plans to meet substantially all of its load growth requirements over the next 20 years with a combination of energy efficiency measures and renewable energy supplies."

By comparing the emissions from the replacement equipment with boilers operating at maximum capacity on a daily basis, the analysis includes impacts from boilers increasing their load in a "worst case" daily scenario. Under this scenario, PM10, VOC, NOx and GHG emissions would exceed the daily CEQA significance threshold because it is assumed that municipal utilities would delay repowering projects and increase loads from the existing boilers. However, it is unlikely that all projects will be delayed at the same time, and the funding from other project repowering will have co-benefits in reducing GHG emissions. In addition, the anticipated delay will be temporary as backstop measures and the existing regulatory and planning framework will ensure that older equipment will be replaced so as not to cause an inadequate supply of electricity.

By funding air quality improvement programs with the fee from the proposed project, emission reductions will be generated that provide local and regional air quality benefits to reduce the impact of the potential delay in emission reductions from those limited facilities choosing to delay their repower projects because of the fee. Staff has not identified any further feasible mitigation measures that would reduce or eliminate the expected emission reductions foregone.

Energy

This section describes the potential adverse impact to energy production and reliability from the proposed project. An analysis was prepared by Dr. Frank Wolak, Director, Program on Energy and Sustainable Development and Professor, Department of Economics at Stanford University, which concludes there are "many more than adequate safeguards in place to ensure that grid reliability will not be adversely impacted by this decision" (PR 1304.1). See Appendix D for the complete report from Dr. Wolak. Further, there is a regulatory framework and a backstop process that ensure "there are no discernible short-term reliability consequences associated with the imposition of Proposed Rule 1304.1" (page 10). Further, "the CPUC's LTPP process ensures that adequate generation capacity will be available and paid for to avoid any long-term reliability consequences associated with Proposed Rule 1304.1." Thus, the energy impacts from the implementation of the proposed project are expected to be less than significant because the proposed project will not significantly adversely affect reliability of energy supplies, energy demand, or cause a depletion of energy sources.

Chapter 5 – Alternatives

The proposed project and four alternatives to the proposed project are summarized below in Table 1-1: Alternative A (No Project), Alternative B (Higher Fee), Alternative C (Higher Fee for Capacity Relocation Projects) and Alternative D (Lower Fee). Pursuant to CEQA Guidelines §15126.6 (b), the purpose of an alternatives analysis is to reduce or avoid potentially significant adverse effects that a project may have on the environment. A higher fee alternative may provide a reduction of adverse emission impacts because more funds would be available to apply to air quality improvement projects. The environmental topic areas identified in the NOP/IS that may be adversely affected by the proposed project were air quality and energy impacts. A comprehensive analysis of air quality and GHG impacts are included in Chapter 4 of this document. In addition to identifying project alternatives, Chapter 5 provides a comparison of the potential operational impacts to air quality and GHG emissions and energy from each of the project alternatives relative to the proposed project, which are summarized below in Table 1-2. Aside from these topics, no other potential significant adverse impacts were identified for the proposed project or any of the project alternatives. As indicated in the following discussions, the proposed project is considered to provide the best balance between meeting the objectives of the project while minimizing potentially significant adverse environmental impacts.

TABLE 1-1
Summary of PR 1304.1 and Project Alternatives

Project	Project Description
Proposed Project	Requires electric generating facilities (EGFs) that elect to use the specific offset exemption under Rule 1304 (a)(2) to pay a fee for the amount of offsets provided from the SCAQMD internal accounts. The fee can be paid annually or one time up-front, and will be used to recoup the fair market value of offsets procured by eligible EGFs electing to use the offsets to comply with Rule 1304 (a)(2). The fee proceeds will be invested in air pollution improvement projects consistent with the 2012 AQMP.

TABLE 1-1 (Concluded)
Summary of PR 1304.1 and Project Alternatives

Project	Project Description
Alternative A (No Project)	EGFs that use the specific offset exemption under Rule 1304 (a)(2) will continue to not pay for the amount of offsets provided from the SCAQMD internal accounts. The value of the offsets will not be recouped and there will be no additional investment in air pollution improvement projects as a result of this project.
Alternative B (Higher Fee)	Requires EGFs that use the specific offset exemption under Rule 1304 (a)(2) to pay a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable.
Alternative C (Higher Fee for Capacity Relocation)	Requires EGFs that are relocating electrical generation capacity from one facility to another facility for new equipment to be subject to a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable.
Alternative D (Lower Fee)	Requires EGFs that use the specific offset exemption under Rule 1304 (a)(2) to pay a lower fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable. The total value of the offsets will not be recouped and there will be a lower amount for investment in air pollution improvement projects.

TABLE 1-2
Comparison of Adverse Environmental Impacts of the Alternatives

Category	Proposed Project	Alternative A: No Project	Alternative B: Higher Fee	Alternative C: Higher Fee for Capacity Relocation Projects	Alternative D: Lower Fee
Air Quality Impacts – Criteria Pollutants	318 lbs PM10, 258 lbs VOC, and 140 lbs NOx daily delay in emission reductions from potential increase in usage of boilers; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering and no increase in usage of boilers; also, no further emission reductions.	More significant than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more significant than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	Yes	No	Yes	Yes	Yes

TABLE 1-2 (Concluded)
Comparison of Adverse Environmental Impacts of the Alternatives

Category	Proposed Project	Alternative A: No Project	Alternative B: Higher Fee	Alternative C: Higher Fee for Capacity Relocation Projects	Alternative D: Lower Fee
Air Quality Impacts – GHG	235,400 MT/yr annual delay in emission reductions and potential increase in usage of boilers; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering and no increase in usage of boilers; also, no further emission reductions.	More significant than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more significant than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	Yes	No	Yes	Yes	Yes
Air Quality Impacts – Toxics	Less than 1 lb per day daily delay in emission reductions; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering and no increase in usage of boilers; also, no further emission reductions.	More potential adverse impact than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more potential adverse impact than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	No	No	No	No	No
Energy Impacts	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system
Significant?	No	No	No	No	No

Appendix A – Proposed Rule 1304.1
Appendix A contains a complete version of Proposed Rule 1304.1.

Appendix B – Notice of Preparation / Initial Study
SCAQMD staff previously prepared an initial study (IS) and concluded that an EIR or EIR-equivalent CEQA document was warranted. The IS, along with a Notice of Preparation (NOP), was circulated for a 30-day public review period to solicit comments from public agencies and the public in general, on potential impacts from the proposed project. The NOP/IS is included in Appendix B of this Draft EA.

Appendix C – Comment Letters Received on the NOP/IS and Responses to Comments
Two comment letters were received by the SCAQMD during the public comment period relative to the NOP/IS. These comment letters and the responses to comments are included in Appendix C of this Draft EA.

Appendix D – An Economic and Reliability Analysis of the Proposal to Assess a Fee to Access the South Coast Air Quality Management District's Offset Bank by Dr. Frank A. Wolak
The SCAQMD retained Dr. Frank A. Wolak, Director of the Program on Energy and Sustainable Development and Professor in the Department of Economics at Stanford University to conduct an economic and reliability analysis on Proposed Rule 1304.1. Based on the analysis, Dr. Wolak concluded that the District's Proposed Rule 1304.1 is highly unlikely to adversely impact the reliability of the electricity supply in Southern California or in the California ISO control area. The joint CPUC and California ISO resource adequacy process will ensure that the generation units needed to maintain a reliable supply of energy in the state are available. Although municipal utilities, such at the LADWP, GWP, and BWP are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and LTPP process. Each of these municipal utilities produces an IRP to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts. In addition, for virtually all of the cases that generation unit owner would decide to re-power an existing steam boiler without having to pay for the access to the District's offset bank, the cost assessed to access the District's bank would not change the economics of this decision.

Appendix E – Correspondence from Broiles & Timms, LLP
Correspondence was submitted to SCAQMD's rule development staff regarding PR 1304.1 prior to the release of the NOP/IS and the data provided in the correspondence was relied upon to analyze for a "real world" scenario of the potential adverse environmental impacts in Chapter 4 of this Draft EA.

CHAPTER 2

PROJECT DESCRIPTION

Project Location

Project Background

Project Description

Project Objectives

PROJECT LOCATION

The proposed project consists of adopting PR 1304.1. If adopted by the SCAQMD's Governing Board, PR 1304.1 would become part of SCAQMD's Regulation XIII – New Source Review, which regulates new and modified stationary sources of air pollution located within the SCAQMD's jurisdiction (e.g., the entire district).

The SCAQMD has jurisdiction over an area of 10,473 square miles, consisting of the four-county South Coast Air Basin (Basin) and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a sub area of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portions of the SSAB and MDAB are bounded by the San Jacinto Mountains to the west and span eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a sub region of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east. The SCAQMD's jurisdictional area is depicted in Figure 2-1. The proposed project would be in effect in the entire area of the SCAQMD's jurisdiction.

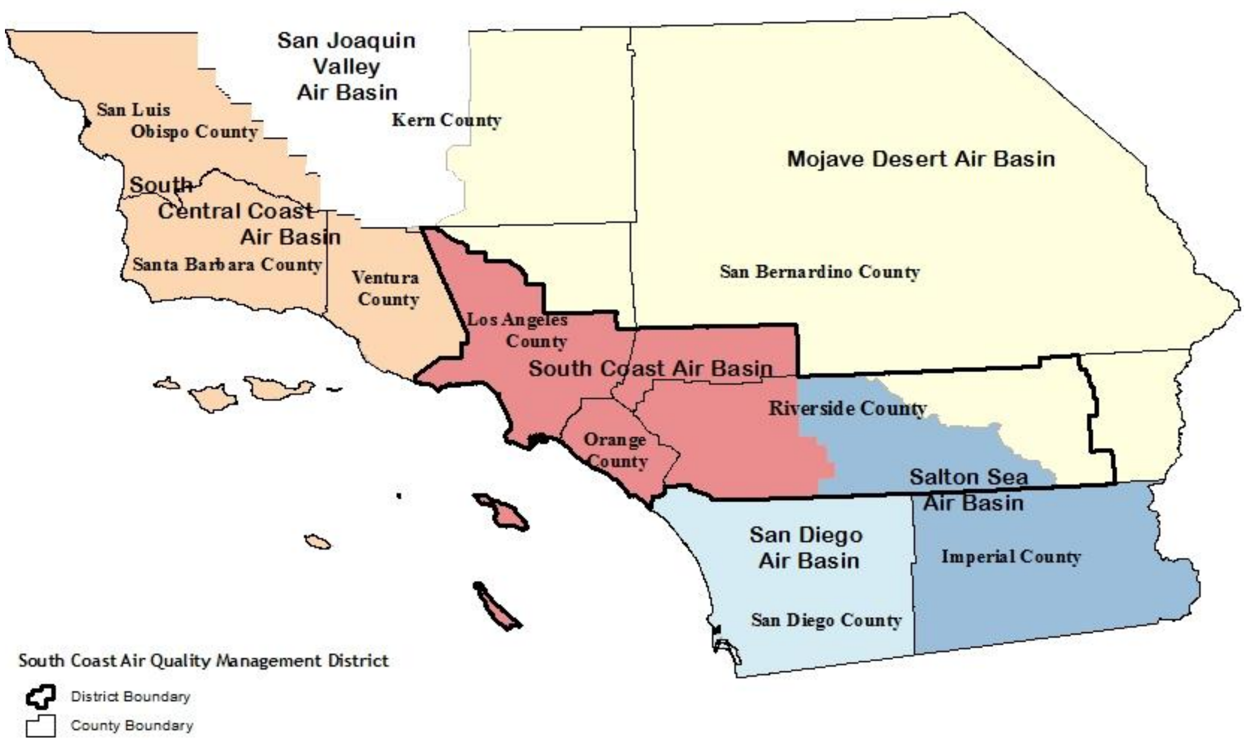


FIGURE 2-1
South Coast Air Quality Management District Boundaries

PROJECT BACKGROUND

New Source Review and the Requirement for Offsets

Under the federal Clean Air Act (CAA), a State Implementation Plan (SIP) for a nonattainment area must include a "New Source Review" (NSR) permitting program for the construction and operation of new and modified "major" stationary sources of air emissions[1]. Included in the California SIP is a minor NSR program for the SCAQMD. Minor NSR programs contain conditions to limit emissions. These requirements do not apply to mobile sources such as cars, trucks and ships. The definition of what constitutes a "major" stationary source under the CAA depends on the extent to which the region in question is in nonattainment for a particular pollutant. The Basin is classified as an "extreme" nonattainment region for ozone and, therefore, the threshold for triggering the NSR requirements for ozone is lower than in the Coachella Valley, which is classified as a "severe" nonattainment area for ozone. It should be noted that the SCAQMD's permitting requirements are broader than the federal NSR requirements in that the SCAQMD's requirements apply to ***all*** stationary sources that would result in a net increase in emissions of any nonattainment pollutant, even if the source does not qualify as a "major" source under the CAA.

The CAA's NSR permitting requirements are designed to ensure that the operation of new, modified, or relocated major stationary emission sources in nonattainment areas does not impede the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS). Under the CAA, all local major NSR permitting programs for nonattainment areas must require the implementation of the lowest achievable emissions rate (LAER). LAER is the most stringent emissions limitation derived from either of the following: 1) the most stringent emissions limitation contained in any state's SIP for the class or category of source at issue, unless it is demonstrated that such a limitation is not achievable; or, 2) the most stringent emissions limitation achieved in practice by that class or source category.

In addition, all local NSR permitting programs for nonattainment areas must require that emissions increases from permitted major sources are "offset" by corresponding emissions reductions[2]. An "offset" is a reduction of emissions in an amount equal to, or greater than, the emissions increase of the same pollutant from the permitted source. Offsets can be created when an operator reduces emissions by shutting down equipment or installing controls, or implementing permanent process changes resulting in emissions reductions that are not required. The specific quantity of the offset that is required under the CAA depends on the degree of nonattainment in the area in question. The SCAQMD's offset requirements are discussed in greater detail below. Lastly, EGFs are considered major sources and, therefore, are subject to NSR and offsetting requirements.

[1] The CAA also establishes permitting requirements for major sources of emissions located in attainment regions, in order to prevent a significant deterioration of air quality in those areas.

[2] The NSR offset requirements are set forth in Section 173 (c) of the CAA, 42 U.S.C. §7503(c).

Overview of California Law

Similar to the federal CAA, the California Health & Safety Code (§§39000 *et seq.*) requires the promulgation of California Ambient Air Quality Standards (CAAQS) for certain pollutants. The California Air Resources Board (CARB) has published CAAQS for the six criteria pollutants regulated under the federal CAA, and for three other pollutants (sulfates, hydrogen sulfide and vinyl sulfide). As with the federal CAA, an area that does not meet the CAAQS for a particular pollutant is designated as a state nonattainment area for that pollutant and the local air district must develop a plan to attain the relevant CAAQS. In general, the California standards are more protective than the corresponding federal standards.

CARB has published in its regulations the state law designations for attainment with the CAAQS. See 17 Cal. Code Regs. §§ 60200 et seq. The Basin, the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB) have all been designated in their entirety as nonattainment areas for the CAAQS for ozone and PM10. See id. §§ 60201, 60205. The Basin also has been designated as a state nonattainment area for PM2.5. See id. § 60210. In addition, CARB adopted new regulations that designated the Basin as a state nonattainment area for nitrogen dioxide and the Los Angeles County portion of the Basin as a state nonattainment area for lead. See CARB Resolution 10-17 (March 25, 2010).

California law requires local air districts in nonattainment areas to implement a stationary source control program designed to achieve no net increase (NNI) in emissions of certain state nonattainment air pollutants from new or modified stationary sources exceeding specified emissions thresholds. As under the CAA, the applicable thresholds depend on the degree of nonattainment in the area in question.

Description of SCAQMD's NSR Permitting Program Per Regulation XIII – New Source Review

The SCAQMD's NSR program, which is codified in Regulation XIII, is designed to meet the requirements of federal and state law[3]. Each of the existing rules in Regulation XIII that collectively comprise the SCAQMD's NSR program is summarized in the following bulleted items:

- **Rule 1301 – General** (adopted October 5, 1979, last amended December 7, 1995): Rule 1301 describes the purpose and applicability of Regulation XIII. As stated in Rule 1301, the purpose of the SCAQMD's NSR program is to ensure that the operation of new, modified or relocated facilities does not interfere with progress in attaining the NAAQSs and the CAAQS, and that future economic growth within the district is not unnecessarily restricted. Rule 1301 (a). A specific goal of the program "is to achieve no net increases from new or modified permitted sources of nonattainment air contaminants or their precursors." *Id*. The program applies to the installation of a new source, or the modification of an existing source, that may cause

[3] Separate NSR requirements for RECLAIM pollutants (NOx and SOx) at RECLAIM facilities are included in Rule 2005. RECLAIM (Regional Clean Air Incentives Market) is a cap and trade program consisting of the largest stationary sources of these pollutants, and Regulation XIII does not apply to these pollutants at RECLAIM sources.

emissions of any federal or state nonattainment air contaminant, any constituent identified by the USEPA as an ozone depleting compound, or ammonia. Rule 1301 (b)(1).

- **Rule 1302 – Definitions** (adopted October 5, 1979, last amended December 6, 2002): Rule 1302 provides definitions for 42 terms and phrases used throughout Regulation XIII.

- **Rule 1303 – Requirements** (adopted October 5, 1979, last amended December 6, 2002): Rule 1303 presents the pre-construction review requirements that make up the core of SCAQMD's NSR program.
  - The requirements include Best Available Control Technology (BACT) for new or modified sources that may cause an increase in emissions of any federal or state nonattainment air contaminant, any ozone depleting compound, or ammonia. Rule 1303 (a). Under the SCAQMD regulations, BACT means the most stringent emissions limitation which: 1) has been achieved in practice for the category or class of source at issue; 2) is contained in any SIP approved by the USEPA for such category or class; or, 3) is based on any other emissions limitation or technique that has been found by the SCAQMD to be technologically feasible and cost-effective. Rule 1302 (h). For "major polluting facilities[4]," the BACT requirements must be at least as stringent as the federal LAER requirements under the CAA. Rule 1303 (a)(2). With respect to other facilities, when updating BACT requirements to make them more stringent, the SCAQMD must consider economic and technological feasibility for the class or category of sources at issue. *Id.*
  - Rule 1303 (b)(1) also requires modeling to show that the new or modified source will not cause a violation, or make significantly worse an existing violation, of any NAAQS or CAAQS at any receptor location in the district.
  - Rule 1303 (b)(2) further requires that, unless there is an exemption under Rule 1304 (see below), emissions increases from the new or modified permitted source must be offset by one of two methods.
    - First, under Rule 1309 (see below), for projects that meet specified eligibility requirements, the applicant can use Emissions Reductions Credits (ERCs), which are created when an operator reduces emissions from a permitted facility. Once ERCs are created, operators may bank ERCs for their own subsequent use or for sale to other permit applicants.
    - Second, under Rule 1309.1 (see below), the SCAQMD may allocate credits from its "Priority Reserve" to offset emissions from "essential

[4] Under the SCAQMD's regulations, a "major polluting facility" is: 1) any facility in the Basin that has the potential to emit 10 tons per year or more of volatile organic compounds (VOCs) or NO_x, or 100 tons of per year of oxides of sulfur (SO_x); 70 tons per year or more of PM10; or 50 tons per year or more of CO; 2) any facility in the Riverside County portion of the SSAB that has the potential to emit 25 tons per year or more of VOCs or NO_x; 70 tons per year or more of PM10; or 100 tons per year or more of CO or SO_x; or, 3) any facility in the Riverside County portion of the MDAB under the SCAQMD's jurisdiction that has the potential to emit 100 tons per year or more of any of these compounds. See Rule 1302 (s).

public services" and other specified "priority sources." As described more fully below, the Priority Reserve is part of an internal "bank" or internal accounts of offsets that the SCAQMD accumulates primarily from "orphan" reductions and shutdowns which occur when an operator reduces emissions from a permitted facility but does not convert the emissions reduction into ERCs. This bank of offsets is referred to in the SCAQMD regulations, and this document, as the SCAQMD's "internal offset accounts."

- Rule 1303 (b)(2)(A) specifies the required offset ratio in terms of the amount of emissions reductions that is needed to compensate for the increase in emissions from the permitted source. For facilities (such as EGFs) located in the Basin, the required offset ratios are 1.0-to-1.0 for allocations from the Priority Reserve[5] and 1.2-to-1.0 for the use of ERCs. For facilities not in the Basin, the required offset ratios are 1.0-to-1.0 for allocations from the Priority Reserve; 1.2-to-1.0 for ERCs for emissions of VOCs, NO_x, SO_x, and PM10; and 1.0-to-1.0 for ERCs for emissions of CO. (Note: the district has achieved the California Ambient Air Quality standards for CO and has been designated as in attainment for the federal standards, so CO emissions are no longer required to be offset.)
- Rule 1303 also includes additional permitting requirements for "major polluting facilities" (as defined above) and "major modifications"[6] at an existing major polluting facility. These requirements include an analysis of alternatives (this requirement may be satisfied through CEQA compliance), a demonstration by the applicant that its facilities in California comply with applicable air quality requirements, and modeling of plume visibility for certain sources of PM10 or NO_x located near specified areas.

- **Rule 1304 - Exemptions** (adopted October 5, 1979, last amended June 14, 1996): Rule 1304 establishes exemptions from the offset requirements in Rule 1303 for the following categories of projects:
  - Replacement of a functionally identical source.
  - Replacement of electric utility steam boilers with specified types of equipment, such as combined cycle gas turbines, intercooled, chemically-recuperated gas turbines, other advanced gas turbines, solar, geothermal, or wind energy or other equipment, as long as the new equipment has a maximum electric power rating

5 Although the offset ratio for credits allocated from the SCAQMD's Priority Reserve account is 1.0-to-1.0, this ratio is for accounting purposes of limiting the use of the Priority Reserve to the level authorized by Rule 1309.1 only and is not the offset ratio used for demonstrating equivalency with federal offset requirements. If the facility accessing the Priority Reserve is a major source then the actual ratio of credits allocated from the SCAQMD's federal offset accounts would be 1.2-to-1.0 for extreme nonattainment air contaminants and their precursors to comply with federal offset requirements.

6 Under the SCAQMD's regulations, a "major modification" is a modification of a major polluting facility that will cause an increase of the facility's potential to emit according to the following criteria: a) for facilities in the Basin, one pound per day of more of VOCs or NO_x; b) for facilities under the SCAQMD's jurisdiction that are not in the Basin, 25 tons per year or more of VOCs or NO_x; or, c) for all facilities under the SCAQMD's jurisdiction, 40 tons per year or more of SO_x, 15 tons per year or more of PM10, or 50 tons per year or more of CO. Rule 1302 (r).

that does not allow basinwide electricity generating capacity on a per-utility basis to increase. PR 1304.1 affects the EGFs obtaining offsets pursuant to this exemption.

- Portable abrasive blasting equipment complying with all state laws.
- Emergency standby equipment for nonutility electric power generation or any other emergency equipment as approved by the SCAQMD, provided the source does not operate more than 200 hours per year.
- Air pollution control strategies (i.e., source modifications) for the sole purpose of reducing emissions.
- Emergency operations performed under the jurisdiction of an authorized health officer, fire protection officer, or other authorized public agency officer. Rule 1304 requires that a specific time limit be imposed for each emergency operation.
- Portable equipment that is not located for more than 12 consecutive months at any one facility in the district. This exemption does not apply to portable internal combustion engines.
- Portable internal combustion engines that are not located for more than 12 consecutive months at any one facility in the district. To qualify for this exemption, the emissions from the engine may not cause an exceedance of an ambient air quality standard and may not exceed specified limits for VOCs, NOx, SOx, PM10 or CO.
- Intra-facility portable equipment meeting specified criteria where emissions from the equipment do not exceed specified emissions thresholds for any of the constituents listed in the bulleted item above.
- Relocation of existing equipment, under the same operator or ownership, and provided that the potential to emit any air contaminant will not be greater at the new location than at the previous location when the source is operated at the same conditions as if current BACT were applied.
- Concurrent facility modifications, which are modifications to a facility after the submittal of an application for a permit to construct, but before the start of operation. The modifications must result in a net emissions decrease and other conditions must also be satisfied.
- Resource recovery and energy conservation projects.
- Regulatory compliance actions (i.e., modifications to comply with federal, state or SCAQMD pollution control requirements), provided there is no increase in the maximum rating of the equipment.
- Regulatory compliance for essential public services.
- Replacement of ozone depleting compounds (ODC), provided the replacement complies with the SCAQMD's "ODC Replacement Guidelines" and meets other specified criteria.
- Methyl bromide fumigation.

- New and modified facilities with only minimal potential to emit (less than four tons per year of VOCs, NOx, SOx, or PM10 and less than 29 tons per year of CO).
- Although SCAQMD Rule 1304 exempts certain types of projects from offset requirements, if they are federal major sources their emission increases are still subject to federal offset requirements pursuant to the CAA's emission requirements. Additionally, specific essential public services and other high priority sources may obtain offsets from the SCAQMD's Priority Reserve pursuant to SCAQMD Rule 1309.1. The NSR Tracking System accounts for offsets provided from the SCAQMD's internal accounts to offset emissions increases from these types of sources.

- **Rule 1306 – Emissions Calculations** (adopted October 5, 1979, last amended December 6, 2002): Rule 1306 codifies the methodology for quantifying emissions increases and emissions reductions for Regulation XIII purposes (e.g., determining applicability of BACT, quantifying the amount of emission offsets required or the amount of ERCs to be banked), but is not applicable to the SCAQMD's internal accounts.
- **Rule 1309 – Emission Reduction Credits and Short Term Credits** (adopted September 10, 1982, last amended December 6, 2002; currently proposed for amendment on July 5, 2013): Rule 1309 sets forth the requirements for eligibility, registration, use and transfer of ERCs for use as offsets under Rule 1303 (b)(2), but is not applicable to the SCAQMD's internal accounts. Among other topics, the rule addresses the validation of past emissions decreases for use as ERCs; the application for an ERC for a new emissions reduction; interpollutant offsets; and inter-basin and inter-district offsets.
- **Rule 1309.1 – Priority Reserve** (adopted June 28, 1990, last amended May 3, 2002[7]): Rule 1309.1 establishes the Priority Reserve, which is part of the SCAQMD's internal accounts of emission offsets. The SCAQMD accumulates offsets in the Priority Reserve primarily from orphan shutdowns and reductions. The SCAQMD then allocates these offsets to meet offset requirements when issuing permits for "essential public services," which are defined to include publicly owned or operated sewage treatment plants, prisons, police and firefighting facilities, schools, hospitals, landfill gas control or processing facilities, water delivery facilities, and public transit facilities. The SCAQMD also allocates offsets from the Priority Reserve when issuing permits for other specified priority sources, such as innovative technologies that result in lower emissions rates and experimental research activities designed to advance the state of the art. The rule requires that, before an eligible facility may use offsets from the Priority Reserve for a particular pollutant, the facility must first use any ERCs that it holds for that pollutant.
- **Rule 1310 – Analysis and Reporting** (adopted October 5, 1979, last amended December 7, 1995): Rule 1310 addresses the Executive Officer's application

[7] Subsequent amendments to Rule 1309.1 in 2006 were replaced by the 2007 amendments, which were invalidated as a result of litigation.

completeness determinations, annual reports to the Governing Board regarding the effectiveness of Regulation XIII and public notice requirements for banking ERCs above specified threshold amounts.

- **Rule 1313 – Permits to Operate** (adopted October 5, 1979, last amended December 7, 1995): Rule 1313 exempts permit renewal, change of operator, or change in Rule 219 – Equipment Not Requiring a Written Permit Pursuant to Regulation II, from the SCAQMD's NSR program, specifies that an application for a permit to operate a source that was constructed without a prior permit to construct is considered an application for a permit to construct for purposes of the SCAQMD's NSR program, establishes a 90-day deadline for facility operators to provide emissions offsets requested by the Executive Officer for a permit to operate, provides a window of up to 90 days for a replacement source to operate concurrently with the source it is replacing, specifies the inclusion of NSR permit conditions on permits, and specifies that relaxing or removing a condition limiting mass emissions from a permit is subject to NSR if that condition limited the source's obligations under NSR.
- **Rule 1315 – Federal New Source Review Tracking System** (Adopted September 8, 2006, Re-Adopted August 3, 2007, Repealed January 8, 2010, and Re-adopted February 4, 2011): Rule 1315 codifies SCAQMD procedures for establishing equivalency under federal New Source Review requirements. Equivalency means that the SCAQMD provides sufficient offsets from its internal offset accounts to cover the emission increases from new or modified sources that are exempt from offsets under SCAQMD rules or that obtain credits from the Priority Reserve, but are subject to offset requirements under federal law. Rule 1315 ensures that exempt sources under Rule 1304 and essential public services and other projects that qualify for Priority Reserve offsets under Rule 1309.1 are fully offset to the extent required by federal law, using valid emission reductions from the SCAQMD's internal offset accounts. Rule 1315 also specifies what types of emissions reductions are eligible to be deposited into the SCAQMD's internal offset accounts, including newly-tracked reductions. "Newly tracked" emissions reductions are reductions that had not been historically tracked until the adoption of a prior version of Rule 1315 in 2006.
- **Rule 1316 – Federal Major Modifications** (Adopted December 2, 2005): Rule 1316 establishes that if a permit applicant demonstrates that a proposed modification to an existing stationary source would not constitute a Federal Major Modification (as defined in the USEPA's regulations in 40 CFR §51.165) the proposed modification is exempt from the analysis of alternatives otherwise required by Rule 1303. Rule 1316 also allows applicants for major polluting facilities to apply for a plantwide applicability limit (PAL), which is a cap on facility-wide emissions of a particular pollutant that allows the operator to make modifications to the facility without triggering the alternatives requirement of Rule 1303, as long as the requirements for PALs are met and the cap is not exceeded.
- **Rule 1325 – Federal PM2.5 New Source Review Program** (Adopted June 3, 2011): Rule 1325 applies to new and modified major sources that trigger the NSR threshold for PM2.5. A major source is defined as having a potential to emit 100 tons per year of PM2.5. Rule 1325 mirrors federal requirements for PM2.5. Rule thresholds, major

modification levels, emission offsets, and other requirements in Rule 1325 are taken directly from U.S. EPA requirements.

PROJECT DESCRIPTION

The proposed project consists of adopting PR 1304.1. The major components of PR 1304.1 are briefly summarized in the following subsections. A complete copy of PR 1304.1 can be found in Appendix A.

The purpose of PR 1304.1 – Electrical Generating Facility Fee for Use of Offset Exemption, is to require any EGF that elects to use a specific offset exemption (Rule 1304 (a)(2)) to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Offsets in SCAQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304 (a)(2). The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 AQMP.

The proposed rule affects all EGF's that elect to use the offset exemptions described in Rule 1304 (a)(2), but not those facilities that meet their emissions obligations through privately held/procured emission reduction credits (ERCs).

The following is a summary of the key proposed concepts of PR 1304.1. A copy of the proposed rule can be found in Appendix A.

- EGFs encumbering/obtaining offsets from the SCAQMD Offset Accounts shall either pay an Offset Fee (F_i), for each pollutant (i), (specifically PM10, NOx, SOx and/or VOC) as applicable to the project/unit(s) on a single, up-front or annual basis for applicable offsets.
- The total EGF fee will be based on the total quantity of offsets utilized from the SCAQMD internal offset accounts for each of the pollutants in pounds per day multiplied by the Fee Rate, for each pollutant, in dollars per pound per day on an annual or single, up-front payment for the use of the offsets for the duration of the project. There are also separate fee structures for less than 100 megawatts and greater than 100 megawatts of generation at a facility.
- The annual or a single, up-front payment for each pollutant is proposed to be derived based on the historical transaction values of ERCs in the open market. Pollutant single fee rates for each of the four potential pollutant offsets (NOx, PM10, VOC and SOx) needed were computed using historical pricing data over a variety of time ranges. For each pollutant and time frame, various statistics were used to determine the most appropriate pricing for an offset unit in dollars per pound per day ($/lb/day). Because of the limited volume of ERCs traded with respect to some pollutants, staff is proposing to utilize sales weighted average cost figures corresponding to the most recent consecutive two years of complete trades in deriving annualized offset fee rates for each pollutant. The annual option would have the payment adjusted annually by the consumer price index (CPI).

- EGF owners/operators electing the annual fee option would be required to pay the annual fee for the first year upfront prior to issuance of the permit to construct the new replacement unit(s), and then annually each year thereafter during any part of which the new replacement unit(s) remain in operation, and for as long as the new replacement unit(s), project and/or EGF are operated. EGF owners/operators electing the single, up-front payment option shall pay the entire fee prior to the issuance of the permit to construct.
- The full amount of any payments made in satisfaction of the requirements of the rule shall be refunded if a written request by the facility owner/operator is received prior to the commencement of operation. Such a request for refund shall automatically trigger cancellation of the Permit to Construct and/or Operate.

Fees collected will be invested in air pollution improvement projects that further the goals of the 2012 AQMP and reduce emissions of pollutants for which the fee is charged or their precursors or pollutants to which they contribute.

PROJECT OBJECTIVES

CEQA Guidelines §15124(b) requires the project description to include a statement of objectives sought by the proposed project, including the underlying purpose of the proposed project. Compatibility with project objectives is one criterion for selecting a range of reasonable project alternatives and provides a standard against which to measure project alternatives. The project objectives identified in the following bullet points have been developed: 1) in compliance with CEQA Guidelines §15124 (b); and, 2) to be consistent with policy objectives of the SCAQMD's New Source Review program. The project objectives are as follows:

- Recoup the fair market value of offsets provided to eligible EGFs from SCAQMD's internal offset bank pursuant to offset exemption Rule 1304 (a)(2);
- Facilitate the continued development of a reliable electric grid within the SCAQMD's jurisdiction while discouraging electric generation not necessary to serve native load or reliability needs.
- Reduce the depletion rate of offsets from SCAQMD's internal offset bank to ensure the continued availability of offsets for essential public services; and,
- Maximize the availability of funds for investment in air pollution reduction projects that further the goals outlined in the 2012 AQMP.

CHAPTER 3

EXISTING SETTING

Existing Setting

Air Quality

Energy

EXISTING SETTING

CEQA Guidelines §15360 (Public Resources Code §21060.5) defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance." According to CEQA Guidelines §15125, a CEQA document will normally include a description of the physical environment in the vicinity of the project, as it exists at the time the NOP is published from both a local and regional perspective. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant. The description of the environmental setting shall be no longer than is necessary to provide an understanding of the significant effects of the proposed project and its alternatives. Since this Draft EA covers the SCAQMD's entire jurisdiction, the existing setting for each category of impact is described on a regional level.

Currently, pursuant to Rule 1304 (a)(2) the replacement of an Electrical Utility Steam Boiler (EUSB) at an EGF is exempt from the modeling and offset requirements of Rule 1303 (b)(2). The exemption is specifically limited to EUSBs that utilize combined cycle gas turbines, intercooled, chemically-recuperated gas turbines, other advanced gas turbines, solar, geothermal, or wind energy or other equipment to the extent that such equipment will allow compliance with Rule 1135 - Emissions of Oxides of Nitrogen from Electric Power Generating Systems or Regulation XX – Regional Clean Air Incentives Market (RECLAIM).

In order to demonstrate compliance with the federal New Source Review (NSR) program, which does not provide for an exemption from offsets as contained in Rule 1304 (a)(2) for EUSB replacement projects, the SCAQMD provides offsets from its internal offset accounts, as described in Rule 1315.

No fee is being charged currently for the provision of offsets from the internal offset accounts. Staff is proposing to assess a fee for up to the full amount of offsets encumbered/obtained and debited from the internal offset accounts. The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 AQMP.

Table 3-1 describes new EGFs that have been permitted over the past years that utilized ERCs or offsets from the SCAQMD internal bank. Table 3-2 describes existing repower projects that have been permitted since 2000 that utilized ERCs or offsets from the SCAQMD internal bank.

TABLE 3-1
EGFs Permitted (since 2000) Using ERCs or SCAQMD Internal Bank

Facility	Location	Megawatts	Start-Up Date	Offsets
Canyon Power Plant	Anaheim	204	2011	ERCs
Riverside DWP	Riverside	242	2001-2009	ERCs
PurEnergy (two projects)*	Colton	84	2001	SCAQMD Bank
SCE (four projects)*	Miraloma, Ontario, Norwalk, Stanton	188	2007	SCAQMD Bank
CPV Sentinel**	Desert Hot Springs	824	2013	SCAQMD Bank
El Colton*	Colton	48	2003	SCAQMD Bank
Inland Empire Energy Center	Menifee	810	2008	SCAQMD Bank
Magnolia Power	Burbank	328	2005	SCAQMD Bank
THUMS*	Long Beach	45	2005	SCAQMD Bank
Wildflower Energy	North Palm Springs	135	2001	SCAQMD Bank
Walnut Creek Energy++	City of Industry	500	2012	SCAQMD Bank
Total		**3,408**		

***** Less than 4 tons per year
****** AB 1318 Tracking System
++ Utility Boiler Replacement (R1304(a)(2))

TABLE 3-2
Existing Repowers / Addition (since 2000) Using ERCs or SCAQMD Internal Bank

Facility	Location	Megawatts Added	Megawatts Removed	Offsets
Edison Mountain View	San Bernardino	1,056	0	ERCs
AES Huntington Beach	Huntington Beach	450	0	ERCs
NRG Long Beach	Long Beach	260	577	ERCs
Bicent Malburg	Vernon	143	0	SCAQMD Bank
Burbank DWP	Burbank	46	48	SCAQMD Bank
LADWP Harbor	Wilmington	237	0	SCAQMD Bank
Glendale DWP**	Glendale	50	53	SCAQMD Bank
Pasadena DWP**	Pasadena	95	90	SCAQMD Bank
LADWP Haynes**	Long Beach	1,206	1,188	SCAQMD Bank
LADWP Valley+	Sun Valley	627	546	SCAQMD Bank
NRG El Segundo+	El Segundo	572	685	SCAQMD Bank
LADWP Scattergood	El Segundo	818		SCAQMD Bank
Total		**5,560**	**3,187**	

** Functionally Identical Replacement
+ Utility Boiler Replacement (R1304(a)(2))

The following section summarizes the existing setting for air quality (including GHG emissions) and energy, which are the only environmental topic areas identified in the NOP/IS (see Appendix B) that may be adversely affected by the proposed project. The Final Program EIR for the 2012 AQMP also contains comprehensive information on existing and projected environmental settings for the topics of air quality and energy. Copies of the referenced document are available from the SCAQMD's Public Information Center by calling (909) 396-2039.

AIR QUALITY

This section provides an overview of air quality in the district whose region could be affected by the proposed project. A more detailed discussion of current and projected future air quality in the district, with and without additional control measures can be found in the Final Program EIR for the 2012 AQMP (Chapter 3).

It is the responsibility of the SCAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, CO, NO2, PM10, PM2.5 SO2 and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are more stringent than the federal standards, and in the case of PM10 and SO2, far more stringent. California has also established standards for sulfates, visibility reducing particles, hydrogen sulfide, and vinyl chloride. The state and national ambient air quality standards for each of these pollutants and their effects on health are summarized in Table 3-3. The SCAQMD monitors levels of various criteria pollutants at 34 monitoring stations. The 2011 air quality data from SCAQMD's monitoring stations are presented in Table 3-4.

TABLE 3-3
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard[a]	Federal Primary Standard[b]	Most Relevant Effects
Ozone (0_3)	1-hour	0.09 ppm (180 μg/m^3)	No Federal Standard	(a) Short-term exposures: 1) Pulmonary function decrements and localized lung edema in humans and animals; and, 2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; (c) Vegetation damage; and, (d) Property damage.
	8-hour	0.070 ppm (137 μg/m^3)	0.075 ppm (147 μg/m^3)	

TABLE 3-3 (Continued)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard (a)	Federal Primary Standard (b)	Most Relevant Effects
Suspended Particulate Matter (PM10)	24-hour	50 μg/m^3	150 μg/m^3	(a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; and (b) Excess seasonal declines in pulmonary function, especially in children.
	Annual Arithmetic Mean	20 μg/m^3	No Federal Standard	
Suspended Particulate Matter (PM2.5)	24-hour	No State Standard	35 μg/m^3	(a) Increased hospital admissions and emergency room visits for heart and lung disease; (b) Increased respiratory symptoms and disease; and (c) Decreased lung functions and premature death.
	Annual Arithmetic Mean	12 μg/m^3	15.0 μg/m^3	
Carbon Monoxide (CO)	1-Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	(a) Aggravation of angina pectoris and other aspects of coronary heart disease; (b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; (c) Impairment of central nervous system functions; and, (d) Possible increased risk to fetuses.
	8-Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO_2)	1-Hour	0.18 ppm (339 μg/m^3)	0.100 ppm (188 μg/m^3)	(a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; (b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; and, (c) Contribution to atmospheric discoloration.
	Annual Arithmetic Mean	0.030 ppm (57 μg/m^3)	0.053 ppm (100 μg/m^3)	
Sulfur Dioxide (SO_2)	1-Hour	0.25 ppm (655 μg/m^3)	75 ppb (196 μg/m^3)–	Broncho-constriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma.
	24-Hour	0.04 ppm (105 μg/m^3)		

TABLE 3-3 (Concluded)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard (a)	Federal Primary Standard (b)	Most Relevant Effects
Sulfates	24-Hour	25 µg/m^3	No Federal Standard	(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; and, (f) Property damage
Hydrogen Sulfide (H_2S)	1-Hour	0.03 ppm (42 µg/m^3)	No Federal Standard	Odor annoyance.
Lead (Pb)	30-Day Average	1.5 µg/m^3	No Federal Standard	(a) Increased body burden; and (b) Impairment of blood formation and nerve conduction.
	Calendar Quarter	No State Standard	1.5 µg/m^3	
	Rolling 3-Month Average	No State Standard	0.15 µg/m^3	
Visibility Reducing Particles	8-Hour	Extinction coefficient of 0.23 per kilometer - visibility of ten miles or more due to particles when relative humidity is less than 70 percent.	No Federal Standard	The Statewide standard is intended to limit the frequency and severity of visibility impairment due to regional haze. This is a visibility based standard not a health based standard. Nephelometry and AISI Tape Sampler; instrumental measurement on days when relative humidity is less than 70 percent.
Vinyl Chloride	24-Hour	0.01 ppm (26 µg/m^3)	No Federal Standard	Highly toxic and a known carcinogen that causes a rare cancer of the liver.

(a) The California ambient air quality standards for O_3, CO, SO_2 (1-hour and 24-hour), NO_2, PM_{10}, and PM_{25} are values not to be exceeded. All other California standards shown are values not to be equaled or exceeded.

(b) The national ambient air quality standards, other than O3 and those based on annual averages, are not to be exceeded more than once a year. The O3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standards is equal to or less than one.

KEY:	ppb = parts per billion parts of air, by volume	ppm = parts per million parts of air, by volume	µg/m^3 = micrograms per cubic meter	mg/ m^3 = milligrams per cubic meter

TABLE 3-4
2011 Air Quality Data – South Coast Air Quality Management District

CARBON MONOXIDE (CO)[a]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. ppm, 1-hour	Max. Conc. ppm, 8-hour
LOS ANGELES COUNTY				
1	Central Los Angeles	365	2.8	2.4
2	Northwest Coastal Los Angeles County	360	3.0	1.3
3	Southwest Coastal Los Angeles County	364	2.3	1.8
4	South Coastal Los Angeles County 1	365	3.2	2.6
4	South Coastal Los Angeles County 2	--	--	--
4	South Coastal LA County 3	354	3.7	3.3
6	West San Fernando Valley	355	3.2	2.8
7	East San Fernando Valley	365	2.8	2.4
8	West San Gabriel Valley	365	2.9	2.2
9	East San Gabriel Valley 1	365	2.4	1.4
9	East San Gabriel Valley 2	362	1.4	1.1
10	Pomona/Walnut Valley	364	2.1	1.6
11	South San Gabriel Valley	365	2.7	2.4
12	South Central Los Angeles County	364	6.0	4.7
13	Santa Clarita Valley	363	1.2	0.8
ORANGE COUNTY				
16	North Orange County	365	3.4	2.1
17	Central Orange County	365	2.7	2.1
18	North Coastal Orange County	344	2.9	2.2
19	Saddleback Valley	365	1.4	0.8
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	365	2.0	1.4
23	Metropolitan Riverside County 2	365	2.7	1.5
23	Mira Loma	361	2.2	1.4
24	Perris Valley	--	--	--
25	Lake Elsinore	365	1.7	0.7
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	350	1.1	0.6
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	365	1.8	1.3
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	365	1.6	1.1
34	Central San Bernardino Valley 2	365	1.9	1.7
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
DISTRICT MAXIMUM			6	4.7
SOUTH COAST AIR BASIN			6	4.7

KEY:

ppm = parts per million -- = Pollutant not monitored ** Salton Sea Air Basin

[a] The federal 8-hour standard (8-hour average CO > 9 ppm) and state 8-hour standard (8-hour average CO > 9.0 ppm) were not exceeded. The federal and state 1-hour standards (35 ppm and 20 ppm) were not exceeded either.

TABLE 3-4 (Continued)
2011 Air Quality Data – South Coast Air Quality Management District

OZONE (O_3)										
						No. Days Standard Exceeded				
						Health Advisory	Federal		State	
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hr	Max. Conc. in ppm 8-hr	4th High Conc. ppm 8-hr	≥ 0.15 ppm 1-hr	Old > 0.12 ppm 1-hr	Current >0.075 ppm 8-hr	Current > 0.09 ppm 1-hr	Current > 0.070 ppm 8-hr
LOS ANGELES COUNTY										
1	Central Los Angeles	365	0.087	0.080	0.065	0.060	0	0	0	0
2	Northwest Coastal Los Angeles County	360	0.098	0.095	0.071	0.061	0	0	2	0
3	Southwest Coastal Los Angeles County	360	0.078	0.076	0.067	0.062	0	0	0	0
4	South Coastal Los Angeles County 1	363	0.073	0.072	0.061	0.059	0	0	0	0
4	South Coastal Los Angeles County 2	--	--	--	--	--	--	--	--	--
4	South Coastal LA County 3	360	0.074	0.066	0.063	0.057	0	0	0	0
6	West San Fernando Valley	365	0.130	0.129	0.103	0.091	3	26	17	35
7	East San Fernando Valley	364	0.120	0.111	0.084	0.081	0	6	8	10
8	West San Gabriel Valley	365	0.107	0.101	0.084	0.077	0	5	5	13
9	East San Gabriel Valley 1	365	0.111	0.108	0.092	0.082	0	12	13	19
9	East San Gabriel Valley 2	362	0.134	0.133	0.111	0.095	4	30	35	40
10	Pomona/Walnut Valley	364	0.119	0.111	0.096	0.086	0	16	15	24
11	South San Gabriel Valley	362	0.096	0.086	0.074	0.061	0	0	1	1
12	South Central Los Angeles County	362	0.082	0.080	0.065	0.061	0	0	0	0
13	Santa Clarita Valley	363	0.144	0.129	0.122	0.101	3	31	31	52
ORANGE COUNTY										
16	North Orange County	365	0.095	0.091	0.074	0.069	0	0	1	3
17	Central Orange County	365	0.088	0.085	0.072	0.064	0	0	0	1
18	North Coastal Orange County	360	0.093	0.084	0.077	0.063	0	1	0	2
19	Saddleback Valley	365	0.094	0.092	0.083	0.074	0	2	0	5
RIVERSIDE COUNTY										
22	Norco/Corona	-	-	-	-	-	-	-	-	-
23	Metropolitan Riverside County 1	--	--	--	--	--	--	--	--	--
23	Metropolitan Riverside County 2	365	0.128	0.127	0.115	0.106	4	67	52	92
23	Mira Loma	--	--	--	--	--	--	--	--	--
24	Perris Valley	362	0.126	0.117	0.104	0.096	1	36	32	63
25	Lake Elsinore	364	0.125	0.125	0.112	0.094	2	54	44	77
29	Banning Airport	365	0.133	0.123	0.106	0.092	1	28	19	45
30	Coachella Valley 1**	355	0.105	0.094	0.085	0.073	0	14	1	27
30	Coachella Valley 2**	362	0.127	0.127	0.111	0.100	3	41	35	59
SAN BERNARDINO COUNTY										
32	Northwest San Bernardino Valley	365	0.145	0.134	0.122	0.098	5	36	36	45
33	Southwest San Bernardino Valley	--	--	--	--	--	--	--	--	--
34	Central San Bernardino Valley 1	365	0.144	0.140	0.124	0.105	5	39	39	53
34	Central San Bernardino Valley 2	365	0.135	0.125	0.121	0.101	2	39	40	66
35	East San Bernardino Valley	364	0.151	0.135	0.133	0.113	7	80	64	96
37	Central San Bernardino Mountains	360	0.160	0.135	0.136	0.106	8	84	58	103
38	East San Bernardino Mountains	--	--	--	--	--	--	--	--	--
	DISTRICT MAXIMUM		0.160	0.140	0.136	0.113	8	84	64	103
	SOUTH COAST AIR BASIN		0.160	0.140	0.136	0.113	16	106	90	125

KEY:

ppm = parts per million -- = Pollutant not monitored ** Salton Sea Air Basin

TABLE 3-4 (Continued)
2011 Air Quality Data – South Coast Air Quality Management District

NITROGEN DIOXIDE (NO_2)[b]					
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	1-hour Max. Conc. ppb, 1,	1-hour 98th Percentile Conc. ppb,	Annual Average AAM Conc. ppb
LOS ANGELES COUNTY					
1	Central Los Angeles	365	109.6	67.0	23.1
2	Northwest Coastal Los Angeles County	360	81.3	58.2	13.9
3	Southwest Coastal Los Angeles County	365	97.6	64.8	13.4
4	South Coastal Los Angeles County 1	365	106.4	67.6	17.7
4	South Coastal Los Angeles County 2	--	--	--	--
4	South Coastal LA County 3	359	90.0	74.0	21.2
6	West San Fernando Valley	359	56.1	53.8	14.9
7	East San Fernando Valley	365	67.8	56.2	22.1
8	West San Gabriel Valley	359	87.3	72.8	20.3
9	East San Gabriel Valley 1	356	79.5	65.1	19.0
9	East San Gabriel Valley 2	361	77.6	53.9	12.9
10	Pomona/Walnut Valley	364	87.3	66.7	24.6
11	South San Gabriel Valley	362	90.6	72.0	23.7
12	South Central Los Angeles County	361	75.4	65.3	18.6
13	Santa Clarita Valley	360	60.1	46.8	13.3
ORANGE COUNTY					
16	North Orange County	365	69.8	60.7	17.7
17	Central Orange County	365	73.8	60.8	16.8
18	North Coastal Orange County	350	60.5	52.8	10.0
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metropolitan Riverside County 1	359	63.3	56.5	16.6
23	Metropolitan Riverside County 2	364	57.1	50.4	16.9
23	Mira Loma	364	58.8	51.8	15.3
24	Perris Valley	--	--	--	--
25	Lake Elsinore	365	50.3	41.3	9.6
29	Banning Airport	--	--	--	--
30	Coachella Valley 1**	350	60.7	50.2	9.5
30	Coachella Valley 2**	350	44.7	39.4	8.0
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	353	68.5	60.1	19.6
33	Southwest San Bernardino Valley	--	--	--	--
34	Central San Bernardino Valley 1	365	76.4	64.6	21.1
34	Central San Bernardino Valley 2	365	61.9	52.9	16.9
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM			109.6	72.8	24.6
SOUTH COAST AIR BASIN			109.6	72.8	24.6

KEY:

ppb = parts per billion AAM = Annual Arithmetic Mean -- = Pollutant not monitored ** Salton Sea Air Basin

[b] The NO2 federal 1-hour standard is 100 ppb and the annual standard is annual arithmetic mean NO_2 > 0.0534 ppm. The state 1-hour and annual standards are 0.18 ppm and 0.030 ppm.

TABLE 3-4 (Continued)
2011Air Quality Data – South Coast Air Quality Management District

SULFUR DIOXIDE (SO_2)[c]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Conc. ppb, 1-hour	Maximum Conc. ppb, 24-hour
LOS ANGELES COUNTY				
1	Central Los Angeles	331	19.8	5.6
2	Northwest Coastal Los Angeles County	--	--	
3	Southwest Coastal Los Angeles County	365	11.5	3.3
4	South Coastal Los Angeles County 1	365	14.8	4.3
4	South Coastal Los Angeles County 2	--	--	
4	South Coastal LA County 3	350	43.3	11.6
6	West San Fernando Valley	--	--	
7	East San Fernando Valley	363	9.0	
8	West San Gabriel Valley	--	--	
9	East San Gabriel Valley 1	--	--	
9	East San Gabriel Valley 2	--	--	
10	Pomona/Walnut Valley	--	--	
11	South San Gabriel Valley	--	--	
12	South Central Los Angeles County	--	--	
13	Santa Clarita Valley	--	--	
ORANGE COUNTY				
16	North Orange County			
17	Central Orange County	--	--	
18	North Coastal Orange County	--	--	2.0
19	Saddleback Valley	357	7.7	
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	
23	Metropolitan Riverside County 1	365	51.3	11.4
23	Metropolitan Riverside County 2	--	--	
23	Mira Loma	--	--	
24	Perris Valley	--	--	
25	Lake Elsinore	--	--	
29	Banning Airport	--	--	
30	Coachella Valley 1**	--	--	
30	Coachella Valley 2**	--	--	
32	Northwest San Bernardino Valley	--	--	
33	Southwest San Bernardino Valley	--	--	
34	Central San Bernardino Valley 1	365	12.3	4.0
34	Central San Bernardino Valley 2	--	--	
35	East San Bernardino Valley	--	--	
37	Central San Bernardino Mountains	--	--	
38	East San Bernardino Mountains	--	--	
DISTRICT MAXIMUM			51.3	11.6
SOUTH COAST AIR BASIN			51.3	11.6

KEY:

ppb = parts per billion -- = Pollutant not monitored ** Salton Sea Air Basin

[c] The federal SO2 1-hour standard is 75 ppb (0.075 ppm). The state standards are 1-hour average SO_2 > 0.25 ppm and 24-hour average SO_2 > 0.04 ppm.

TABLE 3-4 (Continued)
2011 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM10[d]						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. $\mu g/m^3$, 24-hour	No. (%) Samples Exceeding Standard		Annual Average AAM Conc. $\mu g/m^3$
				Federal > 150 $\mu g/m^3$, 24-hour	State > 50 $\mu g/m^3$, 24-hour	
LOS ANGELES COUNTY						
1	Central Los Angeles					
2	Northwest Coastal Los Angeles County	59	53	0	1(2%)	29.0
3	Southwest Coastal Los Angeles County	--	--	--	--	--
4	South Coastal Los Angeles County 1	59	41	0	0	21.6
4	South Coastal Los Angeles County 2	60	43	0	0	24.2
4	South Coastal LA County 3	60	50	0	0	28.7
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	--	--	--	--	--
8	West San Fernando Valley	55	61	0	2(4%)	29.0
9	East San Gabriel Valley 1					
9	East San Gabriel Valley 2	61	65	0	9(15%)	32.9
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central Los Angeles County	--	--	--	--	--
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	60	53	0	2(3%)	24.8
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	61	48	0	0	19.2
RIVERSIDE COUNTY0						
22	Norco/Corona	59	60	0	2(3%)	27.8
23	Metropolitan Riverside County 1	112	82	0	14(13%)	33.7
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	79	0	25(42%)	41.1
24	Perris Valley	60	65	0	3(5%)	29.3
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	59	51	0	1(2%)	19.5
30	Coachella Valley 2**	61 [f)]	42 [f)]	0 [f)]	0 [f)]	18.6 [f)]
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	60	70	0	3(5%)	31.3
34	Central San Bernardino Valley 1	60	84	0	4(7%)	31.8
34	Central San Bernardino Valley 2	58	56	0	3(5%)	31.5
35	East San Bernardino Valley	58	71	0	2(3%)	25.5
37	Central San Bernardino Mountains	59	43	0	0	19.2
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM	106	0	25	41.1	106
	SOUTH COAST AIR BASIN	84 [g)]	0	35	41.1	84 [f)]

KEY: $\mu g/m^3$ = micrograms per cubic meter AAM = Annual Arithmetic Mean -- = Pollutant not monitored ** Salton Sea Air Basin

[d] Federal Reference Method (FRM) PM10 samples were collected every 6 days at all sites except for Station Numbers 4144 and 4157, where samples were collected every three days. PM10 statistics listed above are for the FRM data only. Federal Equivalent Method (FEM) PM10 continuous monitoring instruments were operated at some of the above locations. Max 24-hour average PM10 concentrations at sites with FEM monitoring in 2011 was 152 $\mu g/m^3$, at Mira Loma

[e] Federal annual PM10 standard (AAM > 50 $\mu g/m^3$) was revoked in 2006. State standard is annual average (AAM) > 20 $\mu g/m^3$

[f] High PM10 and PM2.5 data samples occurred due to special events (i.e., high wind, firework activities, etc.) were excluded in accordance with the EPA Exceptional Event Regulation. Excluded PM10 data: 396 and 265 $\mu g/m^3$ on July 3 and August 28, at Palm Springs (FEM); 344 and 375 $\mu g/m^3$ on July 3 and August 28, at Indio (FEM); 323 $\mu g/m^3$ on August 28, at Indio (FRM). Excluded PM2.5 data: 94.6 $\mu g/m^3$ on July 5, at Azusa.

TABLE 3-4 (Continued)
2011 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM2.5 [g]						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. $\mu g/m^3$, 24-hour	98^{th} Percentile Conc. in $\mu g/m^3$ 24-hr	No. (%) Samples Exceeding Federal Std > 35 $\mu g/m^3$, 24-hour	Annual Average AAM Conc. $\mu g/m^3$
LOS ANGELES COUNTY						
1	Central Los Angeles	59	53	0	1(2%)	29.0
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	59	41	0	0	21.6
4	South Coastal Los Angeles County 1	60	43	0	0	24.2
4	South Coastal Los Angeles County 2	60	50	0	0	28.7
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	55	61	0	2(4%)	29.0
8	West San Gabriel Valley					
9	East San Gabriel Valley 1	61	65	0	9(15%)	32.9
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central Los Angeles County	--	--	--	--	--
13	Santa Clarita Valley	58	45	0	0	20.7
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	60	53	0	2(3%)	24.8
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	61	48	0	0	19.2
RIVERSIDE COUNTY						
22	Norco/Corona	59	60	0	2(3%)	27.8
23	Metropolitan Riverside County 1	112	82	0	14(13%)	33.7
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	79	0	25(42%)	41.1
24	Perris Valley	60	65	0	3(5%)	29.3
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	59	51	0	1(2%)	19.5
30	Coachella Valley 2**	61 [f)]	42 [f)]	0 [f)]	0 [f)]	18.6 [f)]
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	60	70	0	3(5%)	31.3
34	Central San Bernardino Valley 1	60	84	0	4(7%)	31.8
34	Central San Bernardino Valley 2	58	56	0	3(5%)	31.5
35	East San Bernardino Valley	58	71	0	2(3%)	25.5
37	Central San Bernardino Mountains	59	43	0	0	19.2
38	East San Bernardino Mountains	--	--	--	--	--
DISTRICT MAXIMUM		106	0	25	41.1	106
SOUTH COAST AIR BASIN		84 [f)]	0	35	41.1	84 [f)]

KEY:

$\mu g/m^3$ = micrograms per cubic meter of air AAM = Annual Arithmetic Mean -- = Pollutant not monitored ** Salton Sea Air Basin

[g] PM2.5 samples were collected every three days at all sites except for station numbers 069, 072, 077, 087, 3176, 4144 and 4165, where samples were taken daily, and station number 5818 where samples were taken every six days. Federal annual PM2.5 standard is annual average (AAM) > 15.0 $\mu g/m^3$. State standard is annual average (AAM) > 12.0 $\mu g/m^3$.

TABLE 3-4 (Continued)
2011 Air Quality Data – South Coast Air Quality Management District

TOTAL SUSPENDED PARTICULATES TSP				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. µg/m^3, 24-hour	Annual Average AAM Conc. µg/m^3
LOS ANGELES COUNTY				
1	Central Los Angeles	60	84	53.7
2	Northwest Coastal Los Angeles County	59	155	49.3
3	Southwest Coastal Los Angeles County	55	69	36.1
4	South Coastal Los Angeles County 1	61	91	44.0
4	South Coastal Los Angeles County 2	56	81	43.9
4	South Coastal LA County 3	--	--	--
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	--	--	--
8	West San Gabriel Valley	59	74	44.1
9	East San Gabriel Valley 1	57	154	72.5
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	59	140	64.4
12	South Central Los Angeles County	57	112	52.8
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	-	-	-
17	Central Orange County	-	-	-
18	North Coastal Orange County	-	-	-
19	Saddleback Valley	-	-	-
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	60	107	62.7
23	Metropolitan Riverside County 2	59	83	43.8
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	58	94	47.2
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	54	131	64.7
34	Central San Bernardino Valley 2	61	97	51.4
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
DISTRICT MAXIMUM			155	72.5
SOUTH COAST AIR BASIN			155	72.5

KEY:

µg/m^3 = micrograms per cubic meter of air   AAM = Annual Arithmetic Mean   -- = Pollutant not monitored   ** Salton Sea Air Basin

TABLE 3-4 (Concluded)
2011 Air Quality Data – South Coast Air Quality Management District

		LEAD[h]			SULFATES (SOx)[i]	
Source Receptor Area No.	Location of Air Monitoring Station	Max. Monthly Average Conc. [m)] $\mu g/m^3$	Max. 3-Months Rolling Averages, μg/m3	Max. Quarterly Average Conc. [m)] $\mu g/m^3$	Max. Conc. $\mu g/m^3$, 24-hour	No. (%) Samples Exceeding State Standard $\geq 25\ \mu g/m^3$, 24-hour
	LOS ANGELES COUNTY					
1	Central Los Angeles	0.012	0.011	0.011	58	8.0
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	0.008	0.006	0.005	58	5.9
4	South Coastal Los Angeles County 1	0.010	0.007	0.007	59	6.1
4	South Coastal Los Angeles County 2	0.013	0.010	0.010	60	5.9
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	--	--	--	54	7.4
8	West San Gabriel Valley	--	--	--	--	--
9	East San Gabriel Valley 1	--	--	--	60	6.6
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	0.011	0.010	0.010	--	--
12	South Central Los Angeles County	0.014	0.011	0.010	--	--
13	Santa Clarita Valley	--	--	--	58	6.1
	ORANGE COUNTY					
16	North Orange County	--		--	--	--
17	Central Orange County	--		--	60	6.5
18	North Coastal Orange County	--		--	--	--
19	Saddleback Valley	--		--	61	4.8
	RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	56	5.1
23	Metropolitan Riverside County 1	0.007	0.007	0.007	178	5.3
23	Metropolitan Riverside County 2	0.007	0.006	0.006	--	--
23	Mira Loma	--	--	--	58	5.4
24	Perris Valley	--	--	--	58	4.4
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	--	--	--	59	4.4
30	Coachella Valley 2**	--	--	--	61	4.4
	SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	0.009	0.008	0.007	--	--
33	Southwest San Bernardino Valley	--	--	--	116	5.5
34	Central San Bernardino Valley 1	--	--	--	59	6.0
34	Central San Bernardino Valley 2	0.008	0.007	0.007	59	5.5
35	East San Bernardino Valley	--	--	--	57	4.9
37	Central San Bernardino Mountains	--	--	--	57	4.0
38	East San Bernardino Mountains	--	--	--	--	--
DISTRICT MAXIMUM		0.014	0.011	0.011		8.0
SOUTH COAST AIR BASIN		0.014	0.011	0.011		8.0

KEY:

$\mu g/m^3$ = micrograms per cubic meter of air   -- = Pollutant not monitored   ** Salton Sea Air Basin

[h] Federal lead standard is 3-months rolling average > 0.15 $\mu g/m^3$; and state standard is monthly average $\geq$ 1.5 $\mu g/m^3$. No regular monitoring location exceeded lead standards. Standards exceeded at special monitoring sites immediately downwind of stationary lead sources. Maximum monthly and 3-month rolling averages at special monitoring sites were 0.52 μg/m3 and 0.45 μg/m3, respectively..

[i] State sulfate standard is 24-hour $\geq$ 25 $\mu g/m^3$. There is no federal standard for sulfate.

Carbon Monoxide

CO is a colorless, odorless, relatively inert gas. It is a trace constituent in the unpolluted troposphere, and is produced by both natural processes and human activities. In remote areas far from human habitation, carbon monoxide occurs in the atmosphere at an average background concentration of 0.04 ppm, primarily as a result of natural processes such as forest fires and the oxidation of methane. Global atmospheric mixing of CO from urban and industrial sources creates higher background concentrations (up to 0.20 ppm) near urban areas. The major source of CO in urban areas is incomplete combustion of carbon-containing fuels, mainly gasoline. According to the 2007 AQMP, in 2002, the inventory baseline year, approximately 98 percent of the CO emitted into the Basin's atmosphere was from mobile sources. Consequently, CO concentrations are generally highest in the vicinity of major concentrations of vehicular traffic.

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the Basin exhibit large spatial and temporal variations due to variations in the rate at which CO is emitted and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable portion of the day.

Individuals with a deficient blood supply to the heart are the most susceptible to the adverse effects of CO exposure. The effects observed include earlier onset of chest pain with exercise, and electrocardiograph changes indicative of worsening oxygen supply to the heart.

Inhaled CO has no direct toxic effect on the lungs, but exerts its effect on tissues by interfering with oxygen transport by competing with oxygen to combine with hemoglobin present in the blood to form carboxyhemoglobin (COHb). Hence, conditions with an increased demand for oxygen supply can be adversely affected by exposure to CO. Individuals most at risk include patients with diseases involving heart and blood vessels, fetuses (unborn babies), and patients with chronic hypoxemia (oxygen deficiency) as seen in high altitudes.

Reductions in birth weight and impaired neurobehavioral development have been observed in animals chronically exposed to CO resulting in COHb levels similar to those observed in smokers. Recent studies have found increased risks for adverse birth outcomes with exposure to elevated CO levels. These include pre-term births and heart abnormalities.

Carbon monoxide concentrations were measured at 26 locations in the Basin and neighboring Salton Sea Air Basin (SSAB) areas in 2011. Carbon monoxide concentrations did not exceed the standards in 2010. The highest one-hour average carbon monoxide concentration recorded (6.0 ppm in the South Central Los Angeles County area) was 17 percent of the federal one-hour carbon monoxide standard of 35 ppm. The highest eight-hour average carbon monoxide concentration recorded (4.7 ppm in the South Central Los Angeles County area) was 52 percent of the federal eight-hour carbon monoxide standard of 9.0 ppm. The state one-hour standard is also 9.0 ppm. The highest eight-hour average carbon monoxide concentration is 23.5 percent of the state eight-hour carbon monoxide standard of 20 ppm.

The 2003 AQMP revisions to the SCAQMD's CO Plan served two purposes: it replaced the 1997 attainment demonstration that lapsed at the end of 2000; and it provided the basis for a CO maintenance plan in the future. In 2004, the SCAQMD formally requested the U.S. EPA to re-designate the Basin from non-attainment to attainment with the CO National Ambient Air Quality Standards. On February 24, 2007, U.S. EPA published in the Federal Register its proposed decision to re-designate the Basin from non-attainment to attainment for CO. The comment period on the re-designation proposal closed on March 16, 2007 with no comments received by the U.S. EPA. On May 11, 2007, U.S. EPA published in the Federal Register its final decision to approve the SCAQMD's request for re-designation from non-attainment to attainment for CO, effective June 11, 2007.

Ozone

Ozone (O3), a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone transport is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (e.g., from 0.03 ppm to 0.05 ppm).

While ozone is beneficial in the stratosphere because it filters out skin-cancer-causing ultraviolet radiation, it is a highly reactive oxidant. It is this reactivity which accounts for its damaging effects on materials, plants, and human health at the earth's surface.

The propensity of ozone for reacting with organic materials causes it to be damaging to living cells and ambient ozone concentrations in the Basin are frequently sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, and reduces the respiratory system's ability to remove inhaled particles and fight infection.

Individuals exercising outdoors, children and people with preexisting lung disease, such as asthma and chronic pulmonary lung disease, are considered to be the most susceptible subgroups for ozone effects. Short-term exposures (lasting for a few hours) to ozone at levels typically observed in southern California can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes. In recent years, a correlation between elevated ambient ozone levels and increases in daily hospital admission rates, as well as mortality, has also been reported. An increased risk for asthma has been found in children who participate in multiple sports and live in high ozone communities. Elevated ozone levels are also associated with increased school absences.

Ozone exposure under exercising conditions is known to increase the severity of the abovementioned observed responses. Animal studies suggest that exposures to a combination of pollutants which include ozone may be more toxic than exposure to ozone alone. Although lung volume and resistance changes observed after a single exposure diminish with repeated exposures, biochemical and cellular changes appear to persist, which can lead to subsequent lung structural changes.

In 2011, the SCAQMD regularly monitored ozone concentrations at 31 locations in the Basin and SSAB. Maximum ozone concentrations for all areas monitored were below the stage 1 episode level (0.20 ppm) and below the health advisory level (0.15 ppm). Maximum ozone concentrations in the SSAB areas monitored by the SCAQMD were lower than in the Basin and were below the health advisory level.

In 2011, the maximum ozone concentrations in the Basin continued to exceed federal standards by wide margins. Maximum one-hour and eight-hour average ozone concentrations were 0.160 ppm and 0.136 ppm, respectively (the maximum one-hour and eight-hour concentrations were recorded in the Central San Bernardino Mountains area). The federal one-hour ozone standard was revoked and replaced by the eight-hour average ozone standard effective June 15, 2005. U.S. EPA has revised the federal eight-hour ozone standard from 0.84 ppm to 0.075 ppm, effective May 27, 2008. The maximum eight-hour concentration was 181 percent of the new federal standard. The maximum one-hour concentration was 178 percent of the one-hour state ozone standard of 0.09 ppm. The maximum eight-hour concentration was 194 percent of the eight-hour state ozone standard of 0.070 ppm.

The objective of the 2012 AQMP was to attain and maintain ambient air quality standards. Based upon the modeling analysis described in the Program Environmental Impact Report for the 2007 AQMP, implementation of all control measures contained in the 2012 AQMP is anticipated to bring the district into compliance with the federal eight-hour ozone standard by 2023 and the state eight-hour ozone standard beyond 2023.

Nitrogen Dioxide

NO2 is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N2) and oxygen (O2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO2. NO2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO2, are referred to collectively as NOx. In the presence of sunlight, NO2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO3) which reacts further to form nitrates, components of PM2.5 and PM10.

Population-based studies suggest that an increase in acute respiratory illness, including infections and respiratory symptoms in children (not infants), is associated with long-term exposures to NO2 at levels found in homes with gas stoves, which are higher than ambient levels found in southern California. Increase in resistance to air flow and airway contraction is observed after short-term exposure to NO2 in healthy subjects. Larger decreases in lung functions are observed in individuals with asthma and/or chronic obstructive pulmonary disease (e.g., chronic bronchitis, emphysema) than in healthy individuals, indicating a greater susceptibility of these sub-groups. More recent studies have found associations between NO2 exposures and cardiopulmonary mortality, decreased lung function, respiratory symptoms and emergency room asthma visits.

In animals, exposure to levels of NO_2 considerably higher than ambient concentrations results in increased susceptibility to infections, possibly due to the observed changes in cells involved in maintaining immune functions. The severity of lung tissue damage associated with high levels of ozone exposure increases when animals are exposed to a combination of ozone and NO_2.

In 2011, nitrogen dioxide concentrations were monitored at 26 locations. No area of the Basin or SSAB exceeded the federal or state standards for nitrogen dioxide. The Basin has not exceeded the federal standard for nitrogen dioxide (0.0534 ppm) since 1991, when the Los Angeles County portion of the Basin recorded the last exceedance of the standard in any county within the United States.

In 2011, the maximum annual average concentration was 24.6 ppb recorded in the Pomona/Walnut Valley area. Effective March 20, 2008, CARB revised the nitrogen dioxide one-hour standard from 0.25 ppm to 0.18 ppm and established a new annual standard of 0.30 ppm. In addition, U.S. EPA has established a new federal one-hour NO_2 standard of 100 ppb (98th percentile concentration), effective April 7, 2010. The highest one-hour average concentration recorded (109.6 ppb in Central Los Angeles) was 61 percent of the state one-hour standard and the highest annual average concentration recorded was 8.2 percent of the state annual average standard. However, the 98^{th} percentile concentration in 2011 did not exceed the new Federal 1-hour NO_2 standard. NO_x emission reductions continue to be necessary because it is a precursor to both ozone and PM ($PM_{2.5}$ and PM_{10}) concentrations.

Sulfur Dioxide

SO_2 is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H_2SO_4), which contributes to acid precipitation, and sulfates, which are components of PM_{10} and $PM_{2.5}$. Most of the SO_2 emitted into the atmosphere is produced by burning sulfur-containing fuels.

Exposure of a few minutes to low levels of SO_2 can result in airway constriction in some asthmatics. All asthmatics are sensitive to the effects of SO_2. In asthmatics, increase in resistance to air flow, as well as reduction in breathing capacity leading to severe breathing difficulties, is observed after acute higher exposure to SO_2. In contrast, healthy individuals do not exhibit similar acute responses even after exposure to higher concentrations of SO_2.

Animal studies suggest that despite SO_2 being a respiratory irritant, it does not cause substantial lung injury at ambient concentrations. However, very high levels of exposure can cause lung edema (fluid accumulation), lung tissue damage, and sloughing off of cells lining the respiratory tract.

Some population-based studies indicate that the mortality and morbidity effects associated with fine particles show a similar association with ambient SO_2 levels. In these studies, efforts to separate the effects of SO_2 from those of fine particles have not been successful. It is not clear whether the two pollutants act synergistically or one pollutant alone is the predominant factor.

No exceedances of federal or state standards for sulfur dioxide occurred in 2011 at any of the seven district locations monitored. The maximum one-hour sulfur dioxide concentration was 51.3 ppb, as recorded in the Metropolitan Riverside County 1 area. The maximum 24-hour sulfur dioxide concentration was 11.6 ppb, as recorded in South Coastal Los Angeles County 3 area. The U.S. EPA revised the federal sulfur dioxide standard by establishing a new one-hour standard of 0.075 ppm and revoking the existing annual arithmetic mean (0.03 ppm) and the 24-hour average (0.14 ppm), effective August 2, 2010. The state standards are 0.25 ppm for the one-hour average and 0.04 ppm for the 24-hour average. Though sulfur dioxide concentrations remain well below the standards, sulfur dioxide is a precursor to sulfate, which is a component of fine particulate matter, PM10, and PM2.5. Historical measurements showed concentrations to be well below standards and monitoring has been discontinued.

Particulate Matter (PM10 and PM2.5)
Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM10 and PM2.5.

A consistent correlation between elevated ambient fine particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the United States and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer.

Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. In addition to children, the elderly, and people with pre-existing respiratory and/or cardiovascular disease appear to be more susceptible to the effects of PM10 and PM2.5.

The SCAQMD monitored PM10 concentrations at 21 locations in 2011. The federal 24-hour PM10 standard (150 µg/m3) was not exceeded at any of the locations monitored in 2010. The federal annual PM10 standard has been revoked, effective 2006. The maximum 24-hour PM10 concentration of 106 µg/m3 was recorded in the Coachella Valley No. 2 area and was 71 percent of the federal standard and 212 percent of the much more stringent state 24-hour PM10 standard (50 µg/m3). The state 24-hour PM10 standard was exceeded at 14 of the 21 monitoring stations. The maximum annual average PM10 concentration of 41.3 µg/m3 was recorded in Mira Loma. The maximum annual average PM10 concentration in Mira Loma was 207 percent of the state standard of 20 µg/m3. The USEPA published approval of SCAQMD's PM10 attainment plan on June 26, 2013, with an implementation date of July 26, 2013.

In 2011, PM2.5 concentrations were monitored at 20 locations throughout the district. U.S. EPA revised the federal 24-hour PM2.5 standard from 65 µg/m3 to 35 µg/m3, effective December 17, 2006. In 2011, the maximum PM2.5 concentrations in the Basin exceeded the new federal 24-hour PM2.5 standard in all but five locations. The maximum 24-hour PM2.5 concentration of 65 µg/m3 was recorded in the Central San Bernardino Valley 2 area, which represents 186 percent of the federal standard of 35 µg/m3. The maximum annual average concentration of 15.3 µg/m3 was recorded in Mira Loma, which represents 102 percent of the federal standard of 15 µg/m3 and 128 percent of the state standard of 12 µg/m3. At a 98th percentile concentration of PM2.5 in µg/m3, only one location exceeded the federal standard of 35 µg/m3.

Similar to PM10 concentrations, PM2.5 concentrations were higher in the inland valley areas of San Bernardino and Metropolitan Riverside counties. However, PM2.5 concentrations were also high in Central Los Angeles County and East San Gabriel Valley. The high PM2.5 concentrations in Los Angeles County are mainly due to the secondary formation of smaller particulates resulting from mobile and stationary source activities. In contrast to PM10, PM2.5 concentrations were low in the Coachella Valley area of SSAB. PM10 concentrations are normally higher in the desert areas due to windblown and fugitive dust emissions.

Lead

Lead in the atmosphere is present as a mixture of a number of lead compounds. Leaded gasoline and lead smelters have been the main sources of lead emitted into the air. Due to the phasing out of leaded gasoline, there was a dramatic reduction in atmospheric lead in the Basin over the past three decades.

Fetuses, infants, and children are more sensitive than others to the adverse effects of lead exposure. Exposure to low levels of lead can adversely affect the development and function of the central nervous system, leading to learning disorders, distractibility, inability to follow simple commands, and lower intelligence quotient. In adults, increased lead levels are associated with increased blood pressure.

Lead poisoning can cause anemia, lethargy, seizures, and death. It appears that there are no direct effects of lead on the respiratory system. Lead can be stored in the bone from early-age environmental exposure, and elevated blood lead levels can occur due to breakdown of bone tissue during pregnancy, hyperthyroidism (increased secretion of hormones from the thyroid gland), and osteoporosis (breakdown of bone tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.

The old federal and current state standards for lead were not exceeded in any area of the district in 2011. There have been no violations of these standards at the SCAQMD's regular air monitoring stations since 1982, as a result of removal of lead from gasoline. The maximum quarterly average lead concentration (0.011 µg/m3 at monitoring stations in Central Los Angeles) was 0.7 percent of the old federal quarterly average lead standard (1.5 µg/m3). The maximum monthly average lead concentration (0.014 µg/m3 in South Central Los Angeles County), measured at special monitoring sites immediately adjacent to stationary sources of lead was 0.9 percent of the state monthly average lead standard. No lead data were obtained at SSAB and Orange County stations in 2011. Because historical lead data showed concentrations in SSAB and Orange County areas to be well below the standard, measurements have been discontinued.

On November 12, 2008, U.S. EPA published new national ambient air quality standards for lead, which became effective January 12, 2010. The existing national lead standard, 1.5 µg/m3, was reduced to 0.15 µg/m3, averaged over a rolling three-month period. The new federal standard was not exceeded at any source/receptor location in 2011. Nevertheless, U.S. EPA designated the Los Angeles County portion of the Basin as non-attainment for the new lead standard, effective December 31, 2010, primarily based on emissions from two battery recycling facilities. In response to the new federal lead standard, the SCAQMD adopted Rule 1420.1 – Emissions Standard for Lead from Large Lead-Acid Battery Recycling Facilities, in November 2010, to ensure that lead emissions do not exceed the new federal standard. Further, in May 2012, the SCAQMD adopted the 2012 Lead SIP to address the revision to the federal lead standard, which outlines the strategy and pollution control activities to demonstrate attainment of the federal lead standard before December 31, 2015. The two affected facilities have been in compliance with the new lead standard since January 2012.

Sulfates

Sulfates (SOx) are chemical compounds which contain the sulfate ion and are part of the mixture of solid materials which make up PM10. Most of the sulfates in the atmosphere are produced by oxidation of SO2. Oxidation of sulfur dioxide yields sulfur trioxide (SO3) which reacts with water to form sulfuric acid, which contributes to acid deposition. The reaction of sulfuric acid with basic substances such as ammonia yields sulfates, a component of PM10 and PM2.5.

Most of the health effects associated with fine particles and SO2 at ambient levels are also associated with SOx. Thus, both mortality and morbidity effects have been observed with an increase in ambient SOx concentrations. However, efforts to separate the effects of SOx from the effects of other pollutants have generally not been successful.

Clinical studies of asthmatics exposed to sulfuric acid suggest that adolescent asthmatics are possibly a subgroup susceptible to acid aerosol exposure. Animal studies suggest that acidic particles such as sulfuric acid aerosol and ammonium bisulfate are more toxic than non-acidic particles like ammonium sulfate. Whether the effects are attributable to acidity or to particles remains unresolved.

In 2011, the state 24-hour sulfate standard (25 µg/m3) was not exceeded in any of the monitoring locations in the district. There are no federal sulfate standards.

Vinyl Chloride

Vinyl chloride is a colorless, flammable gas at ambient temperature and pressure. It is also highly toxic and is classified by the American Conference of Governmental Industrial Hygienists (ACGIH) as A1 (confirmed carcinogen in humans) and by the International Agency for Research on Cancer (IARC) as 1 (known to be a human carcinogen)(Air Gas, 2010). At room temperature, vinyl chloride is a gas with a sickly sweet odor that is easily condensed. However, it is stored as a liquid. Due to the hazardous nature of vinyl chloride to human health there are no end products that use vinyl chloride in its monomer form. Vinyl chloride is a chemical intermediate, not a final product. It is an important industrial chemical chiefly used to produce polymer polyvinyl chloride (PVC). The process involves vinyl chloride liquid fed to polymerization reactors where it is converted from a monomer to a polymer PVC. The final product of the polymerization process is PVC in either a flake or pellet form. Billions of pounds of PVC are sold on the global market each year. From its flake or pellet form, PVC is sold to companies that heat and mold the PVC into end products such as PVC pipe and bottles.

In the past, vinyl chloride emissions have been associated primarily with sources such as landfills. Risks from exposure to vinyl chloride are considered to be a localized impacts rather than regional impacts. Because landfills in the district are subject to SCAQMD 1150.1, which contains stringent requirements for landfill gas collection and control, potential vinyl chloride emissions are below the level of detection. Therefore, the SCAQMD does not monitor for vinyl chloride at its monitoring stations.

Volatile Organic Compounds

It should be noted that there are no state or national ambient air quality standards for VOCs because they are not classified as criteria pollutants. VOCs are regulated, however, because limiting VOC emissions reduces the rate of photochemical reactions that contribute to the formation of ozone. VOCs are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

Visibility

In 2005, annual average visibility at Rubidoux (Riverside), the worst case, was just over 10 miles. With the exception of Lake County, which is designated in attainment, all of the air districts in California are currently designated as unclassified with respect to the CAAQS for visibility reducing particles.

In Class-I wilderness areas, which typically have visual range measured in tens of miles the deciview metric is used to estimate an individual’s perception of visibility. The deciview index works inversely to visual range which is measured in miles or kilometers whereby a lower deciview is optimal. In the South Coast Air Basin, the Class-I areas are typically restricted to higher elevations (greater than 6,000 feet above sea level) or far downwind of the metropolitan emission source areas. Visibility in these areas is typically unrestricted due to regional haze despite being in close proximity to the urban setting. The 2005 baseline deciview mapping of the Basin is presented in Figure 3-1. All of the Class-I wilderness areas reside in areas having average deciview values less than 20 with many portions of those areas having average deciview values less than 10. By contrast, Rubidoux, in the Basin has a deciview value exceeding 30.

Federal Regional Haze Rule

The federal Regional Haze Rule, established by the U.S. EPA pursuant to CAA §169A, establishes the national goal to prevent future and remedy existing impairment of visibility in federal Class I areas (such as federal wilderness areas and national parks). U.S. EPA's visibility regulations (40 CFR 51.300 through 51.309), require states to develop measures necessary to make reasonable progress towards remedying visibility impairment in these federal Class I areas. Section 169A and these regulations also require Best Available Retrofit Technology for certain large stationary sources that were put in place between 1962 and 1977. See Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Federal Register 39104 (July 6, 2005).

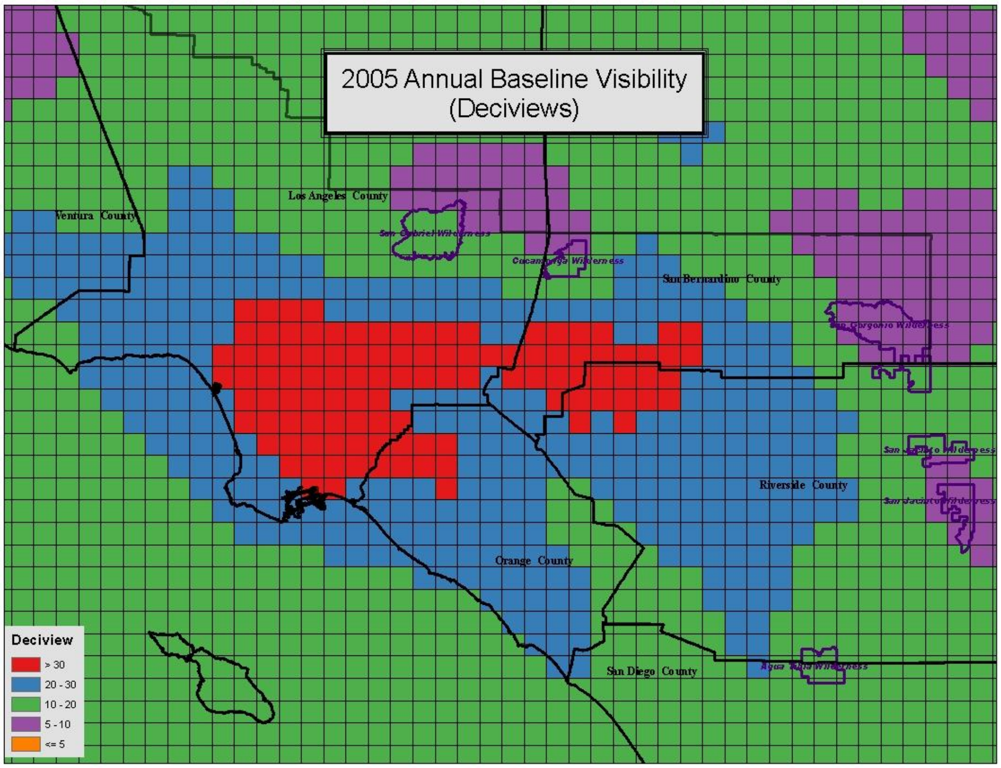


FIGURE 3-1
2005 Annual Baseline Visibility

<u>California Visibility Standard</u>

Since deterioration of visibility is one of the most obvious manifestations of air pollution and plays a major role in the public's perception of air quality, the state of California has adopted a standard for visibility or visual range. Until 1989, the standard was based on visibility estimates made by human observers. The standard was changed to require measurement of visual range using instruments that measure light scattering and absorption by suspended particles.

The visibility standard is based on the distance that atmospheric conditions allow a person to see at a given time and location. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter. Visibility degradation occurs when visibility reducing particles are produced in sufficient amounts such that the extinction coefficient is greater than 0.23 inverse kilometers (to reduce the visual range to less than 10 miles) at relative humidity less than 70 percent, 8-hour average (from 10:00 a.m. to 6:00 p.m.) according to the state standard. Future-year visibility in the Basin is projected empirically using the results derived from a regression analysis of visibility with air quality measurements. The regression data set consisted of aerosol composition data collected during a special monitoring program conducted concurrently with visibility data collection (prevailing visibility observations from airports and visibility measurements from district monitoring stations). A full description of the visibility analysis is given in Appendix V of the 2012 AQMP.

With future year reductions of PM2.5 from implementation of all proposed emission controls for 2015, the annual average visibility would improve from 10 miles (calculated for 2008) to over 20 miles at Rubidoux, for example. Visual range in 2021 at all other Basin sites is expected to equal or exceed the Rubidoux visual range. Visual range is expected to double from the 2008 baseline due to reductions of secondary PM2.5, directly emitted PM2.5 (including diesel soot) and lower nitrogen dioxide concentrations as a result of 2007 AQMP controls.

To meet Federal Regional Haze Rule requirements, CARB adopted the California Regional Haze Plan on January 22, 2009, addressing California's visibility goals through 2018. As stated in Table 3-2 above, California's statewide standard (applicable outside of the Lake Tahoe area) for Visibility Reducing Particles is an extinction coefficient of 0.23 per kilometer over an 8-hour averaging period. This translates to visibility of ten miles or more due to particles when relative humidity is less than 70 percent.

Air Quality Management Plan

Air Quality Management Plans (AQMPs) are developed to demonstrate attainment with the federal and state ambient air quality standards for the various criteria pollutants. The AQMP provides the latest emissions inventory from the variety of polluting sources in the region and a comprehensive control strategy to reduce those emissions to meet the standards. The purpose of the 2012 AQMP was to address the federal eight-hour and one-hour (revoked) ozone and PM2.5 air quality standards, to satisfy the planning requirements of the federal Clean Air Act (CAA), and to develop transportation emission budgets using the latest approved motor vehicle emissions model and planning assumptions. The focus of the AQMP was to demonstrate attainment of the federal 24-hour PM2.5 ambient air quality standard by 2014, while making expeditious progress toward attainment of state PM standards. In addition, to further implement the existing 8-hour ozone plan, the 2012 AQMP includes Section 182 (e)(5) implementation measures designed to assist in future attainment of the 8-hour ozone standard. The proposed control measures in the 2012 AQMP are based on implementing all feasible control measures through the application of available technologies and management practices as well as development and deployment of advanced technologies and control methods. Similar to the approaches taken in previous AQMPs, the SIP commitment includes an adoption and implementation schedule for each control measure. Each agency is also committed to achieving a total emission reduction target with the ability to substitute specified control measures for control measures deemed infeasible, as long as equivalent reductions are met by other means. These measures are also designed to satisfy the federal CAA requirement of reasonably available control technologies [§172 (c)], and the California requirement of Best Available Retrofit Control Technologies (BARCT) [Health and Safety Code §40440 (b)(1)].

The 2012 AQMP control measures consist of three components: 1) the SCAQMD's stationary and mobile source control measures; 2) suggested State mobile source control measures; and 3) Regional Transportation Strategy and control measures provided by Southern California

Association of Governments (SCAG). These measures rely on not only the traditional command-and-control approach, but also public incentive programs, as well as advanced technologies expected to be developed and deployed in the next several years.

The specific stationary and mobile source control measures from the 2012 AQMP are listed below in Tables 3-5 and 3-6, respectively.

TABLE 3-5
Stationary Source Control Measures Categorized by Source Type

NUMBER	TITLE	CM TYPE	ADOPTION	IMPLEMENTATION PERIOD	REDUCTION (TPD)
PM SOURCES					
BCM-01 (*formerly MCS-04B*)	Further Reductions from Residential Wood Burning Devices [PM2.5]	Short-term 24-hr PM2.5	2013	2013-2014	7.1 [a]
BCM-02 *(new)*	Further Reductions from Open Burning [PM2.5]	Short-term 24-hr PM2.5	2013	2013-2014	4.6 [b]
BCM-03 *(formerly BCM-01 & BCM-05 in the 2007 AQMP)*	Emission Reductions from Under-Fired Charbroilers [PM2.5]	Short-term 24-hr PM2.5	Phase I – 2013 (*Tech Assessment*) Phase II - TBD	TBD	1.0 [c]
BCM-04 *(formerly MCS-04B)*	Further Ammonia Reductions from Livestock Waste [NH3]	Short-term 24-hr PM2.5	Phase I – 2013-2014 (*Tech Assessment*) Phase II - TBD	TBD	TBD [d]
COMBUSTION SOURCES					
CMB-01[i]	Further NOx Reductions from RECLAIM [NOx] – *Phase I*	Short-term 24-hr PM2.5	2013	2014	2-3
CMB-01 [j]	Further NOx Reductions from RECLAIM [NOx] – *Phase II*	Section 182 (e)(5) implementation	2015	2020	1-2
CMB-02	NOx Reductions from Biogas Flares [NOx]	Section 182 (e)(5) implementation	2015	Beginning 2017	Pending[e]
CMB-03	Reductions from Commercial Space Heating [NOx]	Section 182 (e)(5) implementation	Phase I – 2014 (*Tech Assessment*) Phase II - 2016	Beginning 2018	0.18 by 2023 0.6 (total)

TABLE 3-5 (Continued)
Stationary Source Control Measures Categorized by Source Type

NUMBER	TITLE	CM TYPE	ADOPTION	IMPLEMENTATION PERIOD	REDUCTION (TPD)
COATINGS AND SOLVENTS					
CTS-01	Further VOC Reductions from Architectural Coatings (R1113) [VOC]	Section 182 (e)(5) implementation	2015 - 2016	2018 - 2020	2-4
CTS-02	Further Emission Reduction from Miscellaneous Coatings, Adhesives, Solvents and Lubricants [VOC]	Section 182 (e)(5) implementation	2013 - 2016	2015 - 2018	1-2
CTS-03	Further VOC Reductions from Mold Release Products [VOC]	Section 182 (e)(5) implementation	2014	2016	0.8 – 2
CTS-04	Further VOC Reductions from Consumer Products [VOC]	Section 182 (e)(5) implementation	2013 - 2015	2018	N/A[f]
PETROLEUM OPERATIONS AND FUGITIVE VOC					
FUG-01	VOC Reductions from Vacuum Trucks [VOC]	Section 182 (e)(5) implementation	2014	2016	1[g]
FUG-02	Emission Reduction from LPG Transfer and Dispensing [VOC] – *Phase II*	Section 182 (e)(5) implementation	2015	2017	1-2
FUG-03	Further Reductions from Fugitive VOC Emissions [VOC]	Section 182 (e)(5) implementation	2015 -2016	2017-2018	1-2
MULTIPLE COMPONENT SOURCES					
MCS-01	Application of All Feasible Measures Assessment [All Pollutants]	Short-term 24-hr PM2.5 and section 182 (e)(5) implementation	Ongoing	Ongoing	TBD [d]
MCS-02	Further Emission Reductions from Green Waste Processing (Chipping and Grinding Operations Not Associated with Composting) [VOC]	Section 182 (e)(5) implementation	2015	2016	1 [g]
MCS-03 (*formerly MCS-06 in the 2007 AQMP*)	Improved Start-up, Shutdown and Turnaround Procedures [All Pollutants]	Section 182 (e)(5) implementation	Phase I – 2012 (*Tech Assessment*) Phase II - TBD	Phase I – 2013 (*Tech Assessment*) Phase II - TBD	TBD [d]

TABLE 3-5 (Concluded)
Stationary Source Control Measures Categorized by Source Type

NUMBER	TITLE	CM TYPE	ADOPTION	IMPLEMENTATION PERIOD	REDUCTION (TPD)
INDIRECT SOURCES					
IND -01 (*formerly MOB-03*)	Backstop Measures for Indirect Sources of Emissions from Ports and Port-Related Sources [NOx, SOx, PM2.5]	Short-term 24-hr PM2.5	2013	12 months after trigger	N/A[f]
INCENTIVE PROGRAMS					
INC-01	Economic Incentive Programs to Adopt Zero and Near-Zero Technologies [NOx]	Section 182 (e)(5) implementation	2014	Within 12 months after funding availability	TBD [h]
INC-02	Expedited Permitting and CEQA Preparation Facilitating the Manufacturing of Zero and Near-Zero Technologies [All Pollutants]	Section 182 (e)(5) implementation	2014-2015	Beginning 2015	N/A[f]
EDUCATIONAL PROGRAMS					
EDU-01 (*formerly MCS-02, MCS-03*)	Further Criteria Pollutant Reductions from Education, Outreach and Incentives [All Pollutants]	Short-term 24-hr PM2.5 and Section 182 (e)(5) implementation	Ongoing	Ongoing	N/A[f]

a. Winter average day reductions based on episodic conditions and 75 percent compliance rate.
b. Reduction based on episodic day conditions.
c. Will submit into SIP once technically feasible and cost effective options are confirmed.
d. TBD are reductions to be determined once the technical assessment is complete, and inventory and control approach are identified.
e. Pending because emission reductions will be provided prior to the Final Draft.
f. N/A are reductions that cannot be quantified due to the nature of the measure (e.g., outreach, incentive programs) or if the measure is designed to ensure reductions that have been assumed to occur will, in fact, occur.
g. Reductions submitted in SIP once emission inventories are included in the SIP.
h. TBD are reductions to be determined once the inventory and control approach are identified.
i. Emission reductions are included in the SIP as a contingency measure.

If Control Measure CMB-01, RECLAIM Phase I, contingency measure emission reductions are not triggered and implemented, Phase II will target a cumulative 3-5 TPD of NOx emission reductions.

TABLE 3-6
Mobile Source Control Measures Categorized by Source Type

§182 (e)(5) PROPOSED IMPLEMENTATION 8-HOUR OZONE MEASURES - ON-ROAD MOBILE SOURCES				
CM Number	**Title**	**Adoption**	**Implementation Period**	**Reduction (tpd)**
ONRD-01	Accelerated Penetration of Partial Zero-Emission and Zero Emission Vehicles [VOC, NOx, PM]	N/A	Ongoing	TBD [a]
ONRD-02	Accelerated Retirement of Older Light-Duty and Medium-Duty Vehicles [VOC, NOx, PM]	N/A	Ongoing	TBD [a]
ONRD-03	Accelerated Penetration of Partial Zero-Emission and Zero Emission Light Heavy-Duty Vehicles [NOx, PM]	N/A	Ongoing	TBD [a]
ONRD-04	Accelerated Retirement of Older Heavy-Duty Vehicles [NOx, PM]	N/A	Ongoing	TBD [a,b]
ONRD-05	Further Emission Reductions from Heavy-Duty Vehicles Serving Near-Dock Railyards [NOx, PM]	2014	2015-2020	0.75 [NOx] 0.025 [PM2.5]
§182 (E)(5) PROPOSED IMPLEMENTATION 8-HOUR OZONE MEASURES – OFF-ROAD MOBILE SOURCES				
OFFRD-01	Extension of the SOON Provision for Construction/Industrial Equipment [NOx]	N/A	Ongoing	7.5
OFFRD-02	Further Emission Reductions from Freight Locomotives [NOx, PM]	Ongoing	2015 -2023	12.7 [NOx] 0.32 [PM2.5]
OFFRD-03	Further Emission Reductions from Passenger Locomotives [NOx, PM]	Ongoing	Beginning 2014	3.0 [NOx] [c] 0.06 [PM2.5] [c]
OFFRD-04	Further Emission Reductions from Ocean-Going Marine Vessels While at Berth [NOx, PM]	N/A	Ongoing	TBD [a]
OFFRD-05	Emission Reductions from Ocean-Going marine Vessels [NOx]	N/A	Ongoing	TBD [a]

TABLE 3-6 (Concluded)
Mobile Source Control Measures Categorized by Source Type

CM Number	Title	Adoption	Implementation Period	Reduction (tpd)
ADV-01	§182 (e) Proposed Implementation Measures f the Deployment of Zero- and Near-Zero Emission On-Road Heavy-Duty Vehicles [NOx]	N/A	2012 and on	TBD [d]
ADV-02	§182 (e) Proposed Implementation Measures for the Deployment of Zero- and Near-Zero Emission Locomotives [NOx]	N/A	2012 and on	TBD [d]
ADV-03	§182 (e) Proposed Implementation Measures for the Deployment of Zero- and Near-Zero Emission Cargo Handling Equipment [NOx]	N/A	2012 and on	TBD [d]
ADV-04	§182 (e) Proposed Implementation Measures for the Deployment of Cleaner Commercial Harborcraft [NOx]	N/A	2012 and on	TBD [d]
ADV-05	§182 (e) Proposed Implementation Measures for the Deployment of Cleaner Ocean-Going Marine Vessels [NOx]	N/A	2012 and on	TBD [d]
ADV-06	§182 (e) Proposed Implementation Measures for the Deployment of Cleaner Off-Road Equipment [NOx]	N/A	2012 and on	TBD [d]
ADV-07	§182 (e) Proposed Implementation Measures for the Deployment of Cleaner Aircraft Engines [NOx]	N/A	2012 and on	TBD [d]

a) Emission reductions will be determined after projects are identified and implemented
b) Reductions achieved locally in Mira Loma region
c) Submitted into the SIP once technically feasible and cost effective options are confirmed
d) Emission reductions will be quantified after the projects are demonstrated.

Non-Criteria Pollutants

Although the SCAQMD's primary mandate is attaining the State and National Ambient Air Quality Standards for criteria pollutants within the district, SCAQMD also has a general responsibility pursuant to Health and Safety Code (HSC) §41700 to control emissions of air contaminants and prevent endangerment to public health. Additionally, state law requires the SCAQMD to implement airborne toxic control measures (ATCM) adopted by CARB, and to implement the Air Toxics "Hot Spots" Act. As a result, the SCAQMD has regulated pollutants other than criteria pollutants such as TACs, greenhouse gases and stratospheric ozone depleting compounds (ODCs). The SCAQMD has developed a number of rules to control non-criteria pollutants from both new and existing sources. These rules originated through state directives, CAA requirements, or the SCAQMD rulemaking process.

In addition to promulgating non-criteria pollutant rules, the SCAQMD has been evaluating AQMP control measures as well as existing rules to determine whether or not they would affect, either positively or negatively, emissions of non-criteria pollutants. For example, rules in which VOC components of coating materials are replaced by a non-photochemically reactive chlorinated substance would reduce the impacts resulting from ozone formation, but could increase emissions of toxic compounds or other substances that may have adverse impacts on human health.

The following subsections summarize the existing setting for the two major categories of non-criteria pollutants: compounds that contribute to TACs global climate change, and stratospheric ozone depletion.

Air Quality – Toxic Air Contaminants

Federal

Under Section 112 of the CAA, U.S. EPA is required to regulate sources that emit one or more of the 187 federally listed hazardous air pollutants (HAPs). HAPs are air toxic pollutants identified in the CAA, which are known or suspected of causing cancer or other serious health effects. The federal HAPs are listed on the U.S. EPA website at http://www.epa.gov/ttn/atw/orig189.html. In order to implement the CAA, approximately 100 National Emission Standards for Hazardous Air Pollutants (NESHAPs) have been promulgated by U.S. EPA for major sources (sources emitting greater than 10 tons per year of a single HAP or greater than 25 tons per year of multiple HAPs). The SCAQMD can either directly implement NESHAPs or adopt rules that contain requirements at least as stringent as the NESHAP requirements. However, since NESHAPs often apply to sources in the district that are controlled, many of the sources that would have been subject to federal requirements already comply or are exempt.

In addition to the major source NESHAPs, U.S. EPA has also controlled HAPs from urban areas by developing Area Source NESHAPs under their Urban Air Toxics Strategy. U.S. EPA defines an area source as a source that emits less than 10 tons annually of any single hazardous air pollutant or less than 25 tons annually of a combination of hazardous air pollutants. The CAA requires the U.S. EPA to identify a list of at least 30 air toxics that pose the greatest potential health threat in urban areas. U.S. EPA is further required to identify and establish a list of area source categories that represent 90 percent of the emissions of the 30 urban air toxics associated with area sources, for which Area Source NESHAPs are to be developed under the CAA. U.S. EPA has identified a total of 70 area source categories with regulations promulgated for more than 30 categories so far.

The federal toxics program recognizes diesel engine exhaust as a health hazard, however, diesel particulate matter itself is not one of their listed toxic air contaminants. Rather, each toxic compound in the speciated list of compounds in exhaust is considered separately. Although there are no specific NESHAP regulations for diesel PM, diesel particulate emission reductions are realized through federal regulations including diesel fuel standards and emission standards for stationary, marine, and locomotive engines; and idling controls for locomotives.

State

The California air toxics program was based on the CAA and the original federal list of hazardous air pollutants. The state program was established in 1983 under the Toxic Air Contaminant Identification and Control Act, Assembly Bill (AB) 1807, Tanner. Under the state program, toxic air contaminants are identified through a two-step process of risk identification and risk management. This two-step process was designed to protect residents from the health effects of toxic substances in the air.

Control of TACs under the TAC Identification and Control Program

California's TAC identification and control program, adopted in 1983 as AB 1807, is a two-step program in which substances are identified as TACs, and ATCMs are adopted to control emissions from specific sources. CARB has adopted a regulation designating all 188 federal hazardous air pollutants (HAPs) as TACs.

ATCMs are developed by CARB and implemented by the SCAQMD and other air districts either directly or through the adoption of regulations of equal or greater stringency. Generally, the ATCMs reduce emissions to achieve exposure levels below a determined health threshold. If no such threshold levels are determined, emissions are reduced to the lowest level achievable through the best available control technology unless it is determined that an alternative level of emission reduction is adequate to protect public health.

Under California law, a federal NESHAP automatically becomes a state ATCM, unless CARB has already adopted an ATCM for the source category. Once a NESHAP becomes an ATCM, CARB and each air pollution control or air quality management district have certain responsibilities related to adoption or implementation and enforcement of the NESHAP/ATCM.

Control of TACs under the Air Toxics "Hot Spots" Act

The Air Toxics Hot Spots Information and Assessment Act of 1987 (AB 2588) establishes a state-wide program to inventory and assess the risks from facilities that emit TACs and to notify the public about significant health risks associated with the emissions. Facilities are phased into the AB 2588 program based on their emissions of criteria pollutants or their occurrence on lists of toxic emitters compiled by the SCAQMD. Phase I consists of facilities that emit over 25 tons per year of any criteria pollutant and facilities present on the SCAQMD's toxics list. Phase I facilities entered the program by reporting their air TAC emissions for calendar year 1989. Phase II consists of facilities that emit between 10 and 25 tons per year of any criteria pollutant, and submitted air toxic inventory reports for calendar year 1990 emissions. Phase III consists of certain designated types of facilities which emit less than 10 tons per year of any criteria pollutant, and submitted inventory reports for calendar year 1991 emissions. Inventory reports are required to be updated every four years under the state law.

Air Toxics Control Measures

As part of its risk management efforts, CARB has passed state ATCMs to address air toxics from mobile and stationary sources. Some key ATCMs for stationary sources include reductions of benzene emissions from service stations, hexavalent chromium emissions from chrome plating, perchloroethylene emissions from dry cleaning, ethylene oxide emissions from sterilizers, and multiple air toxics from the automotive painting and repair industries.

Many of CARB's recent ATCMs are part of the CARB Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles (DRRP), which was adopted in September 2000 (http://www.arb.ca.gov/diesel/documents/rrpapp.htm) with the goal of reducing diesel particulate matter emissions from compression ignition engines and associated health risk by 75 percent by 2010 and 85 percent by 2020. The DRRP includes strategies to reduce emissions from new and existing engines through the use of ultra-low sulfur diesel fuel, add-on controls, and engine replacement. In addition to stationary source engines, the plan addresses diesel PM emissions from mobile sources such as trucks, buses, construction equipment, locomotives, and ships.

<u>*SCAQMD*</u>

SCAQMD has regulated criteria air pollutants using either a technology-based or an emissions limit approach. The technology-based approach defines specific control technologies that may be installed to reduce pollutant emissions. The emission limit approach establishes an emission limit, and allows industry to use any emission control equipment, as long as the emission requirements are met. The regulation of TACs often uses a health risk-based approach, but may also require a regulatory approach similar to criteria pollutants, as explained in the following subsections.

Rules and Regulations

Under the SCAQMD's toxic regulatory program there are 15 source-specific rules that target toxic emission reductions from over 10,000 sources such as metal finishing, spraying operations, dry cleaners, film cleaning, gasoline dispensing, and diesel-fueled stationary engines to name a few. In addition, other rules targeting criteria pollutant emission reductions also may also produce co-benefits of reducing air toxic emissions. For example, Rule 461, which regulates VOC emissions from gasoline dispensing, may also reduce benzene emissions, a component of gasoline, while Rule 1124, which regulates VOC emissions from aerospace component and manufacturing operations, may also reduce air toxic emissions such as perchloroethylene, trichloroethylene, and methylene chloride emissions contained in solvents and coatings used in aerospace operations.

New and modified sources of toxic air contaminants in the district are subject to Rule 1401 - New Source Review of Toxic Air Contaminants. In addition, Rule 212 – Standards for Approving Permits, requires notification of the SCAQMD's intent to grant a permit to construct a significant project, a new or modified permit unit posing an maximum individual cancer risk of one in one million (1×10^{-6}) or greater, or a new or modified facility with criteria pollutant emissions exceeding specified daily maximums. Distribution of notice is required to all addresses within a 1/4-mile radius, or other area deemed appropriate by the SCAQMD. Rule 1401 currently controls emissions of carcinogenic and non-carcinogenic (health effects other than cancer) air contaminants from new, modified and relocated sources by specifying limits on cancer risk and hazard index (explained further in the following discussion), respectively. The rule lists nearly 300 TACs that are evaluated during the SCAQMD's permitting process for new, modified or relocated sources. During the past decade, more than 80 compounds have been added or had risk values amended. The addition of diesel particulate matter from diesel-fueled internal combustion engines as a TAC in March 2008 was the most significant of recent amendments to the rule. Rule 1401.1 sets risk thresholds for new and relocated facilities near schools. The requirements are more stringent than those for other air toxics rules in order to provide additional protection to school children.

Air Toxics Control Plan
In March 2000, the SCAQMD Governing Board approved the Air Toxics Control Plan (ATCP) which was the first comprehensive plan in the nation to guide future toxic rulemaking and programs. The ATCP was developed to lay out the SCAQMD's air toxics control program which built upon existing federal, state, and local toxic control programs as well as co-benefits from implementation of State Implementation Plan (SIP) measures. The concept for the plan was an outgrowth of the Environmental Justice principles and the Environmental Justice Initiatives adopted by the SCAQMD Governing Board in October 1997. Monitoring studies and air toxics regulations that were created from these initiatives emphasized the need for a more systematic approach to reducing toxic air contaminants. The intent of the plan was to reduce exposure to air toxics in an equitable and cost-effective manner that promotes clean, healthful air in the district. The plan proposed control strategies to reduce toxic air contaminants in the district implemented between years 2000 and 2010 through cooperative efforts of the SCAQMD, local governments, CARB and U.S. EPA.

2003 Cumulative Impact Reduction Strategies
The SCAQMD Governing Board approved a cumulative impacts reduction strategy in September 2003. The resulting 25 cumulative impacts strategies were a key element of the 2004 Addendum to the ATCP. The strategies included rules, policies, funding, education, and cooperation with other agencies. Some of the key SCAQMD accomplishments related to the cumulative impacts reduction strategies were:

- Rule 1401.1 which set more stringent health risk requirements for new and relocated facilities near schools
- Rule 1470 which established diesel PM emission limits and other requirements for diesel-fueled engines
- Rule 1469.1 which regulated chrome spraying operations
- Rule 410 which addresses odors from transfer stations and material recovery facilities
- Intergovernmental Review comment letters for CEQA documents
- SCAQMD's land use guidance document
- Additional protection in toxics rules for sensitive receptors, such as more stringent requirements for chrome plating operations and diesel engines located near schools

Addendum to the ATCP
The Addendum to the ATCP (Addendum) was adopted by the SCAQMD Governing Board in 2004 and served as a status report regarding implementation of the various mobile and stationary source strategies in the 2000 ATCP and introduced new measures to further address air toxics.

Clean Communities Plan

On November 5, 2010, the SCAQMD Governing Board approved the 2010 Clean Communities Plan (CCP) whose objective is to reduce the exposure to air toxics and air-related nuisances throughout the district, with emphasis on cumulative impacts through community exposure reduction, community participation, communication and outreach, agency coordination, monitoring and compliance, source-specific programs, and nuisance. The 2010 CCP pilot study was implemented at: (1) the City of San Bernardino; and, (2) Boyle Heights and surrounding areas.

Control of TACs under the Air Toxics "Hot Spots" Act

In October 1992, the SCAQMD Governing Board adopted public notification procedures for Phase I and II facilities. These procedures specify that AB 2588 facilities must provide public notice when exceeding the following risk levels:

- Maximum Individual Cancer Risk: greater than 10 in one million (10×10^{-6})
- Total Hazard Index: greater than 1.0 for TACs except lead, or > 0.5 for lead

Public notice is to be provided by letters mailed to all addresses and all parents of children attending school in the impacted area. In addition, facilities must hold a public meeting and provide copies of the facility risk assessment in all school libraries and a public library in the impacted area.

There are currently about 600 facilities in the SCAQMD's AB2588 program implemented through Rule 1402. Since 1992 when the state Health and Safety Code incorporated a risk reduction requirement in the program, the SCAQMD has reviewed and approved over 300 HRAs, 44 facilities were required to do a public notice, and 21 facilities were subject to risk reduction. Currently, over 96 percent of the facilities in the program have cancer risks below ten in a million and over 98 percent have acute and chronic hazard indices of less than one.

Multiple Air Toxics Exposure Studies (MATES)

In 1986, SCAQMD conducted the first MATES Study to determine the Basin-wide risks associated with major airborne carcinogens. Toxic air contaminants are determined by the U.S. EPA, and by the Cal/EPA, including the Office of Environmental Health Hazard Assessment and the ARB. For purposes of MATES, the California carcinogenic health risk factors were used. The maximum combined individual health risk for simultaneous exposure to pollutants under the study was estimated to be 600 to 5,000 in one million.

At its October 10, 1997 meeting, the SCAQMD Governing Board directed staff to conduct MATES II to include a monitoring program of 40 known air toxic compounds, an updated emissions inventory of toxic air contaminants, and a modeling effort to characterize health risks from hazardous air pollutants. The estimated basin-wide carcinogenic health risk from ambient measurements was 1,400 per million people. About 70 percent of the basin wide health risk was attributed to diesel particulate emissions; about 20 percent to other toxics associated with mobile sources (including benzene, butadiene, and formaldehyde); about 10 percent of basin wide health risk was attributed to stationary sources (which include industrial sources and other certain specifically identified commercial businesses such as dry cleaners and print shops.) The

MATES III Study consists of a monitoring program, an updated emissions inventory of toxic air contaminants, and a modeling effort to characterize carcinogenic health risk across the Basin. Besides toxics, additional measurements include organic carbon, elemental carbon, and total carbon, as well as, Particulate Matter (PM), including PM2.5.

MATES III revealed a general downward trend in air toxic pollutant concentrations with an estimated basin-wide lifetime carcinogenic health risk of 1,200 in one million. However, an upward trend was observed in the port areas. Mobile sources accounted for 94 percent of the basin-wide lifetime carcinogenic health risk with diesel exhaust particulate contributing to 84 percent of the mobile source basin-wide lifetime carcinogenic health risk. Non-diesel carcinogenic health risk was reduced declined by 50 percent from the MATES II values.

Health Effects

Carcinogenic Health Risks from Toxic Air Contaminants

One of the primary health risks of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because it is currently believed by many scientists that there is no "safe" level of exposure to carcinogens. Any exposure to a carcinogen poses some risk of causing cancer. It is currently estimated that about one in four deaths in the United States is attributable to cancer. About two percent of cancer deaths in the United States may be attributable to environmental pollution (Doll and Peto 1981). The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods.

Non-Cancer Health Risks from Toxic Air Contaminants

Unlike carcinogens, for most TAC non-carcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA) develops Reference Exposure Levels (RELs) for TACs which are health-conservative estimates of the levels of exposure at or below which health effects are not expected. The non-cancer health risk due to exposure to a TAC is assessed by comparing the estimated level of exposure to the REL. The comparison is expressed as the ratio of the estimated exposure level to the REL, called the hazard index (HI).

Climate Change

Global climate change is a change in the average weather of the earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Data indicate that the current temperature record differs from previous climate changes in rate and magnitude.

Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse, which captures and traps radiant energy. GHGs are emitted by natural processes and human activities. The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbon (PFCs). The

GHGs absorb longwave radiant energy emitted by the Earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the Earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect." Emissions from human activities such as fossil fuel combustion for electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

CO2 is an odorless, colorless greenhouse gas. Natural sources include the following: decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of CO2 are from burning coal, oil, natural gas, and wood.

CH4 is a flammable gas and is the main component of natural gas. N2O, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes such as fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions also contribute to the atmospheric load of N2O. HFCs are synthetic man-made chemicals that are used as a substitute for chlorofluorocarbons (whose production was stopped as required by the Montreal Protocol) for automobile air conditioners and refrigerants. The two main sources of PFCs are primary aluminum production and semiconductor manufacture. SF6 is an inorganic, odorless, colorless, nontoxic, nonflammable gas. SF6 is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Scientific consensus, as reflected in recent reports issued by the United Nations Intergovernmental Panel on Climate Change, is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHGs in the atmosphere due to human activities. Industrial activities, particularly increased consumption of fossil fuels (e.g., gasoline, diesel, wood, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. The United Nations Intergovernmental Panel on Climate Change constructed several emission trajectories of greenhouse gases needed to stabilize global temperatures and climate change impacts. It concluded that a stabilization of greenhouse gases at 400 to 450 ppm carbon dioxide-equivalent concentration is required to keep global mean warming below two degrees Celsius, which is assumed to be necessary to avoid dangerous impacts from climate change.

The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, air quality impacts, and sea level rise. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (e.g., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other disease carrying insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding, hurricanes, and wildfires can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

The impacts of climate change will also affect projects in various ways. Effects of climate change are rising sea levels and changes in snow pack. The extent of climate change impacts at specific locations remains unclear. It is expected that Federal, State and local agencies will more precisely quantify impacts in various regions. As an example, it is expected that the California Department of Water Resources will formalize a list of foreseeable water quality issues associated with various degrees of climate change. Once state government agencies make these lists available, they could be used to more precisely determine to what extent a project creates global climate change impacts.

Federal

Greenhouse Gas Endangerment Findings
On December 7, 2009, the U.S. EPA Administrator signed two distinct findings regarding greenhouse gases under section 202(a) of the CAA. It was concluded in the Endangerment Finding that CO2, CH4, N2O, HFCs, PFCs, and SF6 taken in combination endanger both the public health and the public welfare of current and future generations. The Cause or Contribute Finding stated that the combined emissions from motor vehicles and motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare. These findings were a prerequisite for implementing GHG standards for vehicles. The U.S. EPA and the National Highway Traffic Safety Administration (NHTSA) finalized emission standards for light-duty vehicles in May 2010 and for heavy-duty vehicles in August of 2011.

Renewable Fuel Standard
The RFS program was established under the Energy Policy Act (EPAct) of 2005, which required 7.5 billion gallons of renewable-fuel to be blended into gasoline by 2012. Under the Energy Independence and Security Act (EISA) of 2007, the RFS program was expanded to include diesel, required the volume of renewable fuel blended into transportation fuel be increased from nine billion gallons in 2008 to 36 billion gallons by 2022, established new categories of renewable fuel and required U.S. EPA to apply lifecycle GHG performance threshold standards so that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces. The RFS is expected to reduce greenhouse gas emissions by 138 million metric tons, about the annual emissions of 27 million passenger vehicles, replacing about seven percent of expected annual diesel consumption and decreasing oil imports by $41.5 billion.

As a result of a ruling by U.S. Court of Appeals for D.C. in January 2013, US EPA took regulatory action proposing to establish the annual percentage standards for 2013 for cellulosic, biomass-based diesel, advanced biofuel, and total renewable fuels that apply to all gasoline and diesel produced or imported in year 2013.

GHG Tailoring Rule
On May 13, 2010, U.S. EPA finalized the Tailoring Rule to phase in the applicability of the PSD and Title V operating permit programs for GHGs. The rule was tailored to include the largest GHG emitters, while excluding smaller sources (restaurants, commercial facilities and small farms). The first step (January 2, 2011 to June 30, 2011) addressed the largest sources that contributed 65 percent of the stationary GHG sources. Title V GHG requirements were triggered only when affected facility owners/operators were applying, renewing or revising their permits

for non-GHG pollutants. PSD GHG requirements were applicable only if sources were undergoing permitting actions for other non-GHG pollutants and the permitted action would increase GHG emission by 75,000 metric tons of CO2e per year or more.

The second step (July 1, 2011 to June 30, 2013), included sources that emit or have the potential to emit 100,000 of CO2e metric tons per year or more. Newly constructed sources that are not major sources for non-GHG pollutants would not be subject to PSD GHG requirements unless it emits 100,000 tons of CO2e per year or more. Modifications to a major source would not be subject to PSD GHG requirements unless it generates a net increase of 75,000 tons of CO2e per year or more. Sources not subject to Title V would not be subject to Title V GHG requirements unless 100,000 tons of CO2e per year or more would be emitted.

The third step of the Tailoring Rule was finalized on July 12, 2012. The third step determined not to not to lower the current PSD and Title V applicability thresholds for GHG-emitting sources established in the Tailoring Rule for Steps 1 and 2. The rule also promulgates regulatory revisions for better implementation of the federal program for establishing plantwide applicability limitations (PALs) for GHG emissions, which will improve the administration of the GHG PSD permitting programs.

GHG Reporting Program
U.S. EPA issued the Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) under the 2008 Consolidated Appropriations Act. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHG data from large sources and suppliers under the Greenhouse Gas Reporting Program (GHGRP). Suppliers of certain products that would result in GHG emissions if released, combusted or oxidized; direct emitting source categories; and facilities that inject CO_2 underground for geologic sequestration or any purpose other than geologic sequestration are included. Facilities that emit 25,000 metric tons or more per year of GHGs in CO2 equivalents (CO2e) are required to submit annual reports to U.S. EPA. For the 2010 calendar, there were 6,260 entities that reported GHG data under this program, and 467 of the entities reporting were from California. Of the 3,200 million metric tons of CO2e that were reported nationally, 112 million metric tons were from California Power plants were the largest stationary source of direct U.S. GHG emissions with 2,326 million metric tons of CO2e, followed by refineries with 183 million metric tons of CO2e. CO2 emissions accounted for largest share of direct emissions with 95 percent, followed by methane with four percent, and nitrous oxide and fluorinated gases representing the remaining one percent.

<u>*State*</u>

Executive Order S-3-05
In June 2005, then Governor Schwarzenegger signed Executive Order S-3-05, which established emission reduction targets. The goals would reduce GHG emissions to 2000 levels by 2010, then to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050.

AB 32: Global Warming Solutions Act
On September 27, 2006, Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006, was enacted by the State of California and signed by Governor Schwarzenegger. AB 32

expanded on Executive Order #S-3-05. The legislature stated that "global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." AB 32 represents the first enforceable state-wide program in the United States to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB 32 lays out a program to inventory and reduce greenhouse gas emissions in California and from power generation facilities located outside the state that serve California residents and businesses.

AB 32 requires CARB to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions by January 1, 2008;
- Adopt mandatory reporting rules for significant sources of GHG by January 1, 2008;
- Adopt an emissions reduction plan by January 1, 2009, indicating how emissions reductions will be achieved via regulations, market mechanisms, and other actions; and
- Adopt regulations to achieve the maximum technologically feasible and cost-effective reductions of GHG by January 1, 2011.

The combination of Executive Order #S-3-05 and AB 32 will require significant development and implementation of energy efficient technologies and shifting of energy production to renewable sources.

Consistent with the requirement to develop an emission reduction plan, CARB prepared a Scoping Plan indicating how GHG emission reductions will be achieved through regulations, market mechanisms, and other actions. The Scoping Plan was released for public review and comment in October 2008 and approved by CARB on December 11, 2008. The Scoping Plan calls for reducing greenhouse gas emissions to 1990 levels by 2020. This means cutting approximately 30 percent from business-as-usual (BAU) emission levels projected for 2020, or about 15 percent from today's levels. Key elements of CARB staff's recommendations for reducing California's greenhouse gas emissions to 1990 levels by 2020 contained in the Scoping Plan include the following:

- Expansion and strengthening of existing energy efficiency programs and building and appliance standards;
- Expansion of the Renewables Portfolio Standard to 33 percent;
- Development of a California cap-and-trade program that links with other Western Climate Initiative (WCI) Partner programs to create a regional market system;
- Establishing targets for transportation-related greenhouse gases and pursuing policies and incentives to achieve those targets;
- Adoption and implementation of existing State laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard; and
- Targeted fees, including a public good charge on water use, fees on high GWP gases and a fee to fund the state's long-term commitment to AB 32 administration.

In response to the comments received on the Draft Scoping Plan and at the November 2008 public hearing, CARB made a few changes to the Draft Scoping Plan, primarily to:

- State that California "will transition to 100 percent auction" of allowances and expects to "auction significantly more [allowances] than the Western Climate Initiative minimum;"
- Make clear that allowance set-asides could be used to provide incentives for voluntary renewable power purchases by businesses and individuals and for increased energy efficiency;
- Make clear that allowance set-asides can be used to ensure that voluntary actions, such as renewable power purchases, can be used to reduce greenhouse gas emissions under the cap;
- Provide allowances are not required from carbon neutral projects; and
- Mandate that commercial recycling be implemented to replace virgin raw materials with recyclables.

In 2009, total California greenhouse gas emissions were 457 million metric tons of carbon dioxide equivalent (MMTCO2e); net emissions were 453 MMTCO2e, reflecting the influence of sinks (net CO2 flux from forestry). While total emissions have increased by 5.5 percent from 1990 to 2009, emissions decreased by 5.8 percent from 2008 to 2009 (485 to 457 MMTCO2e). The total net emissions between 2000 and 2009 decreased from 459 to 453 MMTCO2e, representing a 1.3 percent decrease from 2000 and a 6.1 percent increase from the 1990 emissions level. The transportation sector accounted for approximately 38 percent of the total emissions, while the industrial sector accounted for approximately 20 percent. Emissions from electricity generation were about 23 percent with almost equal contributions from in-state and imported electricity.

Per capita emissions in California have slightly declined from 2000 to 2009 (by 9.7 percent), but the overall nine percent increase in population during the same period offsets the emission reductions. From a per capita sector perspective, industrial per capita emissions have declined 21 percent from 2000 to 2009, while per capita emissions for ODCs substitutes saw the highest increase (52 percent).

From a broader geographical perspective, the state of California ranked second in the United States for 2007 greenhouse gas emissions, only behind Texas. However, from a per capita standpoint, California had the 46th lowest GHG emissions. On a global scale, California had the 14th largest carbon dioxide emissions and the 19th largest per capita emissions. The GHG inventory is divided into three categories: stationary sources, on-road mobile sources, and off-road mobile sources.

AB 1493 Vehicular Emissions: Carbon Dioxide

Prior to the U.S. EPA and NHTSA joint rulemaking, the Governor signed Assembly Bill (AB) 1493 (2002). AB 1493 requires that CARB develop and adopt, by January 1, 2005, regulations that achieve "the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks and other vehicles determined by CARB to be vehicles whose primary use is noncommercial personal transportation in the state."

CARB originally approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009 (Amendments to CCR Title 13, Sections 1900 and 1961 (13 CCR 1900, 1961), and adoption of Section 1961.1 (13 CCR 1961.1)). California's first request to the U.S. EPA to implement GHG standards for passenger vehicles was made in December 2005 and denied in March 2008. The U.S. EPA then granted California the authority to implement GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles on June 30, 2009.

On April 1, 2010, the CARB filed amended regulations for passenger vehicles as part of California's commitment toward the National Program to reduce new passenger vehicle GHGs from 2012 through 2016. The amendments will prepare California to harmonize its rules with the federal Light-Duty Vehicle GHG Standards and CAFE Standards (discussed above).

Senate Bill 1368 (2006)
SB 1368 is the companion bill of AB 32 and was signed by Governor Schwarzenegger in September 2006. SB 1368 requires the California Public Utilities Commission (PUC) to establish a greenhouse gas emission performance standard for baseload generation from investor owned utilities by February 1, 2007. The California Energy Commission (CEC) must establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the greenhouse gas emission rate from a baseload combined-cycle natural gas fired plant. The legislation further requires that all electricity provided to California, including imported electricity, must be generated from plants that meet the standards set by the PUC and CEC.

Executive Order S-1-07 (2007)
Governor Schwarzenegger signed Executive Order S-1-07 in 2007 which finds that the transportation sector is the main source of GHG emissions in California. The executive order proclaims the transportation sector accounts for over 40 percent of statewide GHG emissions. The executive order also establishes a goal to reduce the carbon intensity of transportation fuels sold in California by a minimum of 10 percent by 2020.

In particular, the executive order established a Low-Carbon Fuel Standard (LCFS) and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, the ARB, the University of California, and other agencies to develop and propose protocols for measuring the "life-cycle carbon intensity" of transportation fuels. This analysis supporting development of the protocols was included in the State Implementation Plan for alternative fuels (State Alternative Fuels Plan adopted by CEC on December 24, 2007) and was submitted to CARB for consideration as an "early action" item under AB 32. CARB adopted the LCFS on April 23, 2009.

Senate Bill 375 (2008)
SB 375, signed in September 2008, aligns regional transportation planning efforts, regional GHG reduction targets, and land use and housing allocation. As part of the alignment, SB 375 requires Metropolitan Planning Organizations (MPOs) to adopt a Sustainable Communities Strategy (SCS) or Alternative Planning Strategy (APS) which prescribes land use allocation in that MPO's Regional Transportation Plan (RTP). CARB, in consultation with MPOs, is required to provide each affected region with reduction targets for GHGs emitted by passenger cars and light trucks in the region for the years 2020 and 2035. These reduction targets will be updated every eight years but can be updated every 4 years if advancements in emissions technologies affect the reduction strategies to achieve the targets. CARB is also charged with reviewing each

MPO's SCS or APS for consistency with its assigned GHG emission reduction targets. If MPOs do not meet the GHG reduction targets, transportation projects located in the MPO boundaries would not be eligible for funding programmed after January 1, 2012.

CARB appointed the Regional Targets Advisory Committee (RTAC), as required under SB 375, on January 23, 2009. The RTAC's charge was to advise ARB on the factors to be considered and methodologies to be used for establishing regional targets. The RTAC provided its recommendation to CARB on September 29, 2009. The final targets were part of the 2012 Regional Transportation Plan (RTP) and are included in the 2012 AQMP.

Executive Order S-13-08 (2008)

Governor Schwarzenegger signed Executive Order S-13-08 on November 14, 2008 which directs California to develop methods for adapting to climate change through preparation of a statewide plan. The executive order directs OPR, in cooperation with the Resources Agency, to provide land use planning guidance related to sea level rise and other climate change impacts by May 30, 2009. The order also directs the Resources Agency to develop a state Climate Adaptation Strategy by June 30, 2009 and to convene an independent panel to complete the first California Sea Level Rise Assessment Report. The assessment report is required to be completed by December 1, 2010 and required to meet the following four criteria:

1. Project the relative sea level rise specific to California by taking into account issues such as coastal erosion rates, tidal impacts, El Niño and La Niña events, storm surge, and land subsidence rates;
2. Identify the range of uncertainty in selected sea level rise projections;
3. Synthesize existing information on projected sea level rise impacts to state infrastructure (e.g., roads, public facilities, beaches), natural areas, and coastal and marine ecosystems; and
4. Discuss future research needs relating to sea level rise in California.

Senate Bills 1078 and 107 and Executive Order S-14-08 (2008)

SB 1078 (Chapter 516, Statutes of 2002) requires retail sellers of electricity, including investor owned utilities and community choice aggregators, to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, then Governor Schwarzenegger signed Executive Order S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020.

SB X-1-2

SB X1-2 was signed by Governor Edmund G. Brown, Jr., in April 2011. SB X1-2 created a new Renewables Portfolio Standard (RPS), which preempted the CARB's 33 percent Renewable Electricity Standard. The new RPS applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. These entities must adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement by the end of 2020.

SCAQMD
The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy commits the SCAQMD to consider global impacts in rulemaking and in drafting revisions to the AQMP. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include support of the adoption of a California greenhouse gas emission reduction goal.

Basin GHG Policy and Inventory
The SCAQMD has established a policy, adopted by the SCAQMD Governing Board at its September 5, 2008 meeting, to actively seek opportunities to reduce emissions of criteria, toxic, and climate change pollutants. The policy includes the intent to assist businesses and local governments implementing climate change measures, decrease the agency's carbon footprint, and provide climate change information to the public.

On December 5, 2008, the SCAQMD Governing Board adopted the staff proposal for an interim GHG significance threshold for projects where the SCAQMD is lead agency. SCAQMD's recommended interim GHG significance threshold proposal uses a tiered approach to determining significance. Tier 1 consists of evaluating whether or not the project qualifies for any applicable exemption under CEQA. Tier 2 consists of determining whether or not the project is consistent with a GHG reduction plan that may be part of a local general plan, for example. Tier 3 establishes a screening significance threshold level to determine significance using a 90 percent emission capture rate approach, which corresponds to 10,000 metric tons of CO2 equivalent emissions per year (MTCO2e/year). Tier 4, to be based on performance standards, is yet to be developed. Under Tier 5 the project proponent would allow offsets to reduce GHG emission impacts to less than the proposed screening level. If CARB adopts statewide significance thresholds, SCAQMD staff plans to report back to the SCAQMD Governing Board regarding any recommended changes or additions to the SCAQMD's interim threshold.

Table 3-7 presents the GHG emission inventory by major source categories in calendar year 2008, as identified in the 2012 AQMP, for the Basin. The emissions reported herein are based on in-basin energy consumption and do not include out-of-basin energy production (e.g., power plants, crude oil production) or delivery emissions (e.g., natural gas pipeline loss). Three major GHG pollutants have been included: CO2, N2O, and CH4. These GHG emissions are reported in MMTCO2e. Mobile sources generate 59.4 percent of the emissions and include not only vehicles, but also construction equipment, airport equipment, and oil and gas drilling equipment. The remaining 40.6 percent of the total Basin GHG emissions are from stationary and area sources. The largest stationary/area source is fuel combustion, which is 27.8 percent of the total Basin GHG emissions (68.6 percent of the GHG emissions from the stationary and area source category).

Air Quality – Ozone Depletion
The Montreal Protocol on Substances that Deplete the Ozone Layer (Montreal Protocol) is an international treaty designed to phase out halogenated hydrocarbons (chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs)), which are considered ozone depleting compounds (ODCs)). The Montreal Protocol was first signed in September 16, 1987 and has

been revised seven times. The United States ratified the original Montreal Protocol and each of its revisions.

Federal

Under Title VI of the CAA, U.S. EPA is responsible for programs that protect the stratospheric ozone layer. Title 40, Part 82 of the Code of Federal Regulations contains U.S. EPA's regulations to protect the ozone layer. U.S. EPA regulations phase out the production and import of ODCs consistent with the Montreal Protocol. ODCs are typically used as refrigerants or as foam blowing agents. ODCs are regulated as Class I or Class II controlled substances. Class I substances have a higher ozone-depleting potential and have been completely phased out in the U.S., except for exemptions allowed under the Montreal Protocol. Class II substances are hydrochlorofluorocarbons (HCFCs), which are transitional substitutes for many Class I substances and are being phased out.

State

AB 32: Global Warming Solutions Act

Some ODCs exhibit high global warming potentials. As stated in Section 3.2.3.1, ARB developed a cap and trade regulation under AB 32. The cap and trade regulation includes the Compliance Offset Protocol Ozone Depleting Substances Projects, which provides methods to quantify and report GHG emission reductions associated with the destruction of high global warming potential ODCs sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. The protocol must be used to quantify and report GHG reductions under the ARB's GHG Cap and Trade Regulation.

Refrigerant Management Program

As part AB 32, ARB adopted a regulation (Refrigerant Management Program) in 2009 to reduce GHG emissions from stationary sources through refrigerant leak detection and monitoring, leak repair, system retirement and retrofitting, reporting and recordkeeping, and proper refrigerant cylinder use, sale, and disposal.

TABLE 3-7
2008 GHG Emissions for Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
Fuel Combustion								
10	Electric Utilities	34,303	.08	0.71	12,520,562	29.0	258	11.4
20	Cogeneration	872	.00	0.02	318,340	0.60	6.00	0.29
30	Oil and Gas Production (combustion)	2,908	.01	0.08	1,061,470	4.71	29.5	0.96
40	Petroleum Refining (Combustion)	44,654	.06	0.57	16,298,766	20.7	207	14.8
50	Manufacturing and Industrial	22,182	.06	0.48	8,096,396	20.9	174	7.35
52	Food and Agricultural Processing	927	00	0.02	338,516	0.84	7.16	0.31
60	Service and Commercial	21,889	0.08	0.59	7,989,416	30.8	215	7.26
99	Other (Fuel Combustion)	2,241	0.2	0.16	818,057	8.58	58	0.75
Total Fuel Combustion		**129,977**	**0.32**	**2.62**	**47,441,523**	**116**	**956**	**43.1**
Waste Disposal								
110	Sewage Treatment	26.4	0.00	0.00	9,653	0.12	1.50	0.01
120	Landfills	3,166	0.04	505	1,155,509	14.0	184,451	4.57
130	Incineration	580	0.00	0.02	211,708	0.81	5.48	0.19
199	Other (Waste Disposal)			2.25	0	0.00	820	0.02
Total Waste Disposal		**3,772**	**0.04**	**508**	**1,376,870**	**14.9**	**185,278**	**4.78**
Cleaning and Surface Coatings								
210	Laundering							
220	Degreasing							
230	Coatings and Related Processes	27.1	0.00	0.21	9,890	0.02	78.0	0.01
240	Printing			0.00	0	0.00	0.00	0.00
250	Adhesives and Sealants			0.00	0	0.00	0.00	0.00
299	Other (Cleaning and Surface Coatings)	2,621	0.00	0.12	956,739	1.20	43.9	0.87
Total Cleaning and Surface Coatings		**2,648**	**0.00**	**0.33**	**966,628**	**1.22**	**122**	**0.88**
Petroleum Production and Marketing								
310	Oil and Gas Production	92.1	0.00	0.92	33,605	0.06	336	0.04
320	Petroleum Refining	770	0.00	1.65	280,932	0.36	603	0.27
330	Petroleum Marketing			83.8	0	0.00	30,598	0.58
399	Other (Petroleum Production and Marketing)			0.00	0	0.00	0	0.00
Total Petroleum Production and Marketing		**862**	**0.00**	**86.4**	**314,536**	**0.42**	**31,537**	**0.89**

TABLE 3-7 (Continued)
2008 GHG Emissions for Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	Source Category	CO2	N2O	CH4	CO2	N2O	CH4	CO2e
Industrial Processes								
410	Chemical			0.92	0	0.00	337	0.01
420	Food and Agriculture			0.02	0	0.00	7.10	0.00
430	Mineral Processes	279	0.00	0.05	101,804	0.19	17.3	0.09
440	Metal Processes			0.02	0	0.00	9.10	0.00
450	Wood and Paper			0.00	0	0.00	0.00	0.00
460	Glass and Related Products			0.00	0	0.00	0.90	0.00
470	Electronics			0.00	0	0.00	0.00	0.00
499	Other (Industrial Processes)	0.08	0.00	0.47	28	0.00	172	0.00
Total Industrial Processes		**279**	**0.00**	**1.49**	**101,832**	**0.19**	**543**	**0.10**
Solvent Evaporation								
510	Consumer Products			0.00	0.00	0.00	0.00	0.00
520	Architectural Coatings and Related Solvent			0.00	0.00	0.00	0.00	0.00
530	Pesticides/Fertilizers			0.00	0.00	0.00	0.00	0.00
540	Asphalt Paving/Roofing			0.07	0.00	0.00	24.20	0.00
Total Solvent Evaporation		**0.00**	**0.00**	**0.07**	**0.00**	**0.00**	**24.20**	**0.00**
Miscellaneous Processes								
610	Residential Fuel Combustion	38,850	0.12	0.95	14,180,326	45.3	347	12.9
620	Farming Operations			25.6	0.00	0.00	9,354	0.18
630	Construction and Demolition			0.00	0.00	0.00	0	0.00
640	Paved Road Dust			0.00	0.00	0.00	0	0.00
645	Unpaved Road Dust			0.00	0.00	0.00	0	0.00
650	Fugitive Windblown Dust			0.00	0.00	0.00	0	0.00
660	Fires			0.08	0.00	0.00	30.9	0.00
670	Waste Burning and Disposal			0.58	0.00	0.00	212	0.00
680	Utility Equipment				0.00	0.00		0.00
690	Cooking			0.64	0.00	0.00	235	0.00
699	Other (Miscellaneous Processes			0.00	0.00	0.00	0	0.00
Total Miscellaneous Processes		**38,850**	**0.12**	**27.9**	**14,180,326**	**45.3**	**10,179**	**13.1**

TABLE 3-7 (Concluded)
2008 GHG Emissions for Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
On-Road Motor Vehicles								
710	Light Duty Passenger Auto (LDA)	84,679	2.72	3.62	30,907,957	993	1,321	28.3
722	Light Duty Trucks 1 (T1 : up to 3750 lb.)	22,319	0.72	0.96	8,146,321	263	350	7.47
723	Light Duty Trucks 2 (T2 : 3751-5750 lb.)	33,495	1.08	1.43	12,225,619	392	523	11.2
724	Medium Duty Trucks (T3 : 5751-8500 lb.)	29,415	0.94	1.25	10,736,309	343	456	9.85
732	Light Heavy Duty Gas Trucks 1 (T4 : 8501-10000 lb.)	8,195	0.16	0.21	2,991,059	57.3	76.7	2.73
733	Light Heavy Duty Gas Trucks 2 (T5 : 10001-14000 lb.)	1,116	0.05	0.07	407,174	19.0	25.6	0.38
734	Medium Heavy Duty Gas Trucks (T6 : 14001-33000 lb.)	727	0.02	0.20	265,506	5.48	73.0	0.24
736	Heavy Heavy Duty Gas Trucks ((HHDGT > 33000 lb.)	102	0.01	0.01	37,198	2.19	2.56	0.03
742	Light Heavy Duty Diesel Trucks 1 (T4 : 8501-10000 lb.)	2,166	0.02	0.02	790,600	6.94	7.30	0.72
743	Light Heavy Duty Diesel Trucks 2 (T5 : 10001-14000 lb.)	735	0.01	0.01	268,413	2.56	2.92	0.24
744	Medium Heavy Duty Diesel Truck (T6 : 14001-33000 lb.)	5,422	0.02	0.02	1,978,974	8.40	8.76	1.80
746	Heavy Heavy Duty Diesel Trucks (HHDDT > 33000 lb.)	17,017	0.05	0.05	6,211,247	17.5	16.4	5.64
750	Motorcycles (MCY)	7,959	0.26	0.34	2,904,910	94.9	124	2.66
760	Diesel Urban Buses (UB)	2,135	0.00	0.00	779,389	1.46	1.46	0.71
762	Gas Urban Buses (UB)	166	0.02	0.02	60,654	8.40	6.94	0.06
770	School Buses (SB)	337	0.00	0.00	122,995	1.46	1.46	0.11
776	Other Buses (OB)	927	0.00	0.00	338,430	0.73	0.73	0.31
780	Motor Homes (MH)	568	0.03	0.04	207,431	11.0	14.6	0.19
Total On-Road Motor Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**72.7**
Other Mobile Sources								
810	Aircraft	37,455	0.10	0.09	13,670,930	36.5	31.8	12.4
820	Trains	586	0.00	0.00	213,835	0.45	1.38	0.19
830	Ships and Commercial Boats	3,452	0.01	0.02	1,259,927	2.64	8.13	1.14
	Other Off-road sources (construction equipment, airport equipment, oil and gas drilling equipment)	16,080	1.72	8.84	5,869,123	628	3,226	5.56
Total Other Mobile Sources		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19.3**
Total Stationary and Area Sources		**176,388**	**0.49**	**626**	**64,381,716**	**178**	**228,639**	**63**
Total On-Road Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**73**
Total Other Mobile*		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19**
Total 2008 Baseline GHG Emissions for Basin		**451,440**	**8.42**	**644**	**164,775,719**	**1,001**	**232,094**	**155**

HFC Emission Reduction Measures for Mobile Air Conditioning - Regulation for Small Containers of Automotive Refrigerant

The automotive refrigerant small containers regulation applies to the sale, use, and disposal of small containers of automotive refrigerant with a GWP greater than 150. Emission reductions are achieved through implementation of four requirements: 1) use of a self-sealing valve on the container, 2) improved labeling instructions, 3) a deposit and recycling program for small containers, and 4) an education program that emphasizes best practices for vehicle recharging. This regulation went into effect on January 1, 2010 with a one-year sell-through period for containers manufactured before January 1, 2010. The target recycle rate is initially set at 90 percent, and rose to 95 percent beginning January 1, 2012.

SCAQMD

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy targeted a transition away from chlorofluorocarbons (CFCs) as an industrial refrigerant and propellant in aerosol cans. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include the following directives for ODSs:

- Phase out the use and corresponding emissions of chlorofluorocarbons (CFCs), methyl chloroform (1,1,1-trichloroethane or TCA), carbon tetrachloride, and halons by December 1995;
- Phase out the large quantity use and corresponding emissions of hydrochlorofluorocarbons (HCFCs) by the year 2000;
- Develop recycling regulations for HCFCs; and
- Develop an emissions inventory and control strategy for methyl bromide.

Rule 1122 – Solvent Degreasers

Rule 1112 applies to all persons who own or operate batch-loaded cold cleaners, open-top vapor degreasers, all types of conveyorized degreasers, and air-tight and airless cleaning systems that carry out solvent degreasing operations with a solvent containing Volatile Organic Compounds (VOCs) or with a NESHAP halogenated solvent. Some ODSs (carbon tetrachloride and 1,1,1-trichloroethane) are NESHAP halogenated solvents.

Rule 1150.1 – Control of Gaseous Emissions from Active Landfills

Rule 1150.1 reduces non-methane organic compounds (NMOC), volatile organic compound (VOC) and toxic air contaminant (TAC) emissions from Municipal Solid Waste (MSW) landfills to prevent public nuisance and possible detriment to public health caused by exposure to such emissions. This rule also reduces methane emissions, a greenhouse gas.

Rule 1171 – Solvent Cleaning Operations

Rule 1171 reduces emissions of volatile organic compounds (VOCs), toxic air contaminants, and stratospheric ozone-depleting or global warming compounds from the use, storage and disposal of solvent cleaning materials in solvent cleaning operations and activities

Rule 1415 – Reduction of Refrigerant Emissions from Stationary Air Conditioning Systems
Rule 1415 reduces emissions of high-global warming potential refrigerants from stationary air conditioning systems by requiring persons subject to this rule to reclaim, recover, or recycle refrigerant and to minimize refrigerant leakage.

Rule 1415.1 – Reduction of Refrigerant Emissions from Stationary Refrigeration Systems
Rule 1415.1 reduce emissions of high global warming potential refrigerants from stationary refrigeration systems by requiring persons subject to this rule to recover, recycle, or reclaim refrigerant and to minimize refrigerant leaks.

ENERGY

This subsection describes existing regulatory setting relative to energy production and demand, including alternative and renewable fuels, and trends within California and the district.

Regulatory Setting
Federal and state agencies regulate energy use and consumption through various means and programs. On the federal level, the United States Department of Transportation (U.S. DOT), United States Department of Energy (U.S. DOE), and United States Environmental Protection Agency (U.S. EPA) are three agencies with substantial influence over energy policies and programs. Generally, federal agencies influence transportation energy consumption through establishment and enforcement of fuel economy standards for automobiles and light trucks, through funding of energy related research and development projects, and through funding for transportation infrastructure projects.

On the state level, the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and California Independent System Operator Corporation (CAISO) are three entities with authority over different aspects of energy. The CPUC regulates privately-owned utilities in the energy, rail, passenger transportation, telecommunications, and water fields. The CEC collects and analyzes energy-related data, prepares state-wide energy policy recommendations and plans, promotes and funds energy efficiency and renewable energy resources programs, plans and directs state response to energy emergencies, and regulates the power plant siting and transmission process. CAISO operates a rebust and reliable wholesale power system that balances the need for higher transmission reliability with the need for lower costs, and acts as a key platform to achieve California's clean energy goals. Some of the more relevant federal and state energy-related laws and plans are discussed in the following subsections.

<u>Federal Regulations</u>

National Energy Act
The National Energy Act of 1978 included the following statutes: Energy Tax Act, National Energy Conservation Policy Act, Power Plant and Industrial Fuel Use Act, and the National Gas Policy Act. The Power Plant and Industrial Fuel Use Act restricted the fuel used in power plants, however, these restrictions were lifted in 1987. The Energy Tax Act was superseded by the Energy Policy Acts of 1992 and 2005. The National Gas Policy Act gave the Federal Energy

Regulatory Commission authority over natural gas production and established pricing guidelines. The National Energy Conservation Policy Act (NECPA). The NECPA set minimum energy performance standards, which replaced those in the EPCA. The federal standards preempted state standards. The NECPA was amended by the Energy Policy and Conservation Act Amendments of 1985.

Public Utility Regulatory Policies Act of 1978 (PURPA) (Public Law 95-617)
PURPA was passed in response to the unstable energy climate of the late 1970s. PURPA sought to promote conservation of electric energy. Additionally, PURPA created a new class of nonutility generators, small power producers, from which, along with qualified co-generators, utilities are required to buy power.

PURPA was in part intended to augment electric utility generation with more efficiently produced electricity and to provide equitable rates to electric consumers. Utility companies are required to buy all electricity from qualifying facilities (Qfs) at avoided cost (avoided costs are the incremental savings associated with not having to produce additional units of electricity). PURPA expanded participation of nonutility generators in the electricity market and demonstrated that electricity from nonutility generators could successfully be integrated with a utility's own supply. PURPA requires utilities to buy whatever power is produced by Qfs (usually cogeneration or renewable energy). The Fuel Use Act (FUA) of 1978 (repealed in 1987) also helped Qfs become established. Under FUA, utilities were not allowed to use natural gas to fuel new generating technologies, but Qfs, which were by definition not utilities, were able to take advantage of abundant natural gas and abundant new technologies (such as combined-cycle).

Energy Policy Act of 1992
The Energy Policy Act of 1992 is comprised of twenty-seven titles. It addressed clean energy use and overall national energy efficiency to reduce dependence on foreign energy, incentives for clean, radioactive waste protection standards, and renewable energy and energy conservation in buildings and efficiency standards for appliances.

Energy Policy Act of 2005
The Energy Policy Act of 2005 addresses energy efficiency; renewable energy requirements; oil, natural gas and coal; alternative-fuel use; tribal energy, nuclear security; vehicles and vehicle fuels, hydropower and geothermal energy, and climate change technology. The Act provides revised annual energy reduction goals (two percent per year beginning in 2006), revised renewable energy purchase goals, federal procurement of Energy Star or Federal Energy Management Program-designated products, federal green building standards, and fuel cell vehicle and hydrogen energy system research and demonstration.

Energy Independence and Security Act of 2007 (EISA)
The Energy Independence and Security Act of 2007 was signed into law by President Bush on December 19, 2007. The Acts objectives are to move the United States toward greater energy independence and security, increase the production of clean renewable fuels, protect consumers, increase the efficiency of products, buildings and vehicles, promote greenhouse gas research, improve the energy efficiency of the Federal government, and improve vehicle fuel economy.

State Regulations

The CEC and CPUC have jurisdiction over the investor-owned utilities (IOUs) in California. Within the District, the CEC also collects information for the Los Angeles Department of Water and Power (LADWP) and other municipal utilities including Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale and Pasadena, Riverside, Vernon and Imperial Irrigation District. CAISO operates a rebust and reliable wholesale power system that balances the need for higher transmission reliability with the need for lower costs, and acts as a key platform to achieve California's clean energy goals. The applicable state regulations, laws, and executive orders relevant to energy use are discussed below.

California Building Energy Efficiency Standards: Title 24

California established statewide building energy efficiency standards following legislative action. The legislation required the standards to be cost-effective based on the building life cycle and to include both prescriptive and performance-based approaches. The 2005 Building Energy Efficiency Standards were adopted in November 2003, took effect October 1, 2005, and followed by a 2008 update.

AB 1007, Alternative Fuels Plan

Assembly Bill (AB) 1007, (Pavley, Chapter 371, Statutes of 2005) requires the CEC to prepare a state plan to increase the use of alternative fuels in California (Alternative Fuels Plan). The CEC prepared the plan in partnership with CARB, and in consultation with the other state, federal and local agencies in December 2007. The Alternative Fuels Plan assessed various alternative fuels and developed fuel portfolios to meet California's goals to reduce petroleum consumption, increase alternative fuels use, reduce GHG emissions, and increase in-state production of biofuels without causing a significant degradation of public health and environmental quality.

Senate Bill (SB) 1368, Greenhouse Gas Emissions Performance Standard for Major Power Plant Investments

This law requires the CEC to develop and adopt by regulation a greenhouse gas emissions performance standard for long-term procurement of electricity by local publicly-owned utilities. The CEC must adopt the standard on or before June 30, 2007 and must be consistent with the standard adopted by the CPUC for load-serving entities under their jurisdiction on or before February 1, 2007. On January 25, 2007, and on May 23, 2007, respectively, the CPUC and the CEC adopted specific regulations regarding greenhouse gas emissions performance standards for IOUs and other electricity service providers under SB 1368. Compliance with these standards is expected to improve fuel use.

California Solar Initiative

On January 12, 2006, the CPUC approved the California Solar Initiative (CSI), which provides \$2.9 billion in incentives between 2007 and 2017. CSI is part of the Go Solar California campaign, and builds on 10 years of state solar rebates offered to California's IOU territories: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E.) The California Solar Initiative is overseen by the CPUC, and includes a \$2.5 billion program for commercial and existing residential customers, funded through revenues and collected from gas and electric utility distribution rates. Furthermore, the CEC will manage \$350 million targeted for new residential building construction, utilizing funds already allocated to the CEC to foster renewable projects between 2007 and 2011.

Current incentives provide an upfront, capacity-based payment for a new system. In its August 24, 2006 decision, the CPUC shifted the program from volume-based to performance-based incentives and clarified many elements of the program's design and administration. These changes were enacted in 2007, when the CSI incentive system changed to performance-based payments.

Renewables Portfolio Standard
California's renewables portfolio standard (RPS) requires retail sellers of electricity to increase their procurement of eligible renewable energy resources by at least one percent per year so that 20 percent of their retail sales are procured from eligible renewable energy resources by 2017. If a seller falls short in a given year, they must procure more renewables in succeeding years to make up the shortfall. Once a retail seller reaches 20 percent, they need not increase their procurement in succeeding years. RPS was enacted via SB 1078 (Sher), signed September 2002 by Governor Davis. The CEC and the CPUC are jointly implementing the standard. In 2006, RPS was modified by Senate Bill 107 to require retail sellers of electricity to reach the 20 percent renewables goal by 2010. In 2011, RPS was further modified by Senate Bill 2 to require retailers to reach 33 percent renewable energy by 2020.

California Environmental Quality Act (CEQA)
Appendix F of the CEQA Guidelines describes the types of information and analyses related to energy conservation that are to be included in EIRs that are prepared pursuant to CEQA. In Appendix F of the CEQA Guidelines, energy conservation is described in terms of decreased per capita energy consumption, decreased reliance on natural gas and oil, and increased reliance on renewable energy sources. To assure that energy implications are considered in project decisions, EIRs must include a discussion of the potentially significant energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful and unnecessary consumption of energy.

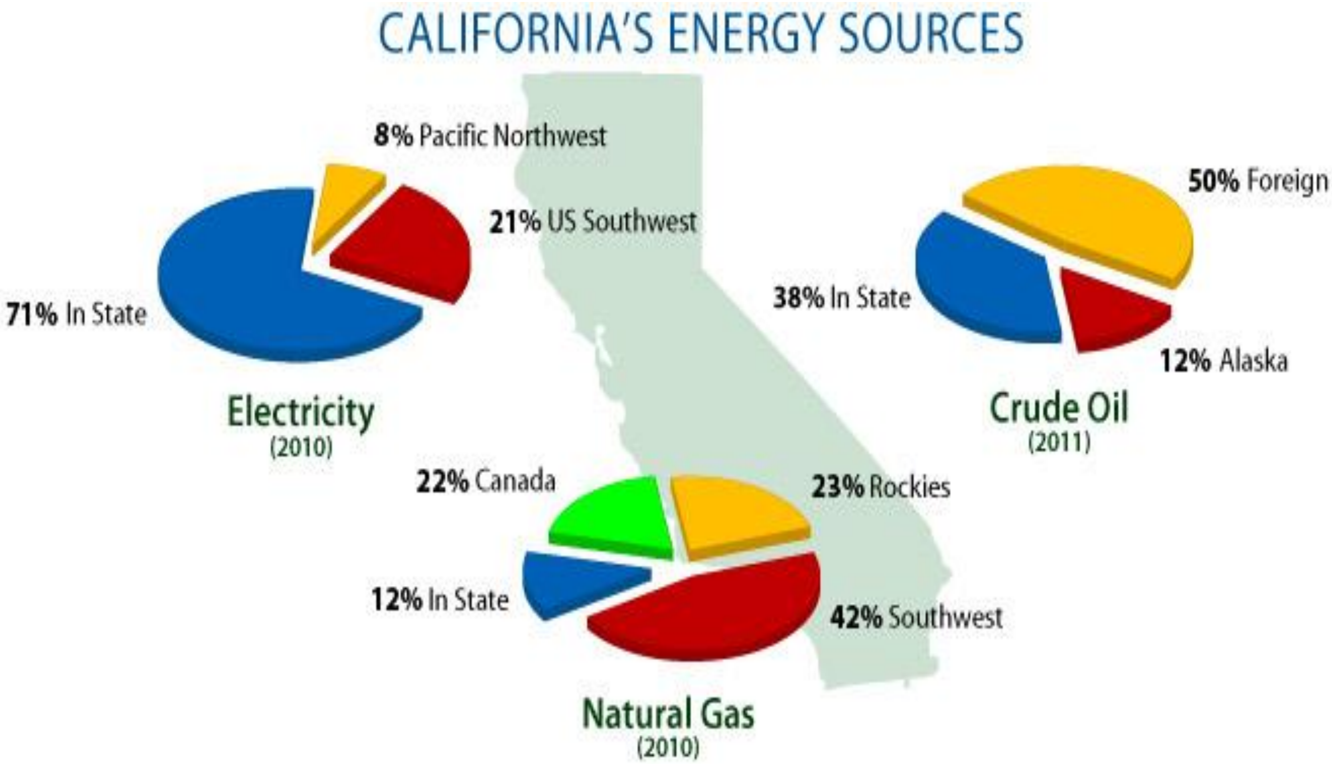
Local Regulations

San Gabriel Valley Energy Efficiency Partnership

In April 2006, the SCAG's Regional Council authorized SCAG's Executive Director to enter into a partnership with SCE to incentivize energy efficiency programs in the San Gabriel Valley Subregion. The San Gabriel Valley Energy Wise Program (SGVEWP) agreement was fully executed on October 20, 2006 with the main goal to save a combined three million kilowatt-hours (kWh) by providing technical assistance and incentive packages to cities by 2008. The program has been extended and seeks to reduce energy usage in the region by approximately five million kWh by 2012. The SGVEWP is funded by California utility customers and administered by SCE under the auspices of the CPUC.

Energy Trends In General (Statewide)
Figure 3-2 shows California's major sources of energy. In 2010, 71 percent of the electricity came from in-state sources, while 29 percent was imported into the state. The electricity imported totaled 85,169 gigawatt hours (GWh), with 24,677 GWh coming from the Pacific Northwest, and 60,492 GWh from the Southwest. (Note: A gigawatt is equal to one million kilowatts). For natural gas in 2010, 42 percent came from the Southwest, 22 percent from

Canada, 12 percent from in-state, and 23 percent from the Rockies. Also in 2010, 38 percent of the crude oil came from in state, with 12 percent coming from Alaska, and 50 percent being supplied by foreign sources (CEC, 2012).



Source: California Energy Commission

FIGURE 3-2

California's Major Sources of Energy

Electricity

Power plants in California provided approximately 71 percent of the total electricity to satisfy in-state electricity demand in 2010 of which 15 percent came from renewable sources such as biomass, geothermal, small hydro, solar, and wind. The Pacific Northwest provided another 8.5 percent of the total electricity demand of which 31 percent came from renewable sources. The Southwestern U.S. provided 20.8 percent of the total electricity demand, with 11.1 percent coming from renewable sources. In total, 13.7 percent of the total in-state electricity demand for 2010 came from renewable sources (CEC, 2012a). Five of the state's largest power plants are located in the Basin (U.S. Energy Information Administration, 2012). The largest power plants in California are located in northern California. The Moss Landing Natural Gas Power Plant (net summer capacity 2,529 megawatts (MW)) is located in Monterey Bay in Monterey County and the Diablo Canyon Nuclear Plant (net summer capacity 2,240 MW) is located in Avila Beach in San Luis Obispo County. The third and fourth largest power plants in California are the San Onofre Nuclear Generating Station (SONGS) (net summer capacity 2,150 MW) in San Diego and the AES Alamitos Natural Gas Power Generating Station (net summer capacity 1,997 MW) in Long Beach in Los Angeles County. SONGS is operated by Southern California Edison International, San Diego Gas & Electric Company, and the City of Riverside Utilities Department. SONGS was shut down in January 2012 due to premature wear found in the tubes of its recently replaced steam generators. It has recently been reported (June 7, 2013) that it is not scheduled to re-open and will be permanently shutdown. The Los Angeles Department of Water and Power (LADWP) operates the state's fifth and sixth largest power plants: the Castaic Pump-Storage Power Plant[1] in Castaic (net summer capacity 1,620 MW) and Haynes Natural Gas Power Plant (net summer capacity 1,524MW) in Long Beach. The seventh and eighth largest power plants in California are outside of the Basin: the Ormond Beach Natural Gas Power Plant (net summer capacity 1,516 MW) in City and County of Oxnard and Pittsburg Natural Gas Power Plant (net summer capacity 1,311 MW) in the City of Pittsburg in Contra Costa County. The AES Redondo Beach Natural Gas Power Plant (net summer capacity 1,310 MW) in Redondo Beach is the ninth largest in the state (AES, 2010). The Helms Pumped Storage (net summer capacity 1,212 MW) in Sierra National Forest of Fresno County is the tenth largest power plant in the state.

Local electricity distribution service is provided to customers within southern California by one of two investor-owned utilities – either SCE or SDG&E – or by a publicly owned utility, such as the Los Angeles Department of Water and Power (LADWP) and the Imperial Irrigation District. SCE is the largest electric utility company in Southern California with a service area that covers all or nearly all of Orange, San Bernardino, and Ventura Counties, and most of Los Angeles and Riverside Counties. SCE delivers 78 percent of the retail electricity sales to residents and businesses in southern California. SDG&E provides local distribution service to the southern portion of Orange County (SCAG, 2012).

The LADWP is the largest of the publicly owned electric utilities in southern California. LADWP provides electricity service to the most of the customers located in the City of Los Angeles and provides approximately 20 percent of the total electricity demand in the Basin. The other publicly owned utilities in southern California include Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside, Vernon, and the Imperial Irrigation District (SCAG, 2012).

Table 3-8 shows the amount of electricity delivered to residential and nonresidential entities in the counties in the Basin.

[1] The Castaic Pump-Storage Power plant is operated by the LADWP in cooperation with the Department of Water Resources (DWR).

TABLE 3-8
2011 Electricity Use GWh (Aggregated, includes self generation and renewables)

Sector	Los Angeles	Orange	Riverside	San Bernardino	Total
Ag & Water Pump	1,453	1,600	623	483	4,159
Commercial	26,093	9,151	5,137	4,510	44,890
Industry	11,384	2,588	1,071	2,620	17,662
Mining	1,346	356	129	214	2,045
Residential	19,292	6,682	6,644	4,717	37,334
Streetlight	267	115	80	56	517
TCU	4,065	979	504	953	6,501
Total	63,899	21,470	14,188	13,553	113,109

Source: California Energy Commission –email sent by Steven Mac on August 24, 2012.

Natural Gas

Four regions supply California with natural gas. Three of them—the Southwestern U.S., the Rocky Mountains, and Canada—supplied 88 percent of all the natural gas consumed in California in 2010. The remainder is produced in California (CEC, 2012c).

Southern California Gas Company (SoCalGas), an investor-owned utility company, provides natural gas service throughout the district, except for the southern portion of Orange County, portions of San Bernardino County, and the City of Long Beach. The Long Beach Gas & Oil Department (LBGOD) is municipally owned and operated by the City of Long Beach, providing gas service for the cities of Long Beach and Signal Hill (LBGOD, 2012). San Diego Gas & Electric Company provides natural gas services to the southern portion of Orange County. In San Bernardino County, Southwest Gas Corporation provides natural gas services to Victorville, Big Bear, Barstow, and Needles (SCAG, 2012).

Table 3-9 provides the estimated use of natural gas in California by residential, commercial and industrial sectors. In 2010, about 50 percent of the natural gas consumed in California was for electric generation purposes (2,312 + 784/6,133).

TABLE 3-9
California Natural Gas Demand 2010
(Million Cubic Feet per Day – MMcf/d)

Sector	Utility	Non-Utility	Total
Residential	1,193	--	1,193
Commercial	493	--	493
Natural Gas Vehicles	33	--	33
Industrial	810	--	810
Electric Generation	1,856	456	2,312
Enhanced Oil Recovery (EOR) Steaming	30	784	814
Wholesale / International + Exchange	230	--	230
Company Use and Unaccounted-for	85	--	85
EOR Cogeneration / Industrial	--	164	164
Total	**4,729**	**1,403**	**6,134**

Source: California Gas Report, 2010

Renewable Energy

Renewable energy is energy that comes from sources that regenerate and can be sustained indefinitely, unlike fossil fuels, which are exhaustible. The five most common renewable sources are biomass, hydropower, geothermal, wind, and solar. Unlike fossil fuels, non-biomass renewable sources of energy do not directly emit greenhouse gasses.

The production and use of renewable fuels has grown quickly in recent years as a result of higher prices for oil, and a number of state and federal government incentives, including the Energy Policy Acts of 2002 and 2005. The use of renewable fuels is expected to continue to grow over the next 30 years, although projections show that reliance on non-renewable fuels to meet most energy needs will continue. In 2009, 11.6 percent of all electricity in California came from renewable resources such as wind, solar, geothermal, biomass and small hydroelectric facilities. Large hydro plants generated another 9.2 percent of our electricity. In 2011, consumption of renewable sources in the United States totaled about nine quadrillion British thermal units (Btu) or about nine percent of all energy used nationally. About 13 percent of U.S. electricity was generated from renewable sources in 2011 (U.S. EIA, 2012c).

The Renewables Portfolio Standard (RPS) requires investor-owned utilities, electric service providers, and community choice aggregators regulated by the CPUC to procure 33 percent of retail sales per year from eligible renewable sources by 2020. CPUC issues quarterly renewable energy progress report to the state Legislature, showing that the state's utilities have met the goal of serving 20 percent of their electricity with renewable energy and are already on track to far surpass that goal in 2012 (CEC, 2012n). The quarterly reports focus on California's three large investor-owned utilities: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). These investor-owned utilities currently provide approximately 68 percent of the state's electric retail sales and analyzing this data provides significant insight into the state's RPS progress. On March 1, 2012, the large investor-owned utilities reported in their 2012 RPS Procurement Progress Reports that they served 20.6 percent of their electricity with RPS-eligible generation in 2011. Table 3-10 shows the renewable electricity use in Los Angeles, Orange, Riverside and San Bernardino in 2011.

TABLE 3-10
2011 Renewable Electricity Use in GW

Sector	Los Angeles	Orange	Riverside	San Bernardino	Total
Ag & Water Pump	5	0	3	1	10
Commercial	127	32	48	44	252
Industry	10	3	0	3	16
Mining	7	0	1	0	8
Residential	77	32	37	20	166
Transportation, Communications and Utilities	51	0	4	12	68
Total	277	67	94	80	519

Source: California Energy Commission –email sent by Steven Mac on August 24, 2012.

Hydroelectric Power

Hydroelectric power, or hydropower, is generated when hydraulic turbines connected to electrical generators are turned by the force of flowing or falling water. In 2007, hydro-produced electricity used by California totaled nearly 43,625 GWh or 14.5 percent of the total system power. In-state production accounted for 69.5 percent of all hydroelectricity, while imports from other states totaled 30.5 percent (CEC, 2012e).

California has nearly 343 hydroelectric facilities with an installed capacity about 13,057 MW. Hydro facilities are broken down into two categories: larger than 30 MW capacity facilities are called "large hydro"; smaller than 30 MW capacity facilities are considered "small hydro" and are totaled into the renewable energy portfolio standards. The amount of hydroelectricity produced varies each year, largely dependent on rainfall. During the drought from 1986 to 1992, production fell to less than 22,400 GWh (CEC, 2012e), while total generation increased from 211,028 GWh to 245,535 GWh over the same period of time.

The larger hydro plants on dams in California (such as Shasta, Folsom, Oroville, etc.) are operated by the U.S. Bureau of Reclamation and the state's Department of Water Resources. Smaller plants are operated by utilities, mainly PG&E and Sacramento Municipal Utility District. Licensing of hydro plants is done by the Federal Energy Regulatory Commission with input from state and federal energy, environmental protection, fish and wildlife, and water quality agencies.

Wind Power

Wind power is the conversion of the kinetic energy of the wind into a useful form of energy. Wind can be harnessed by wind turbines, windmills, windpumps, or sails. These technologies use wind power for practical purposes such as generating electricity, grinding grain, pumping water, or propelling a boat.

A wind turbine works much like the propeller of an airplane. The blades of a turbine are tilted at an angle and contoured such that the movement of the air is channeled creating low and high pressures on the blade that force it to move. The blade is connected to a shaft, which in turn is connected to an electrical generator. The mechanical energy of the turning blades is changed into electricity.

California has several wind farms, a group of wind turbines in the same location used to produce electricity, strategically placed in windy areas, as one of the problems with using wind to generate power is that wind is not always constant.

Wind energy plays an integral role in California's electricity portfolio. In 2007, turbines in wind farms generated 6,802 GWh of electricity - about 2.3 percent of the state's gross system power. Additionally, hundreds of homes and farms are using smaller wind turbines to produce electricity (CEC, 2012h).

There are many windy areas in California. Problems with using wind to generate power are that it is not windy all year long nor is the wind speed constant. It is usually windier during the summer months when wind rushes inland from cooler areas, such as near the ocean, to replace hot rising air in California's warm central valleys and deserts. By placing wind turbines in these windy areas, California’s wind power supply variance can be minimized. Utility-scale wind power generation facilities can be found in Altamont Pass, Solano, Pacheco Pass, the Tehachapi Ranges, and San Gorgonio Pass.

Solar (Photovoltaic Cells)

Solar energy technologies produce electricity from the energy of the sun through photovoltaic (PV) cells, also known as solar cells. PV cells are electricity-producing devices made of semiconductor materials coming in many sizes and shapes, often connected together to ultimately form PV systems. When light shines on a PV cell, the energy of absorbed light transfers to electrons in the atoms of the PV cell semiconductor material causing electrons to escape from their normal positions in the atoms and become part of the electric flow, or current, in an electrical circuit. While small PV systems can provide electricity for homes, businesses, and remote power needs, larger PV systems provide much more electricity for contribution to the electric power system.

The PV cells for small systems can be purchased in two formats: 1) as a stand-alone module that is attached to the roof or on a separate system; or, 2) using integrated roofing materials with dual functions -- as a regular roofing shingle and as a solar cell making electricity.

California’s cumulative installed capacity of PV systems in 1998 was 6.3 MW. In 2008, the capacity of PV systems reached about 440 MW, producing 661.5 GWh of electricity for the state (CEC, 2012i).

Solar Thermal Energy

Solar thermal energy (STE) is the technology for converting the sun’s energy into thermal energy (heat) through solar thermal collectors. The U.S. EIA classifies solar thermal collectors into three categories:

- Low-temperature: Flat plate collectors are used to warm homes, buildings, and swimming pools.
- Medium-temperature: Flat plate collectors are used to heat water or air for residential and commercial uses.
- High-temperature: Mirrors or lenses are used to concentrate STE for electric power production.

Low and medium-temperature collectors can be further classified as either passive or active heating systems. In a passive system, air is circulated past a solar heat surface and through the building by convection (meaning that less dense warm air tends to rise while denser cool air moves downward). No mechanical equipment is needed for passive solar heating. Active heating systems require a collector to absorb and collect solar radiation. Fans or pumps are used to circulate the heated air or heat absorbing fluid. Active systems often include some type of energy storage system.

High-temperature systems used in solar thermal power plants use the sun's rays to heat a fluid to very high temperatures through the use of mirrors or lenses. The fluid is then circulated through pipes so it can transfer its heat to water to produce steam. The steam, in turn, is converted into mechanical energy in a turbine and into electricity by a conventional generator coupled to the turbine.

California has 11 of the 13 solar thermal power plants in the United States. These facilities are concentrated in the desert areas of the state in the Mojave area. Solar thermal plants produced 675 GWh in 2007, or 0.22 percent of the state's total electricity production (CEC, 2012i).

California's electric utility companies are required to use renewable energy to produce 20 percent of their power by 2010 and 33 percent by 2020 and a main source of the required renewable energy will be solar energy. Many large solar energy projects are being proposed in California's desert area on federal Bureau of Land Management (BLM) land. The developments of 34 large solar thermal power plants have been proposed with a planned combined capacity of 24,000 MW (CEC, 2012i).

Consumptive Uses

<u>Residential, Commercial, Industrial, and Other Uses</u>

Major energy consumption sectors (in addition to transportation) include residential, commercial, industrial uses as well as street lighting, mining, and agriculture. Unlike transportation, these sectors primarily consume electricity and natural gas. Total annual electricity consumption in the SCAG region is approximately 123,678 million kWh (39,432 kWh for residential uses and 84,246 kWh for nonresidential uses) (SCAG, 2008). The residential, commercial, and industrial sectors account for approximately 30, 39, and 19 percent, respectively, of total regional electricity consumption. The agriculture, mining and other uses account for another 14 percent (CEC, 2005).

Within the residential sector, lighting, small appliances, and refrigeration account for most (approximately 60 percent) of the electricity consumption, and within the industrial and commercial sector, lighting, motors, and air cooling account for most (approximately 65 percent) of the electricity consumption. Electricity use by households varies depending on the local climate and on the housing type (e.g., single-family vs. multi-family), as per the four distinct geographic zones in the SCAG region: the cooler and more temperate coastal zone; an inland valley zone; the California central valley zone, and the desert zone, where temperatures are more extreme.

Californians consumed approximately 12,774 million therms of natural gas per year in 2010 (CEC, 2012r). Approximately, 4,662 million therms of natural gas per year were consumed in Los Angeles, Orange, Riverside and San Bernardino Counties (CEC, 2012s). The California Energy Commission (CEC) expects residential natural gas use to increase by 1.3 percent per year and commercial natural gas use to increase by 1.8 percent per year. Industrial natural gas demand increased in 2010 over 2009. The most recent data from the CEC show that the residential sector uses the largest amount of natural gas, both across the state and in the SCAG region. Statewide, the industrial sector was second in the amount of natural gas consumed. The commercial sector falls behind residential, mining, and industrial uses in natural gas consumption in the SCAG region and statewide. The agricultural sector accounts for only one percent of the natural gas use statewide and in the SCAG region.

Consumption Reduction Efforts

There are various policies and initiatives to reduce energy consumption and increase the share of renewable energy generation and use in the region. These strategies include energy efficient building practices, smarter land use with access to public transportation, and participating in energy efficiency incentive programs. All publicly-owned utilities and most municipal-owned utilities that provide electric and natural gas service also administer energy conservation programs. These programs typically include home energy audits; incentives for replacement of existing appliances with new, energy-efficient models; provision of resources to inform businesses on development and operation of energy-efficient buildings; and construction of infrastructure to accommodate increased use of motor vehicles powered by natural gas or electricity (CEC, 2012s).

CHAPTER 4

ENVIRONMENTAL IMPACTS

INTRODUCTION

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2 (a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The discussion of environmental impacts may include, but is not limited to: the resources involved; physical changes; alterations of ecological systems; health and safety problems caused by physical changes; and, other aspects of the resource base, including water, scenic quality, and public services. If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible [CEQA Guidelines §15126.4].

The CEQA Guidelines indicate that the degree of specificity required in a CEQA document depends on the type of project being proposed [CEQA Guidelines §15146]. The detail of the environmental analysis for certain types of projects cannot be as great as for others. Accordingly, this Draft EA analyzes impacts on a regional level and impacts on the level of individual industries or individual facilities only where feasible.

The categories of environmental impacts to be studied in a CEQA document are established by CEQA [Public Resources Code, §21000 et seq.], and the CEQA Guidelines, as promulgated by the State of California Secretary of Resources. Under the CEQA Guidelines, there are approximately 17 environmental categories in which potential adverse impacts from a project are evaluated. The Initial Study evaluated the project against the environmental categories to determine those environmental categories that may be adversely affected by the proposed project are further analyzed in the appropriate CEQA document.

POTENTIAL ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES

Pursuant to CEQA, an Initial Study, including an environmental checklist, was prepared for this project (see Appendix B). Of the 17 potential environmental impact categories, two topics (air quality and energy) were identified as being potentially adversely affected by the proposed project for potential foregone air quality emission reductions and potential adverse reliability of the electrical supply system including lack of local generating capacity. Two comment letters were received on the Initial Study and those comment letters along with responses to the comments can be found in Appendix C.

The topics of air quality emissions and energy impacts are further evaluated in detail in this Draft EA. The environmental impact analysis for this environmental topic incorporates a "worst-case" approach. This approach entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method ensures that all potential effects of the proposed project are documented for the decision-makers and the public. Accordingly, the following analyses use a conservative "worst-case" approach for analyzing the potentially significant adverse environmental impacts associated with the implementation of the proposed project.

In order to assist in evaluating air quality and energy impacts from the proposed project, an economics professor and Director of the Program on Energy and Sustainable Development at

Stanford University, Dr. Frank Wolak, was hired to conduct an economic and electricity supply reliability analysis of the proposal to assess a fee to access the SCAQMD's offset bank. The report and Dr. Wolak's qualifications as an expert in the subject are provided in Appendix D.

AIR QUALITY AND GHG EMISSIONS

The initial evaluation in the NOP/IS (see Appendix B) identified the topic of air quality as potentially being adversely affected by the proposed project. The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. The proposed project is, therefore, consistent with the existing purposes of Regulation XIII to ensure that there are no net increases in emissions from new or modified permitted sources. However, the SCAQMD has received comments from stakeholders asserting that implementing fees pursuant to PR 1304.1 may deter investment in replacing 50+ year-old boilers with new more efficient gas turbines. As a result, a repowering project could be delayed, downsized or abandoned.

Significance Criteria

To determine whether air quality impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the following criteria. If impacts exceed any of the significance thresholds in Table 4-1, they will be considered significant. All feasible mitigation measures will be identified and implemented to reduce significant impacts to the maximum extent feasible. The proposed project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 4-1 are equaled or exceeded.

The SCAQMD makes significance determinations for construction impacts based on the maximum or peak daily emissions during the construction period, which provides a "worst-case" analysis of the construction emissions. Similarly, significance determinations for operational emissions are based on the maximum or peak daily allowable emissions during the operational phase.

Project-Specific Air Quality and GHG Emissions Impacts: Eligible EGFs that elect to access the SCAQMD's offset bank pursuant to a specific offset exemption in Rule 1304 (a)(2) [*Electric Utility Steam Boiler Replacement*] currently receive the offsets free of charge. The proposed project would charge a fee that may cause some EGFs to decide to delay, downsize or abandon repowering. In addition, existing boilers may need to increase usage if added electricity demand is necessary due to population and economic growth or cooling due to extreme weather conditions.

If a repowering project is delayed, impacts from the construction would not change as a result of the proposed project aside from the impacts occurring at a later date. Construction impacts would be reduced if the repower project was downsized or abandoned. Thus, no significant adverse construction impacts would be generated from the proposed project. The remaining analysis will focus on the air quality impacts from the operation of the proposed project.

TABLE 4-1
SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs), Odor, and GHG Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
GHG	10,000 MT/yr CO2eq for industrial facilities	
Ambient Air Quality Standards for Criteria Pollutants [d]		
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contribu to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)	
PM10 24-hour average annual average	 10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation) 1.0 $\mu g/m^3$	
PM2.5 24-hour average	 10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)	
SO2 1-hour average 24-hour average	 0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)	
Sulfate 24-hour average	 25 $\mu g/m^3$ (state)	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contribu to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)	
Lead 30-day Average Rolling 3-month average Quarterly average	 1.5 $\mu g/m^3$ (state) 0.15 $\mu g/m^3$ (federal) 1.5 $\mu g/m^3$ (federal)	

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day; ppm = parts per million; $\mu g/m^3$ = microgram per cubic meter; ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents; > = greater than

According to Dr. Wolak (see Appendix D, p.11-13), the decision to repower and when to repower can be expected from "whatever action yields the highest variable profits." This means an EGF will need to decide if maintaining the existing steam boiler yields more variable profit as compared to repowering with a cleaner more efficient unit. The analysis continues to note that "the major rationale for repowering an existing unit is to reduce the variable cost of producing energy by employing a more efficient technology." By employing more energy-efficient technology for producing energy, emissions per megawatt (MW) hour will be reduced. Using basic economic equations along with known input data, the analysis concludes that repowering would maximize the profits of the unit owner as opposed to the maintenance of the existing steam boiler units. See Appendix D for the detailed analysis and input data.

Dr. Wolak's analysis further explores the effect on the decision to repower when a fee is charged on the project. For the sake of a comparative analysis, the annual fee option is used for a repowering project, which is compared to the annual operation costs to maintain existing boilers. Using the example EGF provided in the Staff Report for PR 1304.1, the impact from the estimated of annual cost per MW is calculated, along with a higher fee (tripled from the proposed project). Both calculations concluded the decision to repower would be "largely unaffected by the presence of a substantial cost to access the SCAQMD offset bank." The analysis also calculates the effects of the annual fixed cost of maintaining the existing unit is zero, and still concludes that there would be no change to the decision to repower the unit.

Dr. Wolak's analysis also explains how the cost of the fee to access the SCAQMD's offset bank will be recovered through retail prices passed on to retail electricity consumers through CPUC-regulated prices and, similarly, for other load-serving entities in the California ISO control area. By being able to pass on the costs to retail electricity consumers in their retail prices, the burden of the cost to access the offsets from the SCAQMD internal bank is not borne solely by the EGF. For more detail regarding the recovery of fees by the electrical generation unit owners, refer to the report in Appendix D.

Finally, the report observes if the efficiency of the new unit is close to the efficiency of the existing unit, then the repowering may not be profitable. However, this circumstance affecting the decision of the unit owner exists currently without the proposed project. An additional fee could further exacerbate the decision to delay, downsize or abandon the project.

The report explains how the "load serving" EGFs under the authority of the California Public Utilities Commission (CPUC) and California Independent System's Operators (ISO) are part of the LA Basin Local Reliability area and will be required to meet the joint CPUC and California local RA requirements for this region according to California ISO's 2014 Local Capacity Technical Analysis[1] that plans for a reliable supply of electricity within the state. Because of the needs identified by ISO in the Technical Analysis and the recent decision by Southern California Edison to permanently shut down the San Onofre Nuclear Generating System (SONGS), virtually all of the generation capacity in the LA Basin Local Reliability Area will be required to meet the region's RA requirements. Therefore, it is highly unlikely that repowering projects will be downsized or abandoned entirely as there will be competitive pressure from other power producers to take advantage of the need to fulfill the region's energy needs. Based on the combination of regulatory requirements along with the economic drivers to repower (described above), the report concludes the proposed fee will not change the decision to repower for those "load serving" EGFs.

[1] http://www.caiso.com/Documents/Final2014LocalCapacityTechnicalStudyReportApr30_2013.pdf

Municipal utilities have expressed concern over the proposed fees as a potential burden, although the fees for those EGFs less than 100 MW are lower than EGFs producing greater than 100 MW. Dr. Wolak notes that "Although municipal utilities, such at the Los Angeles Department of Water and Power (LADWP), City of Glendale Water and Power (GWP), and Burbank Water and Power (BWP) are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and Long Term Procurement Plan (LTPP) process. Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts." (see Appendix D, p.9). However, this DEA treats as reasonably foreseeable the potential that one or more municipal utilities could potentially choose to delay repowering their equipment for reasons beyond those analyzed in Dr. Wolak's report. It should be noted that the decision to delay repowering as a result of the proposed project will not affect the reliability of the energy supply (see Energy section for further analysis and conclusions) as the existing steam boilers will continue to operate to meet the demand.

In order to estimate a potential delay in emission reductions from municipal utilities, there needs to be a comparison of emissions from the older steam boiler equipment to newer, cleaner, and more efficient equipment. EGFs taking advantage of the specific offset exemption under Rule 1304 (a)(2) would need to replace an existing steam boiler with a combined cycle gas turbine or other advanced gas turbine or renewables, such as solar, geothermal or wind. To ensure the analysis examines a "worst cast" scenario, it is assumed that an EGF delaying a repowering project would be replacing the steam boiler with either a simple cycle or a combined cycle gas turbine.

A gas turbine, also called a combustion turbine, is a type of internal combustion engine. It has an upstream rotating compressor connected to a downstream turbine. Fresh atmospheric air flows through a compressor that brings it to higher pressure. Ignited fuel generates a high-temperature flow so the high-pressure gas enters a turbine, where it rotates the shaft used to drive the compressor and other devices such as an electric generator that may be coupled to the shaft. The energy that is not used for shaft rotation comes out in the exhaust gases. A simple cycle gas turbine differs from a combined cycle machine in that it has no provision for waste heat recovery. In a combined cycle, the exhaust of one heat engine is used as the heat source for another so that more useful energy is extracted from the heat, thus increasing the system's overall efficiency.

There are many variations in the types of potential sources including the type of boilers, size of boilers, number of boilers to be repowered, operating capacity of the boiler, age of the boiler, etc. which could be affected. In order to resolve the variability, an emissions rate of pounds per MW is calculated for a steam boiler unit and compared to a cleaner more efficient gas turbine in accordance with the specific offset exemption in Rule 1304 (a)(2). It is assumed the turbines will be operated with natural gas (which is Best Available Control Technology (BACT)). The difference in emissions per MW is multiplied by the total amount of MW potentially affected by the proposed project to determine project impact.

To respond to the concern that the steam boilers could be operated at an increased load to handle future increased energy need, the boilers are assumed to be operating at 100 percent capacity on a peak daily basis. However, in reality, it is infeasible for boilers to operate at 100% capacity all the time. Although the annual average capacity utilization achieved by municipal utilities are substantially lower, for the purposes of this DEA we assume a full 100% utilization factor for the purpose of evaluating the "worst case scenario" if boiler replacement projects are delayed. Table 4-2 provides emissions from two boilers generating different MW (at 100 percent capacity) based on EPA's AP-42 emission factors (Table 1.4-2). The two boilers were chosen because they are typical sizes found at municipal utilities. It is assumed the boilers are controlled with selective catalytic reduction (SCR). By comparing the emissions from the replacement equipment with existing boilers operating at maximum capacity on a daily basis, the analysis includes impacts from boilers increasing their load in a "worst case" daily scenario. As seen in Table 4-2, the emission rates for the boilers are trending the same but for a "worst case" daily scenario, the emission rates from boiler #1 will be used for the comparative analysis as it yielded higher values.

The criteria pollutants affected by the proposed project and delay of emission reductions are particulate matter (PM10), volatile organic compounds (VOC), sulfur oxides (SOx) and nitrogen oxides (NOx). PR 1304.1 requires only non-RECLAIM sources to pay for NOx emissions, however the NOx emission factor for a steam boiler or gas turbine will not alter if the equipment is located at a RECLAIM or a non-RECLAIM facility. In addition, any potential air quality impact from the proposed rule is considered in a CEQA analysis.

TABLE 4-2
Steam Boiler Criteria Pollutant Emissions and Rate per MW

Pollutant	Emission Factor	Boiler #1 (at 44 MW)		Boiler #2 (at 55 MW)	
		Emissions (lbs/day)	Emission Rate (lbs/day/MW)	Emissions (lbs/day)	Emission Rate (lbs/day/MW)
PM10	7.6 lbs/mmcf	96.3	2.2	105.1	1.9
VOC	5.5 lbs/mmcf	68.7	1.6	763.0	1.4
SOx	0.6 lbs/mmcf	7.6	0.17	8.3	0.15
NOx	5 ppm	80.4	1.8	88.1	1.6

If an EGF takes advantage of the specific offset exemption under Rule 1304 (a)(2), an electric utility steam boiler would need to be replaced with a combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. A simple cycle gas turbine qualifies as the replaced equipment as long as it is intercooled or chemically-recuperated, etc. Table 4-3 examines the emissions from a single cycle gas turbine and combined cycle gas turbine that could be installed to replace the steam boiler in accordance with the specific offset exemption in Rule 1304 (a)(2). In order to calculate a "worst case" scenario, a most efficient combined cycle gas turbine generating 405 MWwas analyzed although that size would be unlikely to replace boilers generating 44-55 MW of power generation. It was assumed the gas turbine would be operating at 100% capacity. As shown in Table 4-3, the combined cycle gas turbine generates lower emissions per MW than the simple cycle gas turbine. Thus, for a "worst case" scenario, a high emitting steam boiler operating a 100% capacity is compared to the most efficient, lowest emitting per MW gas turbine (Table 4-4). The gas turbines are assumed to comply with BACT with usage of control technology such as a SCR/carbon monoxide catalyst. The NOx emissions from the simple cycle are higher because gas turbines operate at 15% oxygen (O2) while boilers operate at 3% O2. So, even though the emission factor (concentration) is lower in the turbine exhaust compared to the boiler, there is more exhaust out the turbine stack, so the mass emissions are more. This analysis does not consider the replacement of steam boilers with renewables (e.g., solar, wind, geothermal, etc.) since the current air quality permit projects subject to proposed Rule 1304.1 have not been submitted for renewable energy equipment, and there are no foreseeable projects that would substitute a steam boiler for a renewable project.

TABLE 4-3
Gas Turbine Criteria Pollutant Emissions and Rate per MW

Pollutant	**Simple Cycle** (at 49 MW)			**Combined Cycle** (at 405 MW)		
	Emission Factor	**Emissions** (lbs/day)	**Emission Rate** (lbs/day/MW)	**Emission Factor**	**Emissions** (lbs/day)	**Emission Rate** (lbs/day/MW)
PM10	7.0 lbs/mmcf	74.7	1.5	7.0 lbs/mmcf	248	0.61
VOC	2 ppm	30.5	0.62	2 ppm	126	0.31
SOx	0.6 lbs/mmcf	6.4	0.13	0.6 lbs/mmcf	45	0.11
NOx	2.5 ppm	109.7	2.24	2 ppm	444	1.10

California ISO has projected new generation needs between 2,900-4,615 MW[2], however that projection does not include the recent decision to permanently shutdown the San Onofre Nuclear Generating System (SONGS) that produces 1,600 MW of electricity. This projection includes both "load serving" EGFs and municipal utilities. As discussed earlier and concluded in Dr. Wolak's report, the proposed fee would not change the economics of a generation unit owner's decision to repower an existing steam boiler, particularly for those EGFs within the California ISO control area, and subject to the joint CPUC and California ISO RA process.

Potential repowering projects from municipal utilities, such as Glendale Water and Power[3] and Burbank Water and Power[4], could affect up to approximately 200 MW over the next 9 to 16 years. It should be noted that realistically, if all municipal utilities decide to delay repowering older boilers for whatever reason, emission reductions could be delayed incrementally and not all at once. As some projects are delayed, others will begin to be implemented as municipal short-term RA requirements and long-term planning processes are triggered. However, for a "worst case" scenario, it is assumed that all the 200 MW will be affected by the potential delay in repowering, thus resulting in a delay in potential emission reductions at a given time. As discussed earlier, the steam boiler equipment is assumed to be operating at 100 percent capacity to ensure potential "worst case" increased daily emissions are considered, which could also lead to substantially higher operational costs due to the higher heat rating of existing older boilers compared to new turbines. In reality, steam boilers typically operate at 10-30% capacity and rarely operate at 100% capacity, if at all.

[2] http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf

[3] "100 MW or less replacement projects undertaken by Burbank or Glendale" per April 22, 2013 Broiles & Timms, LLP comment letter

[4] "100 MW or less replacement projects undertaken by Burbank or Glendale" per April 22, 2013 Broiles & Timms, LLP comment letter

Table 4-4 provides a direct comparison between the emissions rate (pounds per MW) of steam boilers and cleaner more efficient equipment, which could occur if municipal utilities' repowering projects are delayed as a result of the proposed fee. The analysis compares the emission rate (in pounds of emission per MW) of steam boilers to both a simple cycle turbine and a combined cycle turbine. The higher emission rate difference (for a more "worst case" scenario) between the simple cycle and combined cycle turbine to the boiler is multiplied to the total amount of potentially affected MW and evaluated against the daily significance thresholds to determine significance.

TABLE 4-4
Potential Peak Daily Delay of Emission Reductions from PR 1304.1

Pollutant	**Boiler Emission Rate** (lbs/day/ MW)	**Simple Cycle**		**Combined Cycle**		**Potentially Affected MW**	**Potential Peak Delay in Emission Reductions**[3] (lbs/day)	**Operational Significance Threshold** (lbs/day)/ **Significant?**
		Emission Rate (lbs/day/ MW)	**Difference in Rate**[1] (lbs/day/ MW)	**Emission Rate** (lbs/day/ MW)	**Difference in Rate**[2] (lbs/day/ MW)			
PM10	2.2	1.5	0.7	0.61	1.59	200	**318**	150/Yes
VOC	1.6	0.62	0.98	0.31	1.29	200	**258**	55/Yes
SOx	0.17	0.13	0.04	0.11	0.06	200	12	150/No
NOx	1.8	2.24	(0.44)	1.10	0.7	200	**140**	55/Yes

1. Example calculation to determine difference in rate:
   Boiler emission rate (2.2 lbs/day/MW) – Simple cycle emission rate (1.5 lbs/day/MW) = 0.7 lbs/day/MW
2. Example calculation to determine difference in rate:
   Boiler emission rate (2.2 lbs/day/MW) – Combined cycle emission rate (0.61 lbs/day/MW) = 1.59 lbs/day/MW
3. Potential daily peak emissions calculated using the rate difference (lbs/MW) of combined cycle turbine (higher difference to the boiler) multiplied by total affected MW. Example: 1.59 lbs/day/MW x 200 MW = 318 lbs/day

As shown in Table 4-4, PM10, VOC and NOx emissions exceed the daily significance threshold as a result of a "worst case" scenario in which municipal utilities delay repowering projects and increase load from the boilers to 100%.

There are considerations with regards to the potential significance determination. First, it is highly unlikely all of the municipal utilities could decide to delay their repowering projects at the same time, as assumed in the analysis. Second, the "worst case" scenario of the boilers operating at 100% capacity and replacing with a high power generating combined cycle is not expected to realistically occur. Third, fees collected from other EGFs electing to use the 1304(a)(2) exemption will fund air quality improvement projects that will, in turn, create emissions reductions. These emission reductions gained will assist in counteracting the potential delay in emission reductions caused by delaying repowering projects. However, the amount of the emission reductions gained through air quality improvement projects is not known at this time. Fourth, as concluded in Dr. Wolak's report (see Appendix D), the length of the delay to repower old equipment is not infinite as there are short-term RA requirements and long-term municipal planning processes to ensure older equipment will not cause an inadequate supply of electricity. Finally, there will be an additional cost of natural gas to operate boilers are 100% capacity, which could result in high operating cost if not repowered, further incentivizing municipal utilities to repower.

In order to provide a more "real world" example, the difference in boiler and gas turbine emissions was provided by representatives for the cities of Burbank and Glendale[5]. Please refer to Appendix E for copies of the submitted comment letters and supplemental information provided to staff that outlines the parameters used to determine the emissions in these two "real world" scenarios.

Burbank Water and Power (BWP) operate two natural gas boilers generating 50 MW during peak times typically during the summer. A natural gas simple cycle turbine at 100 MW (LMS100) is assumed to replace the two boilers (at 50 MW each). The analysis assumes a "worst case" of running all three summer months (92 days, 2,208 hours) to account for a potential increased load of the boilers to handle any additional needed demand. Table 4-5 provides the daily emissions from the two boilers and simple cycle gas turbine, as well as a difference in emissions, which constitutes the potential delay in emission reductions if a repowering project is delayed due to the proposed project.

TABLE 4-5
Criteria Pollutant Emissions from Burbank Boilers and Future Simple Cycle Turbine

Pollutant	**Boilers** (at 50 MW each)			**Simple Cycle** (at 100 MW)			Potential BWP Delay in Emission Reduction (lbs/day)
	Emission Factor	**Emissions[1] per boiler** (lbs/year)	**Total Daily Emissions[2]** (lbs/day)	**Emission Factor**	**Emissions** (lbs/year)	**Daily Emissions** (lbs/day)	
PM10	7.6 lbs/mmcf	5,230	28.6	7.0 lbs/mmcf	1,730	4.7	**24**
VOC	5.5 lbs/mmcf	3,785	20.7	2 ppm	672	1.8	**19**
SOx	0.6 lbs/mmcf	413	2.3	0.6 lbs/mmcf	150	0.41	**2**
NOx	5 ppm	4,386	24	2.5 ppm	2,413	6.6	**17**

1. Based on total 688 mmcf derived from total 722,520 mmBTU divided by high heating value of 1050 BTU/cf
2. Example calculation: 5,230 lbs/year x 2 boilers / 365 days/year = 28.6 lbs/day

Table 4-6 provides the daily emissions from the natural gas and landfill gas boilers operated by Glendale Water and Power (GWP) and a 75 MW combined cycle gas turbine to replace the boilers, as well as a difference in emissions, which constitutes the potential delay in emission reductions if the repowering is delayed due to the PR 1304.1. The boilers are currently constrained by a NOx limit of 35 tons per year (70,000 pounds/year) pursuant to Rule 1135. Thus, the boiler emissions presented in Table 4-6 are based on a very conservative scenario or 100% allowable capacity. The combined cycle gas turbine replacing the boilers is anticipated to operate at 60% capacity. Please refer to Appendix E for copies of the submitted comment letters and supplemental information provided to staff that outlines the parameters used to determine the emissions.

[5] Broiles & Timms, LLP comment letters dated February 19, 2013 and February 22, 2013; and March 21, 2013 email.

TABLE 4-6

Criteria Pollutant Emissions from Glendale Boilers and Future Combined Cycle Turbine

Pollutant	**Boilers** (Natural Gas and Landfill Gas)			**Combined Cycle** (at 75 MW)			Potential GWP Delay in Emission Reduction (lbs/day)
	Emission Factor	Annual Emissions (lbs/year)	Total Daily Emissions[1] (lbs/day)	Emission Factor	Emissions (lbs/year)	Daily Emissions (lbs/day)	
PM10	7.6 lbs/mmcf	36,788	100.8	7.0 lbs/mmcf	22,177	60.8	**40**
VOC	5.5 lbs/mmcf	20,250	55.5	2 ppm	8,610	23.6	**32**
SOx	0.6 lbs/mmcf	5,695	15.6	0.6 lbs/mmcf	1,920	5.3	**10**
NOx	5 ppm	70,000	191.7	2.5 ppm	30,944	84.8	**107**

1. Example calculation: 36,788 lbs/year / 365 days/year = 100.8 lbs/day

Table 4-7 presents the overall total potential delay in emission reductions using the data provided for the cities of Burbank and Glendale. The "real world" operational impacts are much less than the "worst case" hypothetical scenario and conservative analysis for potential delay in emission reductions that concluded significance for three criteria pollutants (see Table 4-4). While showing a "real world" scenario does provide insight as to how extremely conservative the "worst case" scenario is, for the purposes of the CEQA analysis, the significance conclusions as to the potential impacts from the proposed project will remain the same as presented in Table 4-4.

TABLE 4-7

Potential Delay in Criteria Pollutant Emission Reductions from Municipal Utilities

Pollutant	Potential Delay in Emission Reduction (lbs/day)		TOTAL Potential Delay in Emission Reduction (lbs/day)	Operational Significance Threshold (lbs/day)
	BWP	GWP		
PM10	24	40	**64**	150
VOC	19	32	**51**	55
SOx	2	10	**12**	150
NOx	17	107	**124**	55

GHG emissions also have the potential for a delayed reduction if the repower projects are delayed or if the boilers are needed to be operated at a higher capacity. Unlike criteria pollutants whose impact is determined on a peak daily basis, the significance impact of GHG emissions, in the form of carbon dioxide equivalent (CO2e), are determined on an annual basis. The SCAQMD brightline significance threshold for GHG is 10,000 metric tons (MT) of CO2e per year. While boilers could operate 100 percent capacity on a daily basis, it is not mechanically feasible to assume the boiler would operate annually at such a high load. Typically, the boilers are operated at a 30% capacity on an annual basis (e.g., during summer months for peakers) based on historical activity data of boiler usage[6]. As a "worst case" scenario for consideration of a potential increased usage of the boilers, the maximum load on an average annual basis could be 60 percent capacity. It is staff's engineering opinion that boilers over 40 years old are unlikely to be able to support more than 60% capacity factor. Normal maintenance and repair will likely limit generation to a level below 60%. Therefore, this analysis is conservative. Table 4-8 provides the potential GHG emissions from two boilers generating different MWs and the emissions rate in emissions per MW to be comparative.

TABLE 4-8
Steam Boiler GHG Emissions and Rate per MW

GHG	**Emission Factor** (lbs/mmcf)	**Boiler #1** (at 44 MW)			**Boiler #2** (at 55 MW)		
		Emissions (lbs/day)	**Emissions*** (MT/yr)	**Emission Rate** (MT/yr/MW)	**Emissions** (lbs/day)	**Emissions*** (MT/yr)	**Emission Rate** (MT/yr/MW)
CO2e	120,276	1,523,897	151,697	3,447	1,662,214	165,465	3,008

*The conversion used is 2,200 lbs per MT, 365 days/year at 60 percent capacity

As shown in Table 4-8, the emission rates for the boilers are trending the same but for a "worst case" annual scenario, the emission rates from boiler #1 will be used for the comparative analysis as it yielded higher values. A substantial advantage in operating gas turbines is their ability to be turned on and off within minutes, supplying power during peak, or unscheduled, demand. Although it is not possible to predict the average annual operation of the gas turbines, for the sake of a more "worst case" scenario gas turbines are assumed to annually operate at 80% capacity. Table 4-9 examines the GHG emissions from both the simple cycle and combined cycle gas turbines. The emissions are converted to annual MT and divided by the MW at 80 percent capacity to derive a GHG emission rate.

TABLE 4-9
Gas Turbine GHG Emissions and Rate per MW

GHG	**Emission Factor** (lbs/mmcf)	**Simple Cycle** (at 49 MW)			**Combined Cycle** (at 405 MW)		
		Emissions (lbs/day)	**Emissions*** (MT/yr)	**Emission Rate** (MT/yr/MW)	**Emissions** (lbs/day)	**Emissions*** (MT/yr)	**Emission Rate** (MT/yr/MW)
CO2e	120,276	1,283,345	170,334	3,476	6,927,898	919,520	2,270

*The conversion used is 2,200 lbs per MT, 365 days/year at 80 percent capacity

Both emission rates for simple cycle and combined cycle gas turbines are compared to the boiler emission rates for GHG emissions per MW and provided in Table 4-10. The potential annual delay in GHG emission reductions is compared to the GHG significant threshold to determine significance.

[6] Communication with SCAQMD engineering staff June 2013 who derived their data from US EPA's Air Markets Program Data (http://ampd.epa.gov/ampd)

TABLE 4-10
Potential Annual Delay of GHG Emission Reductions from PR 1304.1

GHG	Boiler Emission Rate (MT/yr/MW)	Simple Cycle		Combined Cycle		Potentially Affected MW	Potential Annual Delay in Emission Reductions* (MT/yr)	GHG Significance Threshold (MT/yr)/ Significant?
		Emission Rate (MT/yr/MW)	Difference in Rate (MT/yr/MW)	Emission Rate (MT/yr/MW)	Difference in Rate (MT/yr/MW)			
CO2e	3,447	3,476	(29)	2,270	1,177	200	**235,400**	10,000/Yes

* The combined cycle was used to determine the potential annual delay in emission reductions because it has the greater difference in rate compared to the boiler.

As shown in Table 4-10, the potential delay in GHG emission reductions could exceed the annual GHG significance threshold. However, it is unlikely that all projects will be delayed at the same time and it is anticipated that the delay will be temporary as there are short-term RA requirements and long-term municipal planning processes in place to ensure that failing older equipment will not lead to electricity shortfalls. Also, fees collected from other EGFs electing to use the 1304(a)(2) exemption will fund air quality improvement projects that will, in turn, create emissions reductions and will have co-benefits in reducing GHG emissions.

For the power plants in the cities of Burbank and Glendale, the GHG emissions were also calculated for a "real world" scenario using data was provided by their representatives that can be found in Appendix E. Table 4-11 provides the CO2e emissions from the Burbank boilers and future simple cycle gas turbine, and the Glendale boilers and combined cycle gas turbine. The difference between the emissions is determined and also provided in Table 4-11. The difference would be the potential delay in GHG emission reductions if a repowering project is delayed. The "real world" annual delay exceeds the GHG significance threshold but slightly less than the "worst case" scenario. The potential GHG impact from the proposed project would remain significant.

TABLE 4-11
Potential Annual Delay of GHG Emission Reductions from Municipal Utilities

GHG	Emission Factor (lbs/mmcf)	Burbank			Glendale			Potential Annual Delay in Emission Reductions (MT/yr)
		Boiler Emissions (MT/yr)	Simple Cycle Emissions (MT/yr)	Difference in Emissions (MT/yr)	Boiler Emissions[1] (MT/yr)	Combined Cycle Emissions[2] (MT/yr)	Difference in Emissions (MT/yr)	
CO2e	120,276	75,064	13,718	61,346	68,339	236,520	168,181	**229,527**

1. Based on 1,250 mmcf and 2,200 lbs per MT;
   Example calculation: 1,250 mmcf/year x 120,276 lbs/mmcf / 2,200 lbs/MT = 68,339 MT/year
2. Based on 5,256 annual hours as presented in the assumption calculations in Appendix E (Glendale spreadsheet).

Table 4-12 outlines the typical toxic air contaminants (TACs) resulting from the operation of a boiler and natural gas turbine. Except for two, all the contaminants are the same from either equipment type. The TACs listed are those with potential cancer effects to provide a more "worst case" toxic analysis. Table 4-12 also lists the emissions factors associated with those TACs for boilers and gas turbines and daily toxic emissions based on the same operating parameters as the boilers and gas turbines analyzed above. As noted earlier, gas turbines typically possess control technology such as oxidation catalysts that control up to 90 percent of

VOC emissions, which in turn reduce toxic emissions. Such reductions are included in the emissions table.

TABLE 4-12
Toxic Air Contaminants from Boiler and Gas Turbine

TAC	CAS No.	Boiler (>100 MMBTU/hr)		Gas Turbine	
		Emission Factor (lbs/mmcf)	**Emissions** (lbs/day)	**Emission Factor** (lbs/mmcf)	**Emissions** (lbs/day)
Formaldehyde	50-000	0.0036	0.0468	0.7242	0.7749
Ethyl Benzene	100-414	0.0020	0.0260	0.03264	0.0349
Benzene	71-432	0.0017	0.0221	0.01224	0.0131
Acetaldehyde	75-070	0.0009	0.0117	0.04080	0.0437
Propylene Oxide	75-569	---	0.0000	0.02958	0.0317
Napthalene	91-203	0.0003	0.0039	0.00133	0.0014
PAHs (excluding Napthalene)	1-150	0.0001	0.0013	0.00092	0.0010
1,3 butadiene	106-990	---	0.0000	0.00044	0.0005

By generating equivalent emissions, the toxics could be added for comparison. Equivalent emissions are calculated by weighting the emissions of the carcinogenic pollutants by the ratio of their cancer potency to the cancer potency of a driver TAC. In this analysis, the driver is formaldehyde. Thus, emissions from species less potent than formaldehyde are weighted less, while emissions from species more potent than formaldehyde are weighted more. As a result, formaldehyde has a weighting factor of one and the others more or less than one. The weighting factor is then multiplied by the emissions listed in Table 4-12 to determine formaldehyde equivalent toxic emissions. In doing so, the emissions are additive. Table 4-13 lists the carcinogens, their inhalation cancer potencies, weighting factors and resulting emissions. Finally the emissions are added for total resulting toxic impact from each equipment type.

TABLE 4-13
Weighted Toxic Emissions

TAC	Inhalation Cancer Potency $(mg/kg\text{-}d)^{-1}$	Weighting Factor	Boiler (>100 MMBTU/hr)	Gas Turbine
			Emissions (lbs/day)	**Emissions** (lbs/day)
Formaldehyde	0.021	1.00	0.0468	0.7749
Ethyl Benzene	0.0087	0.41	0.0108	0.0145
Benzene	0.1	4.76	0.1052	0.0624
Acetaldehyde	0.01	0.48	0.0056	0.0208
Propylene Oxide	0.013	0.62	0.0000	0.0196
Napthalene	0.12	5.71	0.0223	0.0081
PAHs (excluding Napthalene)	3.9	185.71	0.2414	0.1828
1,3 butadiene	0.6	28.57	0.0000	0.0135
TOTAL EMISSIONS (lbs/day)			**0.4321**	**1.0965**

The difference in equivalent toxic emissions between the operation of the boiler and gas turbine is less than one pound per day. As such, the potential adverse toxic impact from delaying a repowering project or increasing the use of the boiler is anticipated to be not significant.

Project-Specific Mitigation for Air Quality and GHG Emissions Impacts: As concluded above, the air quality analysis for the proposed project indicates that PM10, VOC, NOx and GHG emission reductions foregone during operation could exceed the applicable significance thresholds and are concluded to be significant. If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the impacts of the proposed project. PR 1304.1 is a fee rule and alternatives to the project are adjustments to the fee, which are addressed in the alternatives analysis found in Chapter 5. The potential adverse air quality and GHG emissions impacts from the proposed project will be the result of those EGFs deciding to delay projects to repower to cleaner, more efficient equipment because of the fee. Aside from the existing regulatory framework, such as deadlines to cease using once-through-cooling, or pre-arranged agreements, there is no requirement regarding the timing of these facilities to repower. In addition, the SCAQMD cannot regulate when and how the projects are built. However, the proposed project charges a fee to those facilities that are conferred the benefit of obtaining offsets from the SCAQMD internal bank pursuant to Rule 1304 (a)(2) offset exemption. This fee will fund air quality improvement projects, such as those found in the 2012 AQMP.

Emission reductions efforts outlined in the AQMP include a number of measures designed to address combustion emissions that will result in a GHG emission reduction co-benefit. Examples of the types of projects were identified by the 2012 AQMP and analyzed in Chapter 4 of the Final Program EIR. Such projects could include mobile source implementation measures such as replacing on-road and off-road vehicles with natural gas, hybrid-electric, or all-electric vehicles; accelerated retirement of older vehicles; as well as installation of infill photovoltaic systems. The California Air Resources Board (CARB) prepared a planning document along with the SCAQMD and San Joaquin Valley Air Pollution Control District called "Vision for Clean Air: A Framework for Air Quality and Climate Planning[7]" that took a coordinated look at strategies needed to meet California's multiple air quality and climate goals well into the future. In examining the most efficient use of limited resources and the time needed to develop cleaner technologies, the document concluded a transition to zero- and near-zero emission technologies are necessary to meet both AQMP air quality standards and GHG climate goals.

By funding these projects, emission reductions will be generated that provide a regional air quality and GHG benefit to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay their repower projects because of the fee. It is possible that the use of these fees will fully offset the adverse air quality impact but this cannot be guaranteed at this time. For these reasons, there are no further feasible mitigation measures that would reduce or eliminate the expected delay in emission reductions. Consequently, the operational air quality and GHG emissions impacts from the proposed project cannot be mitigated to less than significant. In addition, Findings and a Statement of Overriding Considerations will be prepared for the Governing Board's consideration and approval prior to the public hearings for the proposed amendments.

[7] http://www.arb.ca.gov/planning/vision/vision.htm

Remaining Air Quality and GHG Emissions Impacts: The fees collected from issuing offsets from the SCAQMD offset bank via Rule 1304 (a)(2) will be used to fund air quality improvement projects as provided in the 2012 AQMP, thus assisting to reach the goals of the 2012 AQMP. Such projects could include mobile source implementation measures such as replacing on-road and off-road vehicles with natural gas, hybrid-electric, or all-electric vehicles; accelerated retirement of older vehicles; as well as installation of infill photovoltaic systems. The potential adverse air quality and GHG emissions impacts from implementing such control measures in the 2012 AQMP have been analyzed in the Final Program Environmental Impact Report (EIR) for the 2012 AQMP (http://www.aqmd.gov/ceqa/documents/2012/aqmd/finalEA/2012AQMP/2012aqmp_fpeir.html). The specific impacts analysis can be found in Chapter 4 of the Final Program EIR.

Cumulative Air Quality and GHG Emissions Impacts: The preceding project-specific analysis concluded that air quality and GHG emissions impacts during operation could be significant from implementing the proposed project. Specifically, PM10, VOC, NOx and GHG emission reductions foregone could exceed the SCAQMD's significance threshold for operation. Thus, the air quality and GHG emissions impacts during operation are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1).

Even though the proposed project could result in significant adverse project-specific emission reductions foregone during operation, they are not expected to interfere with the air quality progress and attainment demonstration projected in the 2012 AQMP. The reason for this conclusion is that ultimately the repower projects will take place and Rule 1304.1 is expected to generate funds to reduce or offset PM10, VOC and NOx emissions from a delay in repowering. Further, based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules with future compliance dates, is anticipated to bring the district into attainment with all national and most state ambient air quality standards by the year 2014 for the federal 24-hour PM2.5 standard and by the year 2023 for the federal eight-hour ozone standard. Therefore, cumulative operational air quality impacts from the proposed project, previous amendments and all other AQMP control measures considered together, are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that cumulative air quality and GHG emissions impacts from all AQMP control measures are not expected to be significant (SCAQMD, 2012). Therefore, there would be no significant adverse cumulative adverse operational air quality and GHG emissions impacts from implementing the proposed project.

Cumulative Mitigation Measures: The analysis indicates that the proposed project could result in a delay of PM10, VOC, NOx and GHG emission reductions during operation of the proposed project, but the delay would not result in permanent adverse significant cumulative air quality and GHG emissions impacts because of existing backstop measures and regulatory requirements along with AQMP control measures considered together. Thus, no cumulative air quality and GHG emissions mitigation measures for operation are required.

ENERGY

The initial evaluation in the NOP/IS (see Appendix B) identified the topic of energy as potentially being adversely affected by the proposed project. The SCAQMD has received comments from stakeholders asserting that implementing fees pursuant to PR 1304.1 may deter investment in replacing 50+ year-old boilers with new more efficient gas turbines or other more efficient gas turbines, etc. As a result local and basin-wide electrical system reliability could be adversely impacted.

Significance Criteria

To determine whether energy impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the following criteria:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Conflicts with Adopted Energy Conservation Plans or Standards; Wasteful and/or Inefficient Use of Non-renewable Resources: Affected facilities would still be expected to comply with any existing energy conservation standards, to the extent that affected equipment is subject to energy conservation standards. It is not expected that the proposed project will affect in any way or interfere with that affected EGF's ability to comply with its energy conservation plan or energy standards. Further, it is expected that the installation and operation of any equipment used will also comply with all applicable existing energy standards. Thus, project construction and operation activities will not utilize non-renewable energy resources in a wasteful or inefficient manner.

Substantial Depletion of Existing Energy Resource Supplies and Increased Utility Demand: The intent of the proposed project is to continue to allow EGFs eligible for the specific offset exemption pursuant to Rule 1304 (a)(2) to access the SCAQMD internal bank if they elect to do so, but for eligible facilities to pay for the offset in order to recoup the market value as a reasonable cost of conferring the benefit. The proposed project could result in some facilities delaying the repowering of old equipment but would not delay to the point of providing an inadequate supply. Thus, the proposed project will not deplete existing energy resource supplies or increase utility demand. One commenter noted "increasing loads (e.g., switching to electric vehicles and higher cooling demands associated with climate change) will require increasing amounts of local generating capacity." Although this potential increase is independent of the proposed project, the concern was that the proposed fee will deter investment to repower to more efficient equipment that could handle the increased load. As a result, the existing steam boilers could need to increase capacity to accommodate the increased load. From an energy perspective, the increased need will be met either with the existing steam boilers or the new more efficient equipment. The potential adverse air quality impacts from increasing the use of steam boilers was evaluated in the air quality section of this chapter.

With regard to overall energy reliability, the analysis prepared by Dr. Frank Wolak, an economics professor at Stanford University and former chair of the Market Surveillance Committee at California ISO, states that there are "many more than adequate safeguards in place to ensure that grid reliability will not be adversely impacted by this decision" (PR 1304.1). The report concludes that "because of the combined CPUC and California ISO RA process, the

CPUC LTPP process, and several other state and local policies, Proposed Rule 1304.1 is unlikely to have any discernible impact on the reliability of the supply of electricity." (Appendix D, p.1). See the complete report in Appendix D, which thoroughly analyzes the reliability impacts of the proposed project.

As outlined in Dr. Wolak's analysis, CPUC and ISO ensure that there is adequate generation capacity within the state to meet future electricity demand. Specifically, the California Public Utility Code Section 380 is a formalized regulatory mechanism designed to maintain a reliable supply of electricity in California. Section 380 is reproduced in Appendix D following the report. For those municipalities that are autonomous and outside of CPUC and ISO's jurisdiction, they have similar, local long-term planning and resource adequacy policies. "Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts." (Appendix D, p.9)

Further, because EGFs will be able to recover the cost of the fees through retail rates, the costs of the proposed project are not borne solely by the EGFs and the likelihood that an EGF will delay a repowering project is diminished. Specifically, "a portion of the cost of the fee to access the District's offset bank will likely be recovered from the prices load-serving entities in Southern California pay for local RA capacity." (Appendix D, p.15) Additionally, the California ISO tariff has a provision allowing an EGF to pay the EGF's annual total cost of operating and then pass these costs on to electricity consumers for those EGFs that are required to remain in the District and operate because of the ISO's local reliability requirements. The report concludes that "the cost of this fee will be recovered from both the market-based and regulated services that suppliers in the District provide including local RA capacity, long-term contracts for energy, ancillary services, and regulated reliability services." (Appendix D, p.16) Moreover, municipalities that are outside of CPUC and ISO's jurisdiction have the autonomy to pass costs on to their consumers directly in retail rates. For a complete discussion of all of the mechanisms available to pass costs on to consumers, see Appendix D, p. 9, 15-16.

Based on the above findings, the energy impacts from the implementation of the proposed project are expected to be less than significant because the proposed project will not significantly adversely affect reliability of energy supplies, energy demand, or cause a depletion of energy sources.

Project-Specific Mitigation for Energy Impacts: No significant adverse impacts on energy are expected from the proposed project; therefore, no mitigation measures are required.

Cumulative Energy Impacts: No significant adverse project-specific reliability in energy supplies is expected, so energy impacts are not considered to be cumulatively considered as defined in CEQA Guideline §15064(h)(l). Therefore, cumulative energy impacts are concluded to be less than significant. Where a lead agency is examining a project with an incremental effect that is not cumulatively considerable, a lead agency need not consider the effect significant, but must briefly describe the basis for concluding that the incremental effect is not cumulatively considerable. Therefore the project's contribution to energy impacts is not cumulatively considerable and thus not significant. This conclusion is consistent with CEQA Guidelines §15064 (h)(4), which states, "The mere existence of cumulative impacts caused by other projects alone shall not constitute substantial evidence that the proposed project's incremental effects are cumulatively considerable”. Therefore, the proposed project is not expected to result in significant adverse cumulative energy impacts.

Cumulative Mitigation Measures: The analysis indicates that the proposed project would not result in an adverse significant cumulative energy impacts. Thus, no cumulative energy mitigation measures are required.

POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

While all the environmental topics required to be analyzed under CEQA were reviewed in the NOP/IS to determine if the proposed project could create significant impacts, the screening analysis concluded that the following environmental areas would not be significantly adversely affected by the proposed project: aesthetics, agriculture and forestry resources, biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, solid/hazardous waste, and transportation/traffic. Please refer to the NOP/IS in Appendix B for the detailed analysis and conclusions for the environmental topic impacts found to be not significant and not further analyzed.

SIGNIFICANT IRREVERSIBLE ENVIRONMENTAL CHANGES

CEQA Guidelines §15126 (c) requires an environmental analysis to consider "any significant irreversible environmental changes which would be involved if the proposed action should be implemented." This EA identified the topic of air quality during operation as the only environmental area potentially adversely affected by the proposed project.

Even though the proposed project could result in emission reductions foregone during operation that exceeds the applicable operational air quality significance threshold, they could for the following reasons not be expected to interfere with the air quality progress and attainment demonstration projected in the AQMP. Based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the district into attainment with all national and most state ambient air quality standards by the year 2023. Therefore, cumulative operational air quality impacts from the proposed project, previous amendments and all other AQMP control measures considered together, are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that direct cumulative air quality impacts from all AQMP control measures are not expected to be significant (SCAQMD, 2012). For these aforementioned reasons, the proposed project would not result in irreversible environmental changes or irretrievable commitment of resources.

POTENTIAL GROWTH-INDUCING IMPACTS

CEQA Guidelines §15126(d) requires an environmental analysis to consider the "growth inducing impact of the proposed action." Implementing the proposed project will not, by itself, have any direct or indirect growth-inducing impacts on businesses in the SCAQMD's jurisdiction because it is not expected to foster economic or population growth or the construction of additional housing and primarily affects existing facilities.

CONSISTENCY

CEQA Guidelines §15125(d) requires an EIR to discuss any inconsistencies between a proposed project and any applicable general plans or regional plans. SCAG and the SCAQMD have developed, with input from representatives of local government, the industry community, public health agencies, the USEPA - Region IX and CARB, guidance on how to assess consistency within the existing general development planning process in the Basin. Pursuant to the development and adoption of its Regional Comprehensive Plan Guide (RCPG), SCAG has developed an Intergovernmental Review Procedures Handbook (June 1, 1995). The SCAQMD also adopted criteria for assessing consistency with regional plans and the AQMP in its CEQA Air Quality Handbook. The following sections address the consistency between the proposed project and relevant regional plans pursuant to the SCAG Handbook and SCAQMD Handbook.

Consistency with Regional Comprehensive Plan and Guide (RCPG) Policies

The RCPG provides the primary reference for SCAG’s project review activity. The RCPG serves as a regional framework for decision making for the growth and change that is anticipated during the next 20 years and beyond. The Growth Management Chapter (GMC) of the RCPG contains population, housing, and jobs forecasts, which are adopted by SCAG’s Regional Council and that reflect local plans and policies, shall be used by SCAG in all phases of implementation and review. It states that the overall goals for the region are to: 1) re-invigorate the region’s economy; 2) avoid social and economic inequities and the geographical isolation of communities; and, 3) maintain the region’s quality of life.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Standard of Living

The Growth Management goals are to develop urban forms that enable individuals to spend less income on housing cost, that minimize public and private development costs, and that enable firms to be more competitive, strengthen the regional strategic goal to stimulate the regional economy. The proposed project in relation to the GMC would not interfere with the achievement of such goals, nor would it interfere with any powers exercised by local land use agencies. Further, the proposed project will not interfere with efforts to minimize red tape and expedite the permitting process to maintain economic vitality and competitiveness.

Consistency with Growth Management Chapter (GMC) to Provide Social, Political and Cultural Equity

The Growth Management goals to develop urban forms that avoid economic and social polarization promotes the regional strategic goals of minimizing social and geographic disparities and of reaching equity among all segments of society. Consistent with the Growth Management goals, local jurisdictions, employers and service agencies should provide adequate training and retraining of workers, and prepare the labor force to meet the challenges of the regional economy. Growth Management goals also includes encouraging employment development in job-poor localities through support of labor force retraining programs and other economic development measures. Local jurisdictions and other service providers are responsible to develop sustainable communities and provide, equally to all members of society, accessible and effective services such as: public education, housing, health care, social services, recreational facilities, law enforcement, and fire protection. Implementing the proposed project has no effect on and, therefore, is not expected to interfere with the goals of providing social, political and cultural equity.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Quality of Life

The Growth Management goals also include attaining mobility and clean air goals and developing urban forms that enhance quality of life, accommodate a diversity of life styles, preserve open space and natural resources, are aesthetically pleasing, preserve the character of communities, and enhance the regional strategic goal of maintaining the regional quality of life. The RCPG encourages planned development in locations least likely to cause environmental impacts, as well as supports the protection of vital resources such as wetlands, groundwater recharge areas, woodlands, production lands, and land containing unique and endangered plants and animals. While encouraging the implementation of measures aimed at the preservation and protection of recorded and unrecorded cultural resources and archaeological sites, the plan discourages development in areas with steep slopes, high fire, flood and seismic hazards, unless complying with special design requirements. Finally, the plan encourages mitigation measures that reduce noise in certain locations, measures aimed at preservation of biological and ecological resources, measures that could reduce exposure to seismic hazards, minimize earthquake damage, and develop emergency response and recovery plans. The proposed project has no impact on any of these issues except air quality. However, since the project would not interfere with the AQMP, it will not be inconsistent with the goal of improving the regional quality of life. Therefore, in relation to the GMC, the proposed project is not expected to interfere, but rather with attaining and maintaining the air quality portion of these goals.

Consistency with Regional Mobility Element (RMP) and Congestion Management Plan (CMP)

PR 1304.1 is consistent with the RMP and CMP since no significant adverse impact to transportation/circulation would result from specific equipment that are currently subject to permit requirements to be either exempt from permitting requirements or placed into a filing program. Because EGFs are not expected to increase their handling capacities, there would not be an increase in material transport trips associated with the implementation of PR 1304.1. Therefore, PR 1304.1 are not expected to significantly adversely affect circulation patterns or congestion management.

CHAPTER 5

ALTERNATIVES

INTRODUCTION

This Draft EA provides a discussion of alternatives to the proposed project as required by CEQA. A range of reasonable alternatives to the proposed project shall include measures that feasibly attain most of the project objectives and provide a means for evaluating the comparative merits of each alternative. A 'no project' alternative must also be evaluated. The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. CEQA Guidelines §15126.6 (c) specifically notes that the range of alternatives required in a CEQA document is governed by a 'rule of reason' and only necessitates that the CEQA document set forth those alternatives necessary to permit a reasoned choice. The key issue is whether the selection and discussion of alternatives fosters informed decision making and meaningful public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. SCAQMD Rule 110 (the rule which implements the SCAQMD's certified regulatory program) does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an EIR under CEQA.

PROJECT OBJECTIVES

As noted in Chapter 2, CEQA Guidelines §15124(b) requires the project description to include a statement of objectives sought by the proposed project, including the underlying purpose of the proposed project. Compatibility with project objectives is one criterion for selecting a range of reasonable project alternatives and provides a standard against which to measure project alternatives. The project objectives identified in the following bullet points have been developed: 1) in compliance with CEQA Guidelines §15124 (b); and, 2) to be consistent with policy objectives of the SCAQMD's New Source Review program. The project objectives are as follows:

- Recoup the fair market value of offsets provided to eligible EGFs from SCAQMD's internal offset bank pursuant to offset exemption Rule 1304 (a)(2) ~~that is a reasonable cost for conferring the benefit~~;
- Facilitate the continued development of a reliable electric grid within the SCAQMD's jurisdiction while discouraging electric generation not necessary to serve native load or reliability needs.
- Reduce the depletion rate of offsets from SCAQMD's internal offset bank to ensure the continued availability of offsets for essential public services; and,
- ~~Utilize funds~~ Maximize the availability of funds for investment in air pollution reduction projects ~~furthering~~ that further the goals outlined in the 2012 AQMP.

ALTERNATIVES SUMMARY

The proposed project and four alternatives to the proposed project are summarized in Table 5-1: Alternative A (No Project), Alternative B (Higher Fee), Alternative C (Higher Fee for Capacity Relocation Projects) and Alternative D (Lower Fee). Pursuant to CEQA Guidelines §15126.6 (b), the purpose of an alternatives analysis is to reduce or avoid potentially significant adverse effects that a project may have on the environment. The environmental topic areas identified in the NOP/IS that may be adversely affected by the proposed project were air quality and energy impacts. A comprehensive analysis of potential air quality, greenhouse gas (GHG), and energy impacts are included in Chapter 4 of this document. This chapter provides a comparison of the potential air quality, GHG, and energy impacts from each of the project alternatives relative to the proposed project, which are summarized in Table 5-2. That analysis concluded that only air quality/GHG impacts have the potential to be significant. Aside from air quality, no other significant adverse impacts were identified for the proposed project or any of the project alternatives. As indicated in the following discussions, the proposed project is considered to provide the best balance between meeting the objectives of the project while minimizing potentially significant adverse environmental impacts.

TABLE 5-1
Summary of PR1304.1 and Project Alternatives

Project	Project Description
Proposed Project	Requires electric generating facilities (EGFs) that elect to use the specific offset exemption under Rule 1304 (a)(2) to pay a fee for the amount of offsets provided from the SCAQMD internal accounts. The fee can be paid annually or one time up-front, and will be used to recoup the fair market value of offsets procured by eligible EGFs electing to use the offsets to comply with Rule 1304 (a)(2). The fee proceeds will be invested in air pollution improvement projects consistent with the 2012 AQMP.
Alternative A (No Project)	EGFs that use the specific offset exemption under Rule 1304 (a)(2) will continue to not pay for the amount of offsets provided from the SCAQMD internal accounts. The value of the offsets will not be recouped and there will be no investment in air pollution improvement projects.
Alternative B (Higher Fee)	Requires EGFs that use the specific offset exemption under Rule 1304 (a)(2) to pay a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable.
Alternative C (Higher Fee for Capacity Relocation)	Requires EGFs that are relocating electrical generation capacity from one facility to another facility for new equipment will be subject to a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable.
Alternative D (Lower Fee)	Requires EGFs that use the specific offset exemption under Rule 1304 (a)(2) to pay a lower fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. All other requirements and conditions in the proposed project would be applicable. The total value of the offsets will not be recouped and there will be a lower amount for investment in air pollution improvement projects.

TABLE 5-2
Comparison of Adverse Environmental Impacts of the Alternatives

Category	Proposed Project	Alternative A: No Project	Alternative B: Higher Fee	Alternative C: Higher Fee for Capacity Relocation Projects	Alternative D: Lower Fee
Air Quality Impacts – Criteria Pollutants	318 lbs PM10, 258 lbs VOC, and 140 lbs NOx daily delay in emission reductions and potential increase in usage of boilers; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering; also, no further emission reductions.	More significant than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more significant than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	Yes	No	Yes	Yes	Yes
Air Quality Impacts – GHG	235,400 MT/yr annual delay in emission reductions and potential increase in usage of boilers; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering; also, no further emission reductions.	More significant than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more significant than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	Yes	No	Yes	Yes	Yes
Air Quality Impacts – Toxics	Less than 1 lb per day daily delay in emission reductions; emission reductions from air quality improvement projects.	Less significant than proposed project due to no delay in emission reductions from repowering; also, no further emission reductions.	More potential adverse impact than proposed project; more emission reductions from air quality improvement projects than proposed project.	Slightly more potential adverse impact than proposed project; slightly more emission reductions from air quality improvement projects than proposed project.	Less significant than proposed project; less emission reductions from air quality improvement projects than proposed project.
Significant?	No	No	No	No	No
Operational Energy Impacts	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system	Reliability of electricity system
Significant?	No	No	No	No	No

ALTERNATIVES REJECTED AS INFEASIBLE

A CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and explain the reasons underlying the lead agency's determination (CEQA Guidelines §15126.6(c)). While the scope and goals of proposed projects may be relatively specific, a variety of options can be considered as alternatives to the proposed project. The following alternatives have been eliminated from further detailed consideration in the EA for the following reasons: 1) they fail to meet the most basic project objectives, 2) they are infeasible as defined by CEQA (CEQA Guidelines §15364), or 3) they are unable to avoid significant impacts (CEQA Guidelines §15126.6(c)).

Remove Offset Exemption for Electric Utility Steam Boiler Replacement

This potential alternative would eliminate the modeling and offset exemption for electric utility steam boiler replacement currently provided in Rule 1304(a)(2). The offsets required for these projects are currently obtained from the SCAQMD internal accounts for no charge. The exemption is applicable to those EGFs replacing an onsite steam boiler with a combined cycle gas turbine, other advanced gas turbines or renewable energy generation such as solar, geothermal or wind. The equipment must not exceed the basinwide electricity generating capacity per utility based on maximum electrical megawatt power rating. As such, the exemption also applies to EGFs relocating its electricity generating capacity to another location.

This alternative would eliminate the modeling and offset exemption for EGFs currently eligible under Rule 1304(a)(2) restricting access to free offsets from the SCAQMD internal accounts. As a result, affected EGFs would need to seek offsets from privately held credits at market value cost to meet their emissions offset obligations.

This alternative has been eliminated from consideration because it does not meet the basic project objectives to recoup the market value of offsets used for the EGF projects, reduce depletion of offsets from the internal bank, invest in air pollution investment projects, or further the goals of the AQMP. Furthermore, having to seek offsets in the open market could delay the project in replacing higher polluting steam boiler with cleaner alternatives, thus, have a delay in emission reductions similar to the proposed project. Thus, the alternative does not avoid potentially significant air quality impacts. In addition, the implementation of the alternative would require separate rulemaking to amend Rule 1304 and eliminate subsection (a)(2). Since this action is not proposed at this time, this alternative will not be further considered.

Modify the Applicable Fee Rates

The proposed rule requires EGFs obtaining offsets from the SCAQMD to pay either an annual fee or a onetime up-front for each pollutant emitted (PM, NOx, SOx, and VOC). A fee rate is applied to facilities with a repowered capacity of up to 100 MW and a different higher fee rate is applied to facilities with a repowered capacity of greater than 100 MW, for those MW in excess of 100.

This alternative would modify the applicable fee rates by lowering the repowering capacity of the lower fee rates up to 50 MW and the higher fee rate applying to those greater than 50 MW.

For those facilities under 50 MW, it is likely a facility offset exemption pursuant to Rule 1304(d) applies. The exemption is eligible to those new or modified facilities that demonstrate less than 4 tons/year of NOx emissions to be exempt from Rule 1303 (b)(2) requiring emission offsets. As such, an alternative providing relief for those under 50 MW is not necessary as the existing facility offset exemption would be available. In doing so, more facilities would be subject to the higher fee rate. Further, the effort to secure additional funds to pay the higher fee rate could delay the project in replacing higher polluting steam boiler with cleaner alternatives, thus, resulting in a delay in emission reductions similar to the proposed project. Therefore, the alternative does not avoid potentially significant air quality impacts. Based on these reasons, this alternative will not be further considered.

DESCRIPTION OF PROJECT ALTERNATIVES

The project alternatives described in the following subsections were developed by modifying specific components of the proposed project. The rationale for selecting and modifying specific components of the proposed project to generate feasible alternatives for the analysis is based on CEQA's requirement to present "realistic" and “potentially feasible” alternatives; that is, alternatives that can actually be implemented. When considering approval of the proposed project, the SCAQMD’s Governing Board may choose all of or portions of any of the alternatives analyzed, as well as variations on the alternatives, since the comparative merits of the project alternatives have been analyzed and circulated for public review and comment along with the analysis of the proposed project. The main components of the proposed project and each project alternative are summarized in Table 5-3. A complete description of the proposed project can be found in Chapter 2 (Project Description) and any element of the proposed project not listed will remain the same for Alternatives B, C and D.

TABLE 5-3
Comparison of Key Components of the Proposed Project to the Alternatives

Proposed Project (Key Components)	**Alternative A:** No Project	**Alternative B:** Higher Fee	**Alternative C:** Higher Fee for Capacity Relocation Projects	**Alternative D:** Lower Fee
EGFs pay fee to obtain offsets from SCAQMD internal accounts if eligible under Rule 1304 (a)(2) exemption	EGFs do not pay fee to obtain offsets from SCAQMD internal accounts if eligible under Rule 1304 (a)(2) exemption	EGFs pay a fee higher than proposed project to obtain offsets from SCAQMD internal accounts if eligible under Rule 1304 (a)(2) exemption	EGFs relocating capacity pay a fee higher than proposed project to obtain offsets from SCAQMD internal accounts if eligible under Rule 1304 (a)(2) exemption	EGFs pay a fee lower than proposed project to obtain offsets from SCAQMD internal accounts if eligible under Rule 1304 (a)(2) exemption
EGFs shall pay either an annual fee or single up-front fee for each pollutant	No fee is required	Same as proposed project	Same as proposed project	Same as proposed project

TABLE 5-3 (Concluded)
Comparison of Key Components of the Proposed Project to the Alternatives

Proposed Project (Key Components)	**Alternative A:** No Project	**Alternative B:** Higher Fee	**Alternative C:** Higher Fee for Capacity Relocation Projects	**Alternative D:** Lower Fee
Separate fee structure for projects of less than 100 MW and projects greater than 100 MW	No fee structure is necessary since no fee is required	Same as proposed project	Same as proposed project	Same as proposed project
Fee proceeds invested in air pollution improvement projects	No fee is required so no investment in air pollution improvement projects	Same as proposed project	Same as proposed project	Same as proposed project

Alternative A - No Project

CEQA Guidelines §15126.6 requires evaluation of a no project alternative to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project. The No Project Alternative assumes that the proposed project or Alternatives B, C and D would be adopted.

Alternative A or 'no project' means that the current requirements and conditions to obtain offsets from the SCAQMD internal accounts pursuant to Rule 1304 (a)(2) would be maintained. As such, EGFs that use the specific offset exemption under Rule 1304 (a)(2) will continue to not pay for the amount of offsets provided from the SCAQMD internal accounts.

Alternative B – Higher Fee

Alternative B is similar to the proposed project in all aspects except that Alternative B requires EGFs that elect to use the specific offset exemption under Rule 1304 (a)(2) to pay a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. While the fee rates will be modified with this alternative, the fee structure (e.g., up front lump sum or annual payment, MW size applicability, etc.) will remain the same as the proposed project. Therefore, those facilities generating less than 100 MW will pay a higher fee than currently proposed in PR1304.1 and those facilities generating greater than 100 MW will pay an even higher fee if electing to use the specific offset exemption under Rule 1304 (a)(2). The intent of this alternative is to ensure the value of the offset is reasonably recouped in order to appropriately compensate investment in air pollution improvement projects to further the goals of the Air Quality Management Plan (AQMP). Such projects could include mobile source implementation measures such as accelerating zero and near-zero emission vehicles into the market and accelerated retirement of older vehicles. Compared to the proposed project and Alternative A, there would be more funding for emission reduction projects with Alternative B, but the potential for delaying repowering projects would be equal or greater than the proposed project.

Alternative C – Higher Fee for Capacity Relocation Projects

The offset exemption under Rule 1304 (a)(2) allows access to the credits in the SCAQMD internal accounts for those facilities replacing steam boilers with a combined cycle gas turbine, other advanced gas turbines, or renewable energy generation such as solar, geothermal or wind. It requires the equipment must not exceed the basinwide electricity generating capacity per utility based on maximum electrical megawatt power rating. As such, the exemption also applies to an EGF relocating its electricity generating capacity to another location.

The proposed project affects facilities eligible for the specific offset exemption under Rule 1304 (a)(2) through either a repowering at the facility or transferring electrical generation capacity for new equipment at another facility. Alternative C would require EGFs that are relocating electrical generation capacity from another facility for new equipment be subject to a higher fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. The reason for this alternative is to provide more funding for emission reduction projects since the capacity relocation projects expose people near the new location to EGF emissions that were not being emitting from that location previously. All other requirements and conditions, such as the different fee structure based on MW generation, in the proposed project would be applicable. The number of sources affected by a higher fee under Alternative C is expected to be less than Alternative B, so the fees collected are expected to be less than those collected under Alternative B but more than under the proposed project.

Alternative D – Lower Fee

Alternative D is similar to the proposed project in all aspects except that Alternative D requires EGFs that use the specific offset exemption under Rule 1304 (a)(2) to pay a lower fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts. The intent of this alternative is to reduce the charge to the applicable EGFs for the proposed repower projects while still recouping the partial cost of the offset in order to help provide investment in air pollution improvement projects to further the goals of the AQMP. Such projects could include mobile source implementation measures such as accelerating zero and near-zero emission vehicles into the market and accelerated retirement of older vehicles.

COMPARISON OF THE ALTERNATIVES

The following section describes the potential adverse operational air quality and energy impacts that may be generated by each project alternative compared to the proposed project. A summary of the adverse operational air quality and energy impacts for the proposed project and each project alternative are also provided in Table 5-2.

AIR QUALITY AND GHG EMISSIONS

Alternative A - No Project

Unlike the proposed project, it is not anticipated that Alternative A would generate significant adverse air quality impacts during operation because electric generating facilities currently eligible for the offset exemption under Rule 1304 (a)(2) would continue to not pay a fee for the offsets from the SCAQMD internal accounts so they are not likely to delay, downsize or abandon the replacement of older higher emitting boilers with cleaner alternative equipment, as a result of the cost of the offsets. However, by not adopting the proposed project, no fees would be collected to compensate for the emissions reductions earned by the offset credit from the SCAQMD internal account. Consequently, if projects are not delayed under Alternative A, emission reductions would be achieved that would otherwise be foregone temporarily under the proposed project. Emissions reductions achieved based on increased boiler usage avoided could be 318 pounds per day of PM10, 258 pounds per day of VOC, 140 pounds per day of NOx and 235,400 MT per year of CO2e. The air quality and GHG emissions impacts from Alternative A would be deemed not significant. However, Alternative A would not fulfill three out of four objectives of the project as listed earlier in this chapter. Alternative A will not recoup the value of the offsets currently provided for free, would not maximize the availability of funds for investment and, thus, would not provide additional criteria pollutant and corresponding GHG emission reductions from air pollution improvement projects. Since these reductions are unknown at this time, they are not considered in the comparison of the alternatives. In addition, because the offsets are provided for free under Alternative A, it would not reduce the depletion rate of offsets from SCAQMD's internal offset bank.

Alternative B – Higher Fee

With a fee higher than the proposed project charged to EGFs electing to use the offset exemption under Rule 1304 (a)(2), more emissions reductions could be achieved by air pollution improvement projects as well as ensure the fair market value for the offsets are recouped. However, similar to the proposed project, a higher fee could cause EGFs to delay or downsize the replacement of older boilers, PM10, VOC, NOx and GHG emission reductions could be foregone. This delay is expected to be temporary since EGFs would not let the equipment breakdown to the point of potential blackouts in the region because current short-term RA requirements and LTPP planning processes would not allow for an inadequate supply of energy (*see Dr. Wolak's report in Appendix D and energy analysis in Chapter 4*). Since the fee is higher in Alternative B than the proposed project, affected EGFs could wait longer to repower than if subject to the proposed project, however, the daily foregone emissions would be the same as the proposed project. In addition, with higher fees, more emission reductions could be achieved with more air pollution improvement projects as compared to the proposed project or the No Project Alternative.

The universe of affected facilities under Alternative B could be the same or slightly more than the proposed project, so the delay of emissions reduction including a potential increase in boiler usage of 318 pounds per day of PM10, 258 pounds per day of VOC, 140 pounds per day of NOx and 235,400 MT per year of CO2e from the proposed project is expected to be the same or more under Alternative B. It is not possible to predict how many more affected facilities would be influenced by the higher fee to delay the repowering or increase usage of boilers. However, the air quality impacts from the proposed project are significant so the Alternative B air quality impacts would also be significant. The primary difference between Alternative B and the proposed project is that with a higher fee affected facilities might need to delay longer to allow for more time to acquire funding. Although not quantifiable at this time, Alternative B will also provide more emission reductions from air quality improvement projects due to more funding than achieved by the proposed project. Similar to the proposed project, the potential adverse air quality and GHG emissions impacts from Alternative B would be deemed significant.

Alternative B fulfills three of the four objectives to the project. With a higher fee, Alternative B recoups the fair market value of the offsets provided to eligible EGFs from the SCAQMD's internal offset bank, reduces the depletion rate of offsets, and maximizes the availability of funds for investment in air pollution reduction projects. Compared to the proposed project, Alternative B ensures recouping market value of the offsets, further reduces depletion of offsets, and provides more availability of funds. However, Alternative B generates more secondary adverse air quality and GHG emissions impacts from potentially further delaying repowering to cleaner equipment and has the potential to not facilitate continued development of a reliable electric grid as a result of the higher fee.

Alternative C – Higher Fee for Capacity Relocation Projects

Alternative C would charge a fee higher than the proposed project on certain EGFs eligible for the offset exemption under Rule 1304 (a)(2). The affected EGFs under Alternative C would be those relocating electrical generation capacity to another facility for new equipment but still eligible for the offsets from the SCAQMD internal accounts. Similar to Alternative B, with higher fees charged, these EGFs could also delay the relocation of the capacity and the installation of cleaner alternative equipment. However, the daily emission reductions foregone are expected to be less than Alternative B because a fewer number of EGFs would be affected by the higher fees charged by Alternative C. However, because it is not possible to predict the future decisions from EGFs, the affected universe could be equal or less than those affected under Alternative B.

Since the universe of affected sources under Alternative C is expected to be equal or lower than Alternative B, the delay in emission reductions based on a potential increase in boiler usage has the potential to be equal to or lower than 318 pounds per day of PM10, 258 pounds per day of VOC, 140 pounds per day of NOx and 235,400 MT per year of CO2e. Similar to Alternative B, the primary difference from the proposed project is that affected facilities could delay longer to accrue the necessary funds to comply with the proposed project.

If the affected universe of EGFs is smaller than those affected under Alternative B, less fees will be collected to recoup the value of the offsets provided by the SCAQMD internal accounts compared to Alternative B but more funding than achieved under the proposed project. As a result, more emission reductions will be achieved from the air pollution improvement projects compared to the proposed project (or No Project) but less than achieved with Alternative B. The potential adverse air quality and GHG emissions impacts from Alternative C would be deemed significant but less than Alternative B and slightly more significant than the proposed project.

Similar to Alternative B, Alternative C fulfills three of the four objectives to the project. With a higher fee for EGFs relocating capacity, Alternative C recoups the fair market value of the offsets provided to eligible EGFs from the SCAQMD's internal offset bank, reduces the depletion rate of offsets, and maximizes the availability of funds for investment in air pollution reduction projects. While Alternative C does not maximize the availability of funds as much as Alternative B, it should collect equal or more funds than the proposed project. Alternative C could generate potentially adverse secondary air quality and GHG emissions impacts for a longer time compared to the proposed project but not as long as Alternative B. Like Alternative B, Alternative C has the potential to not facilitate continued development of a reliable electric grid as a result of the higher fee for EGFs with relocated capacity.

Alternative D – Lower Fee

With a fee lower than the proposed project charged on EGFs eligible for the offset exemption under Rule 1304 (a)(2), less emission reductions could be achieved by air pollution improvement projects and less certainty the fair market value for the offsets is recouped. However, because a lower fee could cause less number of EGFs to delay the replacement of older boilers, a delay in emission reductions could be less than the proposed project, Alternative B or C, so less than 318 pounds per day of PM10, 258 pounds per day of VOC, 140 pounds per day of NOx and 235,400 MT per year of CO2e. Any potential delay caused by this alternative is expected to be temporary since EGFs would not allow the equipment to breakdown to the point of potential blackouts in the region because current short-term RA requirements and LTPP planning processes would not allow for an inadequate supply of energy (*see Dr. Wolak's report in Appendix D and energy analysis in Chapter 4*). Since the fee is lower in Alternative D than the proposed project and Alternative B and C, affected EGFs could potentially reduce the waiting time than if subject to the proposed project, therefore, reducing any daily foregone emissions compared to the proposed project. However, with lower fees, less emission reductions could be achieved with fewer air pollution improvement projects than compared to the proposed project and Alternative B and C. The potential adverse air quality and GHG emissions impacts from Alternative D would still be deemed significant as some emission reduction delay or increase boiler usage could occur, but less significant than the proposed project, and Alternative B and C.

Alternative D fulfills three out of the four objectives to the project but not to a level achieved by the proposed project or Alternatives B and C. With a lower fee, Alternative D is expected to facilitate the continued development of a reliable electric grid and assist in reducing the depletion rate of offsets from SCAQMD's internal offset bank. While Alternative D will generate funds for investment in air pollution reduction projects, it will fail in maximize the availability of funds because of the lower fee. Thus, subsequent emission reductions from the air pollution improvement projects will be less than achieved with the proposed project, Alternatives B or C. Compared to the proposed project, Alternative D could reduce the length of the potential delay in implementing repowering project by charging a lower fee. However, unlike Alternative D, the proposed project fulfills all four of the objectives.

ENERGY

Alternative A - No Project

Alternative A would continue to not charge a fee for those offsets obtained from the SCAQMD internal accounts under Rule 1304 (a)(2). Thus, energy reliability at the affected EGF and energy efficiency from cleaner alternative equipment such as combine cycle gas turbines and renewable will not be adversely affected by Alternative A.

<u>Alternative B – Higher Fee</u>

A higher fee on affected EGFs could cause a delay in the replacement or increase in usage of the older boiler equipment with cleaner alternative equipment, however EGFs are still expected to provide the electricity demand to their customers even if generated using older equipment. With regards to the equipment breakdown, current short-term RA requirements and LTPP processes would not allow for an inadequate supply of energy, so energy reliability is not anticipated to be affected (*see Dr. Wolak's report in Appendix D and energy analysis in Chapter 4*).

<u>Alternative C – Higher Fee for Capacity Relocation Projects</u>

Similar to Alternative B, a higher fee on certain EGFs could cause a delay in the replacement or increase in usage of the older boiler equipment with cleaner alternative equipment, however EGFs are still expected to provide the electricity demand to their customers even if generated using older equipment. With regards to the equipment breakdown, current short-term RA requirements and LTPP processes would not allow for an inadequate supply of energy, so energy reliability is not anticipated to be affected (*see Dr. Wolak's report in Appendix D and energy analysis in Chapter 4*).

<u>Alternative D – Lower Fee</u>

A lower fee on affected EGFs could cause a potential reduced delay in the replacement or increase in usage of the older boiler equipment with cleaner alternative equipment, but less than the proposed project, Alternatives B or C. However, EGFs are still expected to provide the electricity demand to their customers even if generated using older equipment. With regards to the equipment breakdown, current short-term RA requirements and LTPP processes would not allow for an inadequate supply of energy, so energy reliability is not anticipated to be affected (*see Dr. Wolak's report in Appendix D and energy analysis in Chapter 4*).

LOWEST TOXIC AND ENVIRONMENTALLY SUPERIOR ALTERNATIVES

In accordance with SCAQMD's policy document Environmental Justice Program Enhancements for FY 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

Implementing Alternative A means that there would be no emission reductions foregone and the corresponding health benefits that result from the emission reductions would occur compared to the proposed project and Alternatives B, C and D. Thus, Alternative A is considered to be the environmentally superior alternative. However, Alternative A would not fulfill three out of four objectives of the project as listed earlier in this chapter. Alternative A will not recoup the value of the offsets provided for free, not maximize the availability of funds for investment and, thus, would not provide additional criteria pollutant and corresponding GHG emission reductions from air pollution improvement projects. However, these reductions are unknown at this time, so to compare the benefits will not be possible. In addition, because the offsets are provided for free under Alternative A, it would not reduce the depletion rate of offsets from SCAQMD's internal offset bank.

If the "no project" alternative is determined to be the environmentally superior alternative, then the CEQA document shall identify an environmentally superior alternative among the other alternatives (CEQA Guidelines §15126.6 (e)(2)). Of the remaining alternatives evaluated, Alternative D is considered to be the environmentally superior alternative because it would charge the lowest fee that would likely delay less projects than Alternatives B and C. As a result, Alternative D would generate the lowest level of operational emission reductions foregone. However, Alternative D would also accrue the least amount of funding for air quality improvement programs. Since the air quality benefits from the implementation of these air quality improvement programs are not quantifiable at this time, no credit is being taken for these improvements.

CONCLUSION

By not adopting the proposed project, Alternative A would not delay the operational emission reductions or cause a possible increase in usage from replacing equipment in accordance with Rule 1304 (a)(2). However, Alternative A would not achieve three of the project objectives for the proposed project because Alternative A will not recoup the value of the offsets provided for free, not maximize the availability of funds for investment and would not reduce the depletion rate of offsets from SCAQMD's internal offset bank.

The proposed project will fulfill all four of the objectives of the project and, while generating potential secondary adverse air quality and GHG emissions impacts, the impacts might not last as long if Alternative B or C is chosen. By not maximizing the availability of funds for investment in air pollution reduction projects that further the goals outlined in the 2012 AQMP, Alternative D does not achieve all the objectives. Thus, when comparing the environmental effects of the project alternatives with the proposed project and evaluating the effectiveness of achieving the project objectives of the proposed project versus the project alternatives, the proposed project provides the best balance in achieving the project objectives while minimizing the adverse environmental impacts to air quality and GHG emissions and energy.

APPENDIX A

PROPOSED RULE 1304.1

The following version of Proposed Rule 1304.1 was distributed with the Draft EA on July 9, 2013. The final version of the rule to be considered for approval at the September 6, 2013 Governing Board meeting can be found in the Final Public Hearing Package.

PROPOSED RULE 1304.1. ELECTRICAL GENERATING FACILITY ~~ANNUAL~~ FEE FOR USE OF OFFSET EXEMPTION

(a) Purpose and Applicability

The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay ~~annual~~ fees for up to the full amount of offsets provided by the AQMD. Offsets in AQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304(a)(2). The ~~annual~~ fees will be invested in air pollution improvement strategies for the pollutants for which the fee is paid, or their precursors or criteria pollutants to which they contribute, consistent with the needs of the Air Quality Management Plan. This rule applies to all EGFs that use the offset exemptions described in Rule 1304(a)(2). Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use~~ing~~ Rule 1304(a)(2) and receiving the applicable permit to construct on or after ~~March~~ July 1, 2013.

(b) Definitions

(1) ELECTRICAL GENERATING FACILITY (EGF) means a facility that generates electricity for distribution in the state grid system, regardless of whether it also generates electricity for its own use or for use pursuant to a contract.

(2) COMMENCMENT OF OPERATION means to have begun the first fire of the unit(s), or to generate electricity for sale, including the sale of test generation.

(c) Requirements

(l) Any EGF operator ~~using~~ electing to use the offset exemptions provided by Rule 1304(a)(2) shall pay a fee, the Offset Fee (F_i), calculated pursuant to paragraph (c)(2), for each pound per day of each pollutant (i), for which the AQMD provides offsets. This fee may be paid on an annual basis or as a single payment at the election of the applicant.

(2) The ~~Annual~~ Offset Fee (F_i), for a specific pollutant (i), shall be calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate (R_i) or Single Payment Offset Fee Rate (L_i) and Offset Factor in Table A1 or A2, as applicable, by the fraction of the potential to emit level(s) of the new replacement unit(s) (PTErep~~$_{irep}$~~), which is calculated as the product of the potential to emit of the new replacement unit ($PTErep_i$) multiplied by the new replacement to existing unit generation ratio which is defined as the maximum permitted annual megawatt hour ~~rated capacity~~ (MWh) generation ~~(MW)~~ of the new replacement unit(s) (C_{rep}) minus the most recent twenty-four (24) months average of the ~~capacity factor~~megawatt hour (MWh) generation (megawatt utilization) of the unit(s) to be replaced ($C_{2YRAvgExisiting}$) divided by the maximum permitted annual ~~rated capacity~~ megawatt hour (MWh) generation of the new replacement unit(s) (C_{rep}), in accordance with the following equations:

Annual Payment Option

Repowering **the first 100MW** at a facility subsequent to ~~June~~July -1, 2013:

$$\textbf{Annual } Payment\ Offset\ Fee\ (F_i) = \boldsymbol{R_{iA1}} \times PTE\boldsymbol{rep}_{\cancel{irep}} \times OF_i \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Repowering **more than 100MW** cumulatively at a facility subsequent to July 1, 2013:

$$\textbf{Annual } Payment\ Offset\ Fee\ (F_i) = \left(\left[\boldsymbol{R_{iA1}} \times \left(\frac{100}{MW}\right)\right] + \left[\boldsymbol{R_{iA2}} \times \left(\frac{MW-100}{MW}\right)\right]\right) \times OF_i \times PTE\boldsymbol{rep}_{\cancel{irep}} \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Single Payment Option

Repowering **the first 100MW** at a facility subsequent to ~~June~~July 1, 2013:

$$\textbf{Single } Payment\ Offset\ Fee\ (F_i) = \boldsymbol{L_{iA1}} \times PTE\boldsymbol{rep}_{\cancel{irep}} \times OF_i \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Repowering **more than 100MW** cumulatively at a facility subsequent to July 1, 2013:

$$Annual\ Payment\ Offset\ Fee\ (F_i) = \left(\left[L_{iA1} \times \left(\frac{100}{MW}\right)\right] + \left[L_{iA2} \times \left(\frac{MW-100}{MW}\right)\right]\right) \times OF_i \times PTErep_{\cancel{irep}} \times \left(\frac{C_{rep}-C_{2YRAvgExisting}}{C_{rep}}\right)$$

Where;

F_i	=	~~Annual~~ Offset Fee for pollutant (i).
R_{iA1}	=	Table A1, Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually.~~, (see Table A applicable for rates).~~
R_{iA2}	=	Table A2, Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, annually.
L_{iA1}	=	Table A1, Single Payment Offset Fee Rate for pollutant (i), in terms of dollars per pound per day.
L_{iA2}	=	Table A2, Single Payment Offset Fee Rate for pollutant (i), in terms of dollars per pound per day.
MW	=	MW rating of new replacement unit(s).
PTE_{rep}	=	permitted potential to emit of new replacement unit(s) for pollutant i, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days).
OF_i	=	offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors,
		(see Table A1 or A2, as applicable, for ~~applicable~~ factors).
C_{rep}	=	maximum permitted annual megawatt hour ~~capacity (MWs)~~ (MWh) generation of the new replacement unit(s). (Maximum rated capacity (MW) x Maximum permitted annual operating hours (h)).

$C_{2YRAvgExisting}$ = the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced ~~averaged over~~ using the last twenty-four (24) month period immediately prior to submittal of the ~~complete applications for~~ permit to construct.

Table A1: Pollutant Specific Offset Fee Rates & Offset Factors applicable to the first 100MWs repowered at an EGF after ~~March~~ July 1, 2013 with offsets debited from the AQMD internal accounts[1]

Pollutant (i)	**Annual** Offset Fee Rate (R_{iA1}) ($per lb/day)*	**Single Payment** Offset Fee Rate (L_{iA1}) ($ per lb/day)	Offset Factor (OF_i)
PM	$1,993	$49,822	1.0
NOx**	$1,332	$33,286	1.2
SOx	$1,585	$39,631	1.0
VOC	$93	$2,318	1.2

*Offset Fees paid annually and adjusted annually by the CPI, consistent with the provisions of Rule 320

**For non-RECLAIM sources only

[1] Proposed revision to Annual and Single Payment Offset Fee Rates under consideration.

Table A2: Pollutant Specific ~~Annual Lease~~ Offset Fee Rates ~~(R_i)~~ & Offset Factors ~~(OF_i)~~ applicable to the balance of > 100MWs repowered at an EGF after ~~March~~ July 1, 2013 with offsets debited from the AQMD internal offset accounts[2]

~~Pollutant (i)~~	~~Annual Lease Fee (R_i) (Dollars per Pound per Day)*~~	~~Offset Factor (OF)~~
~~PM~~	~~$7,245~~	~~1.0~~
~~NOx**~~	~~$2,653~~	~~1.2~~
~~SOx~~	~~$2,434~~	~~1.0~~
~~VOC~~	~~$436~~	~~1.2~~

Pollutant (i)	**Annual** Offset Fee Rate (**R_{iA2}**) ($per lb/day)*	**Single Payment** Offset Fee Rate (**L_{iA2}**) ($ per lb/day)	Offset Factor (OF_i)
PM	$3,986	$99,643	1.0
NOx**	$2,663	$66,571	1.2
SOx	$3,170	$79,262	1.0
VOC	$185	$4,635	1.2

*Offset Fees paid annually and ~~shall be~~ adjusted annually by the CPI, consistent with the provisions of Rule 320

**For non-RECLAIM sources only

(3) The owner/operator of an EGF ~~using~~ electing to use the offset fee exemption ~~provided by~~ of Rule 1304(a)(2) shall remit the offset fees as follows: ~~initial (5) years of the Annual Offset Fee (F_i), for each applicable pollutant (i), in full, prior to the issuance of the permit to construct. Prior to the end of the fifth (5th) year after the commencement of operation, and annually thereafter, the Annual Offset Fee (F_i), for each applicable pollutant (i), shall be paid in full prior to the renewal date of the permit. If the owner/operator of an EGF fails to pay the Annual Offset Fee (F_i) amount,~~

[2] Proposed revision to Annual and Single Payment Offset Fee Rates under consideration.

~~for each applicable pollutant (i), within thirty (30) days after the due date, the associated permit(s) will expire and no longer be valid.~~

(A) For the annual payment option:

(i) the first year annual payment corresponding to the first year of operation must be remitted prior to the issuance of the permit to construct. Subsequent payments shall be remitted annually, on or before the anniversary date of the commencement of operation, beginning with the second year of operation.

(ii) If the owner/operator of an EGF fails to pay the applicable Annual Offset Fee (F_i) amount, for each applicable pollutant (i), within thirty (30) days after the due date, the associated permit(s) will expire and no longer be valid. Such permit may be reinstated within sixty (60) days with an additional penalty of 50%.

(iii) The owner/operator of an EGF that elects the annual fee payment option has the right to switch to the single payment prior to the commencement of the second year of operation.

For the single payment option, the entire fee must be remitted prior to issuance of the permit to construct.

~~(A)~~(B)

~~The owner/operator of an EGF that elects the annual fee payment option has the right to switch to the single payment option by remitting the balance of the full single payment prior to the commencement of the second year of operation.~~

(4) Offsets provided under the provisions of this rule to a facility are not any form of property, and may not be sold, leased, transferred, or subject to any lien, pledge, or voluntary or involuntary hypothecation or transfer, and shall not be assets in bankruptcy, for purposes of taxation, or in any other legal proceeding.

(5) Refunds of First Year of Annual Payment or Single Payment

The full amount of any payments made in satisfaction of the requirements of the rule shall be refunded if a written request by the facility owner/operator is received prior to the commencement of operation. Such a request for refund shall automatically trigger cancellation of the Permit to Construct and/or Operate.

~~(5) Remittance of Annual Offset Fee (F_i), for each applicable pollutant (i), paid pursuant to paragraph (c)(2), is non-refundable unless~~

~~commencement of operation of the facility has not begun and any refund is only based on the following conditions and schedule:~~

~~Amount of Refund~~	~~Requirement~~
~~50%~~	~~If Permit to Construct is cancelled within the first 12 months of initial issuance.~~
~~20%~~	~~If Permit to Construct is cancelled after the first 12 months of initial issuance but at or before 24 months after initial issuance.~~
~~15%~~	~~If Permit to Construct cancelled after the first 24 months of initial issuance but at or before 36 months after initial issuance.~~
~~10%~~	~~If Permit to Construct is cancelled after the first 36 months of initial issuance but at or before 48 months after initial issuance.~~
~~5%~~	~~If Permit to Construct is cancelled after the first 48 months of initial issuance but at or before 60 months after initial issuance.~~
~~0%~~	~~If Permit to Construct is cancelled after the first 60 months of initial issuance.~~

(d) Use of ~~Annual~~ Offset Fee Proceeds

(1) Except as provided in Paragraph (d)(2), the ~~annual o~~Offset ~~f~~Fee proceeds paid pursuant to this rule shall be deposited in an AQMD

restricted fund account and shall be used to obtain emission reductions consistent with the needs of the Air Quality Management Plan.

(2) Up to 8% of the ~~annual o~~Offset ~~f~~Fee proceeds, deposited in a restricted fund account, may be used by the Executive Officer to cover ~~the costs of administering this rule~~administrative costs related to this rule.

(e) Severability

If any provision of this rule is held by judicial order to be invalid, or invalid or inapplicable to any person or circumstance, such order shall not affect the validity of the remainder of this rule, or the validity or applicability of such provision to other persons or circumstances. In the event any of the exceptions to this rule is held by judicial order to be invalid, the persons or circumstances covered by the exception shall instead be required to comply with the remainder of this rule.

APPENDIX B

NOTICE OF PREPARATION / INITIAL STUDY

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 • www.aqmd.gov

SUBJECT: **NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL ASSESSMENT**

PROJECT TITLE: **PROPOSED RULE 1304.1 – ELECTRICAL GENERATING FACILITY ANNUAL FEE FOR USE OF OFFSET EXEMPTION**

In accordance with the California Environmental Quality Act (CEQA), the South Coast Air Quality Management District (SCAQMD), as the Lead Agency, must address the potential adverse affects of the proposed project on the environment and as such, has prepared a Notice of Preparation (NOP) and Initial Study (IS). The NOP/IS serves two purposes: 1) to solicit information on the scope of the environmental analysis for the proposed project, and 2) to notify the public that the SCAQMD will prepare a Draft Environmental Assessment (EA) to further assess potential adverse environmental impacts that may result from implementing the proposed project.

This letter and NOP/IS are not SCAQMD applications or forms requiring a response from you. Their purpose is simply to provide information to you on the above project. If the proposed project has no bearing on you or your organization, no action on your part is necessary.

Comments focusing on issues relative to the environmental analysis for the proposed project should be sent to Mr. Jeffrey Inabinet (c/o Planning - CEQA) at the above address, by fax to (909) 396-3324, or by email to jinabinet@aqmd.gov. Comments must be received no later than 5:00 p.m. on Wednesday, May 8, 2013. Please include the name, phone number, and email address of the contact person for your agency. Questions on the proposed rule should be directed to Mr. Henry Pourzand by calling (909) 396-2414 or by sending an email to hpourzand@aqmd.gov.

The Public Hearing for the proposed rule is scheduled for September 6, 2013. (Note: Public meeting dates are subject to change).

Date: April 5, 2013 **Signature:** Susan Nakamura

Susan Nakamura
Planning and Rules Manager, CEQA
Planning, Rules, and Area Sources

Reference: California Code of Regulations, Title 14, §§ 15082 (a) and 15375

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765-4178

NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL ASSESSMENT

Project Title:
Draft Environmental Assessment for Proposed Rule 1304.1 – Electrical Generating Facility Annual Fee for Use of Offset Exemption

Project Location:
South Coast Air Quality Management District (SCAQMD) area of jurisdiction consisting of the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin

Description of Nature, Purpose, and Beneficiaries of Project:
SCAQMD staff is proposing to adopt Rule 1304.1 - Electrical Generating Facility Annual Fee for Use of Offset Exemption. If adopted, Proposed Rule (PR) 1304.1 will require any electrical generating facility (EGF) that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 Air Quality Management Plan (AQMP), and minimize the air quality impacts that an EGF may have on its surrounding community. The Initial Study identified the environmental topics of "air quality" and "energy" as the only areas that may be adversely affected by the proposed project. Impacts to these environmental areas will be further analyzed in the Draft Environmental Assessment.

Lead Agency:	**Division:**
South Coast Air Quality Management District	Planning, Rule Development and Area Sources

Initial Study and all supporting documentation are available at:	**or by calling:**	**or by accessing the SCAQMD's website at:**
SCAQMD Headquarters 21865 Copley Drive Diamond Bar, CA 91765	(909) 396-2039	http://www.aqmd.gov/ceqa/aqmd.html

The Public Notice of Preparation is provided through the following:

☑ Los Angeles Times (April 9, 2013) ☑ SCAQMD Website ☑ SCAQMD Mailing List

Initial Study 30-day Review Period:
April 9, 2013 – May 8, 2013

The proposed project may have statewide, regional or areawide significance; therefore, a CEQA scoping meeting is required (pursuant to Public Resources Code §21083.9 (a)(2)).

Scheduled Public Meeting Dates (subject to change):
CEQA Scoping Meeting: To be announced
SCAQMD Governing Board Hearing: September 6, 2013, 9:00 a.m.; SCAQMD Headquarters

Send CEQA Comments to:	**Phone:**	**Email:**	**Fax:**
Mr. Jeffrey Inabinet	(909) 396-2453	jinabinet@aqmd.gov	(909) 396-3324
Direct Questions on Proposed Rule: Mr. Henry Pourzand	**Phone:** (909) 396-2414	**Email:** hpourzand@aqmd.gov	**Fax:** (909) 396-3324

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Initial Study for Proposed Rule 1304.1 – Electrical Generating Facility Annual Fee For Use of Offset Exemption

April 2013

SCAQMD No. 04092013JFI
State Clearinghouse No: To Be Determined

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Author:	Jeff Inabinet	Air Quality Specialist, CEQA Section
Reviewed By:	Barbara Baird	District Counsel
	Naveen Berry	Planning and Rules Manager, Planning, Rule Development, and Area Sources
	Robert Pease	Program Supervisor - Planning, Rule Development, and Area Sources
	Henry Pourzand	Air Quality Specialist, Rule Development
	Barbara Radlein	Air Quality Specialist, CEQA Section
	Veera Tyagi	Senior Deputy District Counsel

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Mayor, Santa Ana
Cities of Orange County

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

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INITIAL STUDY

APPENDIX

GENERAL INFORMATION

Project Title:	Proposed Rule 1304.1 - Electrical Generating Facility Annual Fee for Use of Offset Exemption
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive, Diamond Bar, CA 91765
CEQA Contact Person:	Jeff Inabinet, (909) 396-2453, jinabinet@aqmd.gov
Rule Contact Person:	Henry Pourzand, (909) 396-2414, hpourzand@aqmd.gov
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive, Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Surrounding Land Uses and Setting:	The four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties) and the Riverside County portion of the Mojave Desert Air Basin, referred to herein as the district.
Other Public Agencies Whose Approval is Required:	None.
Does this project relate to a larger project or series of projects?	No.

INTRODUCTION

The South Coast Air Quality Management District (SCAQMD) is proposing to adopt a new rule, Proposed Rule (PR) 1304.1 – Electrical Generating Facility Annual Fee for Use of Offset Exemption. If adopted, PR 1304.1 would require any electrical generating facility (EGF) that uses the specific offset exemption described in SCAQMD Rule 1304 (a)(2) - Electric Utility Steam Boiler Replacement, to pay fees for up to the full amount of offsets provided by the SCAQMD. Offsets in SCAQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with the requirements in Rule 1304 (a)(2).

PROJECT BACKGROUND

New Source Review and the Requirement for Offsets

Under the federal Clean Air Act (CAA), a State Implementation Plan (SIP) for a nonattainment area must include a "New Source Review" (NSR) permitting program for the construction and operation of new and modified "major" stationary sources of air emissions[1]. These requirements do not apply to mobile sources such as cars, trucks and ships. The definition of what constitutes a "major" stationary source under the CAA depends on the extent to which the region in question is in nonattainment for a particular pollutant. The Basin is classified as an "extreme" nonattainment region for ozone and, therefore, the threshold for triggering the NSR requirements for ozone is lower than in the Coachella Valley, which is classified as a "severe" nonattainment area for ozone. It should be noted that the SCAQMD's permitting requirements are broader than the federal NSR requirements in that the SCAQMD's requirements apply to ***all*** stationary sources that would result in a net increase in emissions of any nonattainment pollutant, even if the source does not qualify as a "major" source under the CAA.

The CAA's NSR permitting requirements are designed to ensure that the operation of new, modified, or relocated major stationary emission sources in nonattainment areas does not impede the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS). Under the CAA, all local major NSR permitting programs for nonattainment areas must require the implementation of the lowest achievable emissions rate (LAER). LAER is the most stringent emissions limitation derived from either of the following: 1) the most stringent emissions limitation contained in any state's SIP for the class or category of source at issue, unless it is demonstrated that such a limitation is not achievable; or, 2) the most stringent emissions limitation achieved in practice by that class or source category.

In addition, all local NSR permitting programs for nonattainment areas must require that emissions increases from permitted major sources are "offset" by corresponding emissions reductions[2]. An "offset" is a reduction of emissions in an amount equal to, or greater than, the emissions increase of the same pollutant from the permitted source. Offsets can be created when

[1] The CAA also establishes permitting requirements for major sources of emissions located in attainment regions, in order to prevent a significant deterioration of air quality in those areas.
[2] The NSR offset requirements are set forth in Section 173 (c) of the CAA, 42 U.S.C. §7503(c).

an operator reduces emissions by shutting down equipment or installing controls, or implementing permanent process changes resulting in emissions reductions that are not required. The specific quantity of the offset that is required under the CAA depends on the degree of nonattainment in the area in question. The SCAQMD's offset requirements are discussed in greater detail below.

Overview of California Law

Similar to the federal CAA, the California Health & Safety Code (§§39000 *et seq.*) requires the promulgation of California Ambient Air Quality Standards (CAAQS) for certain pollutants. The California Air Resources Board (CARB) has published CAAQS for the six criteria pollutants regulated under the federal CAA, and for three other pollutants (sulfates, hydrogen sulfide and vinyl sulfide). As with the federal CAA, an area that does not meet the CAAQS for a particular pollutant is designated as a state nonattainment area for that pollutant and the local air district must develop a plan to attain the relevant CAAQS. In general, the California standards are more protective than the corresponding federal standards.

CARB has published in its regulations the state law designations for attainment with the CAAQS. See 17 Cal. Code Regs. §§ 60200 et seq. The Basin, the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB) have all been designated in their entirety as nonattainment areas for the CAAQS for ozone and PM10. See id. §§ 60201, 60205. The Basin also has been designated as a state nonattainment area for PM2.5. See id. § 60210. In addition, CARB adopted new regulations that designated the Basin as a state nonattainment area for nitrogen dioxide and the Los Angeles County portion of the Basin as a state nonattainment area for lead. See CARB Resolution 10-17 (March 25, 2010). While to date, EPA has no nonattainment listings for nitrogen dioxide, on November 16, 2010, after reviewing input on initial nonattainment designations, the EPA designated the Los Angeles County portion of the Basis as nonattainment for the 2008 lead standards.

California law requires local air districts in nonattainment areas to implement a stationary source control program designed to achieve no net increase (NNI) in emissions of certain state nonattainment air pollutants from new or modified stationary sources exceeding specified emissions thresholds. As under the CAA, the applicable thresholds depend on the degree of nonattainment in the area in question.

Description of SCAQMD's NSR Permitting Program

<u>Contents of Regulation XIII – New Source Review</u>
The SCAQMD's NSR program, which is codified in the SCAQMD's "Regulation XIII," is designed to meet the requirements of federal and state law[3]. Each of the existing rules in Regulation XIII that collectively comprise the SCAQMD's NSR program is summarized in the following bulleted items:

[3] Separate NSR requirements for RECLAIM pollutants (NOx and SOx) at RECLAIM facilities are included in Rule 2005. RECLAIM (Regional Clean Air Incentives Market) is a cap and trade program consisting of the largest stationary sources of these pollutants, and Regulation XIII does not apply to these pollutants at RECLAIM sources.

- **Rule 1301 – General** (adopted October 5, 1979, last amended December 7, 1995): Rule 1301 describes the purpose and applicability of Regulation XIII. As stated in Rule 1301, the purpose of the SCAQMD's NSR program is to ensure that the operation of new, modified or relocated facilities does not interfere with progress in attaining the NAAQSs and the CAAQS, and that future economic growth within the district is not unnecessarily restricted. Rule 1301(a). A specific goal of the program "is to achieve no net increases from new or modified permitted sources of nonattainment air contaminants or their precursors." *Id*. The program applies to the installation of a new source, or the modification of an existing source, that may cause emissions of any federal or state nonattainment air contaminant, any constituent identified by the USEPA as an ozone depleting compound, or ammonia. Rule 1301 (b)(1).
- **Rule 1302 – Definitions** (adopted October 5, 1979, last amended December 6, 2002): Rule 1302 provides definitions for 42 terms and phrases used throughout Regulation XIII.
- **Rule 1303 – Requirements** (adopted October 5, 1979, last amended December 6, 2002): Rule 1303 presents the pre-construction review requirements that make up the core of SCAQMD's NSR program.
  - The requirements include Best Available Control Technology (BACT) for new or modified sources that may cause an increase in emissions of any federal or state nonattainment air contaminant, any ozone depleting compound, or ammonia. Rule 1303 (a). Under the SCAQMD regulations, BACT means the most stringent emissions limitation which: 1) has been achieved in practice for the category or class of source at issue; 2) is contained in any SIP approved by the USEPA for such category or class; or, 3) is based on any other emissions limitation or technique that has been found by the SCAQMD to be technologically feasible and cost-effective. Rule 1302 (h). For "major polluting facilities[4]," the BACT requirements must be at least as stringent as the federal LAER requirements under the CAA. Rule 1303 (a)(2). With respect to other facilities, when updating BACT requirements to make them more stringent, the SCAQMD must consider economic and technological feasibility for the class or category of sources at issue. *Id.*
  - Rule 1303 (b)(1) also requires modeling to show that the new or modified source will not cause a violation, or make significantly worse an existing violation, of any NAAQS or CAAQS at any receptor location in the district.
  - Rule 1303 (b)(2) further requires that, unless there is an exemption under Rule 1304 (see below), emissions increases from the new or modified permitted source must be offset by one of two methods.
    - First, under Rule 1309 (see below), for projects that meet specified eligibility requirements, the applicant can use Emissions Reductions Credits (ERCs),

[4] Under the SCAQMD's regulations, a "major polluting facility" is: 1) any facility in the Basin that has the potential to emit 10 tons per year or more of volatile organic compounds (VOCs) or NO_x, or 100 tons of per year of oxides of sulfur (SO_x); 70 tons per year or more of PM10; or 50 tons per year or more of CO; 2) any facility in the Riverside County portion of the SSAB that has the potential to emit 25 tons per year or more of VOCs or NO_x; 70 tons per year or more of PM10; or 100 tons per year or more of CO or SO_x; or, 3) any facility in the Riverside County portion of the MDAB under the SCAQMD's jurisdiction that has the potential to emit 100 tons per year or more of any of these compounds. See Rule 1302 (s).

which are created when an operator reduces emissions from a permitted facility. Once ERCs are created, operators may bank ERCs for their own subsequent use or for sale to other permit applicants.

- Second, under Rule 1309.1 (see below), the SCAQMD may allocate credits from its "Priority Reserve" to offset emissions from "essential public services" and other specified "priority sources." As described more fully below, the Priority Reserve is part of an internal "bank" or internal accounts of offsets that the SCAQMD accumulates primarily from "orphan" reductions and shutdowns which occur when an operator reduces emissions from a permitted facility but does not convert the emissions reduction into ERCs. This bank of offsets is referred to in the SCAQMD regulations, and this document, as the SCAQMD's "internal offset accounts."

- Rule 1303 (b)(2)(A) specifies the required offset ratio in terms of the amount of emissions reductions that is needed to compensate for the increase in emissions from the permitted source. For facilities located in the Basin, the required offset ratios are 1.0-to-1.0 for allocations from the Priority Reserve[5] and 1.2-to-1.0 for the use of ERCs. For facilities not in the Basin, the required offset ratios are 1.0-to-1.0 for allocations from the Priority Reserve; 1.2-to-1.0 for ERCs for emissions of VOCs, NO_x, SO_x, and PM10; and 1.0-to-1.0 for ERCs for emissions of CO. (Note: the district has achieved the California Ambient Air Quality standards for CO and has been designated as in attainment for the federal standards, so CO emissions are no longer required to be offset.)
- Rule 1303 also includes additional permitting requirements for "major polluting facilities" (as defined above) and "major modifications"[6] at an existing major polluting facility. These requirements include an analysis of alternatives (this requirement may be satisfied through CEQA compliance), a demonstration by the applicant that its facilities in California comply with applicable air quality requirements, and modeling of plume visibility for certain sources of PM10 or NO_x located near specified areas.

- **Rule 1304 - Exemptions** (adopted October 5, 1979, last amended June 14, 1996): Rule 1304 establishes exemptions from the offset requirements in Rule 1303 for the following categories of projects:
  - Replacement of a functionally identical source.

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[5] Although the offset ratio for credits allocated from the SCAQMD's Priority Reserve account is 1.0-to-1.0, this ratio is for accounting purposes of limiting the use of the Priority Reserve to the level authorized by Rule 1309.1 only and is not the offset ratio used for demonstrating equivalency with federal offset requirements. If the facility accessing the Priority Reserve is a major source then the actual ratio of credits allocated from the SCAQMD's federal offset accounts would be 1.2-to-1.0 for extreme nonattainment air contaminants and their precursors to comply with federal offset requirements.

[6] Under the SCAQMD's regulations, a "major modification" is a modification of a major polluting facility that will cause an increase of the facility's potential to emit according to the following criteria: a) for facilities in the Basin, one pound per day of more of VOCs or NO_x; b) for facilities under the SCAQMD's jurisdiction that are not in the Basin, 25 tons per year or more of VOCs or NO_x; or, c) for all facilities under the SCAQMD's jurisdiction, 40 tons per year or more of SO_x, 15 tons per year or more of PM10, or 50 tons per year or more of CO. Rule 1302 (r).

- o Replacement of electric utility steam boilers with specified types of equipment, as long as the new equipment has a maximum electric power rating that does not allow basinwide electricity generating capacity on a per-utility basis to increase (a)(2).
- o Portable abrasive blasting equipment complying with all state laws.
- o Emergency standby equipment for nonutility electric power generation or any other emergency equipment as approved by the SCAQMD, provided the source does not operate more than 200 hours per year.
- o Air pollution control strategies (i.e., source modifications) for the sole purpose of reducing emissions.
- o Emergency operations performed under the jurisdiction of an authorized health officer, fire protection officer, or other authorized public agency officer. Rule 1304 requires that a specific time limit be imposed for each emergency operation.
- o Portable equipment that is not located for more than 12 consecutive months at any one facility in the district. This exemption does not apply to portable internal combustion engines.
- o Portable internal combustion engines that are not located for more than 12 consecutive months at any one facility in the district. To qualify for this exemption, the emissions from the engine may not cause an exceedance of an ambient air quality standard and may not exceed specified limits for VOCs, NOx, SOx, PM10 or CO.
- o Intra-facility portable equipment meeting specified criteria where emissions from the equipment do not exceed specified emissions thresholds for any of the constituents listed in the bulleted item above.
- o Relocation of existing equipment, under the same operator or ownership, and provided that the potential to emit any air contaminant will not be greater at the new location than at the previous location when the source is operated at the same conditions as if current BACT were applied.
- o Concurrent facility modifications, which are modifications to a facility after the submittal of an application for a permit to construct, but before the start of operation. The modifications must result in a net emissions decrease and other conditions must also be satisfied.
- o Resource recovery and energy conservation projects.
- o Regulatory compliance actions (i.e., modifications to comply with federal, state or SCAQMD pollution control requirements), provided there is no increase in the maximum rating of the equipment.
- o Regulatory compliance for essential public services.
- o Replacement of ozone depleting compounds (ODC), provided the replacement complies with the SCAQMD's "ODC Replacement Guidelines" and meets other specified criteria.
- o Methyl bromide fumigation.

- New and modified facilities with only minimal potential to emit (less than four tons per year of VOCs, NOx, SOx, or PM10 and less than 29 tons per year of CO).
- Although SCAQMD Rule 1304 exempts certain types of projects from offset requirements, if they are federal major sources their emission increases are still subject to federal offset requirements pursuant to the CAA's emission requirements. Additionally, specific essential public services and other high priority sources may obtain offsets from the SCAQMD's Priority Reserve pursuant to SCAQMD Rule 1309.1. The NSR Tracking System accounts for offsets provided from the SCAQMD's internal accounts to offset emissions increases from these types of sources.

- **Rule 1306 – Emissions Calculations** (adopted October 5, 1979, last amended December 6, 2002): Rule 1306 codifies the methodology for quantifying emissions increases and emissions reductions for Regulation XIII purposes (e.g., determining applicability of BACT, quantifying the amount of emission offsets required or the amount of ERCs to be banked), but is not applicable to the SCAQMD's internal accounts.
- **Rule 1309 – Emission Reduction Credits and Short Term Credits** (adopted September 10, 1982, last amended December 6, 2002): Rule 1309 sets forth the requirements for eligibility, registration, use and transfer of ERCs for use as offsets under Rule 1303 (b)(2), but is not applicable to the SCAQMD's internal accounts. Among other topics, the rule addresses the validation of past emissions decreases for use as ERCs; the application for an ERC for a new emissions reduction; interpollutant offsets; and inter-basin and inter-district offsets.
- **Rule 1309.1 – Priority Reserve** (adopted June 28, 1990, last amended May 3, 2002[7]): Rule 1309.1 establishes the Priority Reserve, which is part of the SCAQMD's internal accounts of emission offsets. The SCAQMD accumulates offsets in the Priority Reserve primarily from orphan shutdowns and reductions. The SCAQMD then allocates these offsets to meet offset requirements when issuing permits for "essential public services," which are defined to include publicly owned or operated sewage treatment plants, prisons, police and firefighting facilities, schools, hospitals, landfill gas control or processing facilities, water delivery facilities, and public transit facilities. The SCAQMD also allocates offsets from the Priority Reserve when issuing permits for other specified priority sources, such as innovative technologies that result in lower emissions rates and experimental research activities designed to advance the state of the art. The rule requires that, before an eligible facility may use offsets from the Priority Reserve for a particular pollutant, the facility must first use any ERCs that it holds for that pollutant. Rule 1309.1 also enables EGFs to access to the Priority Reserve and allows projects less than 50 MegaWatts (MW) that generate a substantial portion of their electricity to pump water to maintain the integrity of the surface elevation of a municipality or significant portion thereof to qualify as an EGF. In addition, the following requirements apply to projects receiving credits from the Priority Reserve:

[7] Subsequent amendments to Rule 1309.1 in 2006 were replaced by the 2007 amendments, which were invalidated as a result of litigation.

- Modifying all of the EGF's sources to BARCT for the pollutant(s) obtained (if applicable) not later than 3 years after issuance of the permit for the new source(s).
- Paying a non-refundable mitigation fee of $8,900 per pound per day for each pound of SO_2 obtained from the Priority Reserve.
- Paying a non-refundable mitigation fee of $12,000 per pound per day for each pound of CO obtained from the Priority Reserve.
- Submitting a complete application for a permit during calendar years 2000, 2001, 2002, or 2003 and the EGF becoming fully operational within three years after permitting.
- Making a good faith effort to obtain offsets including ERCs, state emissions bank credits, and credits from SIP approved credit generation programs (limited to rates not to exceed the mitigation fee).

- **Rule 1310 – Analysis and Reporting** (adopted October 5, 1979, last amended December 7, 1995): Rule 1310 addresses the Executive Officer's application completeness determinations, annual reports to the Governing Board regarding the effectiveness of Regulation XIII and public notice requirements for banking ERCs above specified threshold amounts.
- **Rule 1313 – Permits to Operate** (adopted October 5, 1979, last amended December 7, 1995): Rule 1313 exempts permit renewal, change of operator, or change in Rule 219 – Equipment Not Requiring a Written Permit Pursuant to Regulation II, from the SCAQMD's NSR program, specifies that an application for a permit to operate a source that was constructed without a prior permit to construct is considered an application for a permit to construct for purposes of the SCAQMD's NSR program, establishes a 90-day deadline for facility operators to provide emissions offsets requested by the Executive Officer for a permit to operate, provides a window of up to 90 days for a replacement source to operate concurrently with the source it is replacing, specifies the inclusion of NSR permit conditions on permits, and specifies that relaxing or removing a condition limiting mass emissions from a permit is subject to NSR if that condition limited the source's obligations under NSR.
- **Rule 1315 – Federal New Source Review Tracking System** (Adopted September 8, 2006, Re-Adopted August 3, 2007, Repealed January 8, 2010, and Re-adopted February 4, 2011): Rule 1315 codifies SCAQMD procedures for establishing equivalency under federal New Source Review requirements. Equivalency means that the SCAQMD provides sufficient offsets from its internal offset accounts to cover the emission increases from new or modified sources that are exempt from offsets under SCAQMD rules or that obtain credits from the Priority Reserve, but are subject to offset requirements under federal law. Rule 1315 ensures that exempt sources under Rule 1304 and essential public services and other projects that qualify for Priority Reserve offsets under Rule 1309.1 are fully offset to the extent required by federal law, using valid emission reductions from the SCAQMD's internal offset accounts. Rule 1315 also specifies what types of emissions reductions are eligible to be deposited into the SCAQMD's internal offset accounts, including newly-tracked reductions. "Newly tracked" emissions reductions are reductions that had not been historically tracked until the adoption of a prior version of Rule 1315 in 2006.

- **Rule 1316 – Federal Major Modifications** (Adopted December 2, 2005): Rule 1316 establishes that if a permit applicant demonstrates that a proposed modification to an existing stationary source would not constitute a Federal Major Modification (as defined in the USEPA's regulations in 40 CFR §51.165) the proposed modification is exempt from the analysis of alternatives otherwise required by Rule 1303. Rule 1316 also allows applicants for major polluting facilities to apply for a plantwide applicability limit (PAL), which is a cap on facility-wide emissions of a particular pollutant that allows the operator to make modifications to the facility without triggering the alternatives requirement of Rule 1303, as long as the requirements for PALs are met and the cap is not exceeded.
- **Rule 1325 – Federal PM2.5 New Source Review Program** (Adopted June 3, 2011): Rule 1325 applies to new and modified major sources that trigger the NSR threshold for PM2.5. A major source is defined as having a potential to emit 100 tons per year of PM2.5. Rule 1325 mirrors federal requirements for PM2.5. Rule thresholds, major modification levels, emission offsets, and other requirements In Rule 1325 are taken directly from U.S. EPA requirements.

1996 Tracking System

Since 1996, as a part of the SCAQMD's effort to track emissions offsets in its internal offset accounts, SCAQMD staff has prepared a series of reports that track credits and debits from August 1990 through July 2002 and present the remaining balances of credits in the SCAQMD's federal and California offset accounts. These NSR tracking reports go back to the year 1990[8] because that was the year when fundamental amendments were made to the SCAQMD's Regulation XIII. A key source of credits in these tracking reports was orphan shutdowns of federal major sources (for purposes of demonstrating equivalency with federal offset requirements) and of sources with potential to emit above California's "no net increase" (NNI) applicability thresholds (for purposes of demonstrating equivalency with California NNI requirements). In other words, when a facility had previously reduced emissions by shutting down equipment or installing control equipment or implementing permanent process changes that were not required, but did not claim an ERC or had originally obtained its offset from SCAQMD, the SCAQMD allocated that reduction as a credit in its internal offset accounts. The USEPA's 1996 approval of the SCAQMD NSR program confirmed its use of emissions reductions from orphan shutdowns as a source of offset credits. The USEPA also indicated that other appropriate credit sources included, for example, the "BACT discount[9]" required by

[8] Prior to 1990 SCAQMD kept a running "NSR balance" for each facility with permitted stationary sources. The NSR balance included an entry for every increase and every decrease in emissions at a facility that resulted from a permit action since October, 1976, when the SCAQMD first implemented an NSR program. When the SCAQMD modified Regulation XIII in 1990, it discounted and carried forward into its internal accounts the pre-1990 NSR balance for facilities that had a "negative balance," i.e., the decreases in emissions exceeded the cumulative increases at the facility.

[9] The BACT discount serves to reduce the amount of the ERC that may be claimed when a facility curtails or reduces or ceases emissions. In particular, instead of obtaining an ERC for the amount of the actual reduction in emissions, the facility may claim an ERC under the SCAQMD's regulations only for the amount of the reduction that would have occurred if the facility was equipped with then-current BACT at the time the reduction occurred. The CAA does not require this discount, but USEPA later indicated that the BACT discount operated as a substitute for USEPA's requirement that ERCs be shown to be "surplus at the time of use" and therefore could not be used to generate offsets, unless the discount is demonstrated to exceed the reductions that would be required by SCAQMD rules in the SIP scheduled to be adopted in the following year.

Regulation XIII (specifically Rule 1306 (c)) when a facility banks ERCs; and surplus emissions reductions, which occur when an offset is required under the SCAQMD regulations, but not under the CAA. In addition, USEPA confirmed that the internal bank would provide offsets for priority reserve sources under Rule 1309.1 and for facilities that are exempt under SCAQMD Rule 1304, but which are not exempt under the CAA from the federal offset requirements.

Changes to Tracking System

In 2002, the SCAQMD adopted a new Rule 1309.2 to provide for an "offset budget" for projects that do not qualify for Priority Reserve credits[10]. The rule was submitted to USEPA for approval as part of the California SIP, and during its review of that rule USEPA raised the issue of whether the SCAQMD had retained adequate documentation of certain emissions reductions that arose from shutdowns occurring before 1990. After an exhaustive internal review of its documentation, the SCAQMD established to USEPA's satisfaction that its records supported many of the pre-1990 offset credits, and agreed to remove from its internal accounts those pre-1990 offset credits for which the SCAQMD no longer possessed sufficient documentation. The USEPA approved the revised tracking system in April 2006, including the use by the SCAQMD of previously unclaimed orphan shutdown credits[11] and also requested that the SCAQMD describe its internal offset tracking system in a rule.

After a series of lawsuits, Rule 1315 was eventually adopted by the SCAQMD Governing Board on February 4, 2011. The purpose of Rule 1315 is to ensure that exempt sources under Rule 1304 and essential public services and other projects that qualify for Priority Reserve offsets under Rule 1309.1 are fully offset to the extent required by federal law by valid emission reductions from the SCAQMD's internal offset accounts. Rule 1315 achieves this by specifying what types of reductions are eligible to be credited as offsets to SCAQMD's internal accounts and how those reductions are tracked.

PROJECT DESCRIPTION

The purpose of PR 1304.1 – Electrical Generating Facility Annual Fee for Use of Offset Exemption, is to require any EGF that uses a specific offset exemption (Rule 1304.1 (a)(2)) to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Offsets in SCAQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304(a)(2). The fee proceeds will be invested in air pollution improvement projects that further the goals of the 2012 AQMP, and reduce the air quality impacts that an EGF project would have on its surrounding community through other air pollution reduction strategies.

[10] The SCAQMD rescinded Rule 1309.2 in February 2010.

[11] The various changes that the SCAQMD proposed in 2006 to its pre-existing emissions offset tracking system are documented in a submittal to the USEPA in February 2006. See SCAQMD's Revised NSR Offset Tracking System, February 23, 2006. These changes were approved in a letter from Deborah Jordan, USEPA, to Dr. Barry Wallerstein, SCAQMD, April 11, 2006, re: "Proposed NSR Offset Tracking System."

The proposed rule affects all electrical generating facilities that elect to use the offset exemptions described in Rule 1304 (a)(2), but not those facilities that meet their emissions obligations through privately held/procured offset credits.

The following is a summary of the key proposed concepts of PR 1304.1. A copy of the proposed rule can be found in Appendix A.

- EGFs encumbering/obtaining offsets from the SCAQMD Offset Accounts shall either pay an Annual Offset Fee (F_i), for each pollutant (i), (specifically PM10, NOx, SOx and/or VOC) as applicable to the project/unit(s) or a single, up-front fee for applicable offsets.
- The total EGF annual fee will be based on the total quantity of offsets utilized from the SCAQMD internal offset accounts for each of the pollutants in pounds per day multiplied by the Annual Fee Rate, for each pollutant, in dollars per pound per day or a single, up-front payment for the use of the offsets for the duration of the project. There are also separate fee structures for less than 100 megawatts and greater than 100 megawatts of generation.
- The annual fee rate or a single, up-front payment for each pollutant is proposed to be derived based on the historical transaction values of Emission Reduction Credits in the open market. The annual fee rate option would have the payment adjusted annually by the consumer price index (CPI).
- EGF owners/operators electing the annual fee option would be required to pay the annual fee for the first year upfront prior to issuance of the permit to construct the new replacement unit(s), and then annually each year thereafter during any part of which the new replacement unit(s) remain in operation, and for as long as the new replacement unit(s), project and/or EGF are operated. EGF owners/operators electing the single, up-front payment option shall pay the entire fee prior to the issuance of the permit to construct.
- The full amount of any payments made in satisfaction of the requirements of the rule shall be refunded if a written request by the facility owner/operator is received prior to the commencement of operation. Such a request for refund shall automatically trigger cancellation of the Permit to Construct and/or Operate.
- Fees collected will be invested in air pollution improvement projects that further the goals of the 2012 AQMP and reduce emissions of pollutants for which the fee is charged or their precursors or pollutants to which they contribute.

ENVIRONMENTAL CHECKLIST AND DISCUSSION

The SCAQMD has prepared this streamlined environmental checklist to assist with identifying potential adverse environmental impacts from the proposed project. The environmental checklist form may be tailored to satisfy individual agency needs and project circumstances, and may be used for an initial study when the criteria set forth in CEQA Guidelines have been met. This streamlined environmental checklist adequately evaluates all environmental topic areas outlined in Appendix G of the CEQA Guidelines. The environmental checklist discussion also identifies some of the overarching assumptions that will be used to analyze potential adverse environmental impacts from proposed Rule 1304.1.

Are the following items applicable to the project or its effects? Discuss rationale for each checked item.

	Yes	No
1. Would the proposed project have the potential to change scenic views or vistas, create a new source of substantial light or glare, or substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Existing facilities where operators choose to use SCAQMD provided offsets and pay a fee as a result of adopting the proposed project are typically located in appropriately zoned areas, primarily industrial and commercial, often devoid of scenic views or vistas and are not likely to be located in existing residential areas or public lands. Although such facilities would likely be located on or near public roadways, roadways in commercial or industrial areas are not typically designated as scenic highways[12]. No construction or other physical changes would be necessary that could affect scenic views or vistas in existing residential areas or public lands or roads, as a result of this rule adoption. Further, the proposed project would not directly or indirectly result in the creation of new uses and facilities that would affect aesthetic resources. Consequently, the proposed project is not expected to change in any way existing scenic views or vistas in existing residential areas or public lands or roads, create a new source of substantial light or glare, or substantially damage any scenic resources. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
2. Would the proposed project convert farmland to non- agricultural use or conflict with existing zoning for agricultural use?	☐	☑

Discussion: The proposed project would not directly or indirectly result in any construction of new buildings or other structures that would convert farmland to non-agricultural use or

[12] A review of designated scenic highways and highways within district boundaries eligible for state scenic highway designation indicates that such highways are typically located along coastal, hilly, or mountainous areas, not near major population centers where commercial or industrial facilities would typically be located. (California Scenic Highway Mapping System accessed at http://www.dot.ca.gov/hq/LandArch/scenic_highways/index.htm on 1/3/2013.)

conflict with zoning for agricultural use or a Williamson Act contract. There are no provisions in the proposed rule or amended rule that would convert farmland to non-agricultural uses, thus, affecting land use plans, policies, or regulations related to agricultural resources. Land use and other planning considerations are determined by local governments, and no land use or planning requirements would be directly or indirectly altered by the proposed project. As such, the proposed project does not have direct or indirect impacts on agricultural resources. If an EGF in the future were to be sited on agricultural land, that decision would be outside the scope and not a result of this project and would require approval from an agency with land use authority. Thus, these commercial and industrial projects are not expected to result in the conversion of Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland) to non-agricultural uses. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
3. Would the proposed project have the potential to generate criteria, toxic, or greenhouse gas pollutant emissions; smoke; fumes; or odors?	☑	☐

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. The proposed project is, therefore, consistent with the existing purposes of Regulation XIII to ensure that there are no net increases in emissions from new or modified permitted sources. However, the SCAQMD has received comments from stakeholders asserting that implementing fees pursuant to PR 1304.1 may deter investment in replacing 50+ year-old boilers with new more efficient gas turbines or other more efficient gas turbines, etc. As a result, because of comments raised claiming potential transmission constraints and increased local reliability needs, the Draft EA will analyze the potential increase in boiler use and a concurrent increase in boiler emissions. The potential adverse criteria pollutants, air toxic, and greenhouse gases (GHG) emission impacts will be analyzed at the project level and cumulatively with other related projects, as necessary, in the Draft EA.

	Yes	No
4. Would the proposed project have the potential to create an adverse impact on sensitive/special status species or on any riparian habitat or other sensitive natural community?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Accordingly, the proposed project is not expected to have direct or indirect impacts on plant or animal species or the habitats that support them. PR 1304.1 primarily affects existing facilities where operators choose to use SCAQMD provided offsets and pay a fee. Therefore, the affected EGFs are primarily located at existing facilities that have already been constructed and are in operation. Thus, substantial adverse impacts on sensitive/special status species or any riparian habitat or other sensitive natural community are unlikely to occur as a result of PR 1304.1. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
5. ***Would the proposed project have the potential to require demolition, excavating/ grading/construction activities, result in the loss of availability of a known mineral resource, cause a substantial adverse change in the significance of a cultural resource, or is the proposed project located in the vicinity of a known earthquake fault?***	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities located at sites that have already been disturbed as a result of site preparation. Implementing PR 1304.1 would not change current operating practices and procedures of EGFs. Thus, no demolition, excavating/grading, or other construction activities of any kind are expected from implementing the proposed project. Additionally, implementation of PR 1304.1 is not expected to result in the loss of a known mineral resource or cause a substantial adverse change in the significance of a cultural resource. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
6. ***Would the proposed project have the potential to increase the energy demand (electricity, oil, natural gas, etc.) and/or increase the need for new energy utilities?***	☑	☐

Discussion: Affected facilities would still be expected to comply with any existing energy conservation standards, to the extent that affected equipment is subject to energy conservation standards. However, the SCAQMD has received comments from stakeholders asserting that implementing fees pursuant to PR 1304.1 would deter investment in replacing 50+ year-old boilers with new more efficient gas turbines or other more efficient gas turbines, etc. Therefore, the Draft EA will evaluate whether delayed equipment replacement would have an impact on the electricity supply system as a result of rule adoption. Additionally, the Draft EA will determine whether the potential for the San Onofre Nuclear Generating Station (SONGS) extended power outage would be an exacerbation of any impact.

	Yes	No
7. ***Would the proposed project have the potential to create a substantial demand for municipal public services (fire or police), induce substantial growth in an area either directly or indirectly, or displace substantial numbers of existing housing/people?***	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. Population will not be affected directly or indirectly as a result of adopting and implementing the proposed project. The proposed project would not directly or indirectly result in the creation of new uses and facilities that would affect population growth or induce growth. The proposed project is not expected to appreciably affect employment opportunities and, as such, is not expected to result in the relocation or redistribution of population or growth inducement. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
8. Would the proposed project have the potential to result in a substantial change in existing noise or vibration levels?	☐	☑

Discussion: PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. Implementing PR 1304.1 would not change current operating practices and procedures of EGFs. Although the representative facilities could generate an increase in noise if new or modified equipment was installed, they are not expected to expose persons to or generate noise levels in excess of standards established in a local general plan or noise ordinance because violating such standards and ordinances would subject the affected facilities to local jurisdiction enforcement and penalty actions, which could jeopardize further operation of the facility. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
9. Would the proposed project have the potential to change the demand or the quality of potable water or groundwater and/or increase the need for water/wastewater utilities?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. The proposed project would have no direct impact on hydrology and water quality. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. The proposed project does not require equipment modification. However, if EGFs decided to upgrade with new more efficient gas turbines, the equipment is typically located in existing structures or on existing concrete pads, so no construction activities or other physical changes would be necessary that could disturb soils. Therefore, watering to reduce fugitive dust emissions pursuant to Rule 403 would not be required. Further, the proposed project would not be expected to change current operating practices and procedures that would increase the need for additional water supplies or water utilities. Implementation of PR 1304.1 is not expected to increase the demand for water or increase the amount of wastewater generated. Therefore, no changes to groundwater quality or increases in the need for water/wastewater utilities are anticipated. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
10. Would the proposed project have the potential to alter existing drainage patterns?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. Therefore, PR 1304.1 would not require purchasing additional land or promote further construction of any buildings or other structures that may have the potential to alter drainage patterns. Additionally, EGFs affected by the proposed project would not be expected to change current operating practices and procedures. Thus, no alterations to existing drainage patterns are expected from implementing the proposed project. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
11. Would the proposed project have the potential to generate substantial amounts of solid or hazardous wastes or create a significant hazard to the public or the environment?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. Implementing PR 1304.1 would not change current operating practices and procedures of EGFs, so no changes in the existing volumes of solid or hazardous wastes generated at affected facilities are anticipated. The proposed project would not directly or indirectly result in increased transport, storage, or use of hazardous materials. Therefore, the proposed project would have no direct hazards or hazardous materials impacts. Additionally, PR 1304.1 would not require any physical changes or installation of control equipment that would generate substantial amounts of solid or hazardous wastes. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
12. Would the proposed project have the potential to increase the number of passenger vehicle and/or heavy-duty truck trips or exceed, either individually or cumulatively, a level of service standard?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. The proposed project would not require significant physical changes at affected facilities, so construction activities that could generate construction worker commute trips or heavy-duty haul truck trips would not occur. Similarly, the proposed project would not change current operating practices and procedures, so new employees and associated employee commute trips would also not occur. Consequently, it is not expected that PR 1304.1 would increase the number of passenger vehicle and/or heavy-duty truck trips or exceed any level of service standards. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
13. Would the proposed project have the potential to physically divide an established community or conflict with an applicable land use plan, policy or regulation of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental affect?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation and would not require any physical changes at the affected facilities. Therefore, the proposed project does not have the potential to physically divide an established community. There are no provisions in the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments, and no land use or planning requirements would be directly or indirectly altered by the proposed project. Therefore, there would be no direct or indirect impacts on land use and planning. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
14. Would the proposed project result in the loss of forest land or conversion of forest land to non-forest use or conflict with existing zoning for forest land or timberland?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. The proposed project would be consistent with the heavy industrial zoning requirements for the various facilities and there are no forestry resources or operations on or near the affected EGFs. Thus, PR 1304.1 would not conflict with existing zoning for forest land or timberland, nor would it result in the loss of forest land or conversion of forest land to non-forest use. This environmental topic will not be further evaluated in the Draft EA.

	Yes	No
15. Would the proposed project increase the use of existing neighborhood and regional parks or other recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. The proposed project would be consistent with the heavy industrial zoning requirements for the various facilities and there are no recreational facilities on or near the affected EGFs. Thus, PR 1304.1 would not increase the use of existing neighborhood and regional parks or other recreational facilities. Further, the proposed project would not require the construction of new or expansion of existing recreational facilities. Based upon these considerations, significant recreation impacts are not expected from implementing the proposed project, and thus, this topic will not be further evaluated in the Draft EA.

	Yes	No
16. Would the proposed project create a significant hazard to the public or the environment through the routine transport, use, and disposal of hazardous materials or through reasonably foreseeable upset conditions involving the release of hazardous materials into the environment?	☐	☑

Discussion: The proposed project would require any EGF that uses a specific offset exemption to pay annual fees or a single, up-front fee for the amount of offsets provided by the SCAQMD. PR 1304.1 primarily affects existing facilities that have already been constructed and are in operation. Thus, PR 1304.1 would not increase the routine transport, use, and disposal of hazardous materials already in use at the existing facilities. Further, the proposed project would not change the existing hazards profile at the affected facilities in a way that would affect potential upset conditions. Based upon these considerations, significant hazards and hazardous materials impacts are not expected from implementing the proposed project, and thus, this topic will not be further evaluated in the Draft EA.

	Yes	**No**
17. Would the proposed project have the potential to degrade the quality of the environment, have potential impacts that are individually limited, but cumulatively considerable, or have potential environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☑	☐

Discussion: As indicated in the environmental checklist responses in the preceding sections, the public commented that potential project-specific impacts to air quality and energy may occur. Specifically, the SCAQMD has received comments from stakeholders asserting that implementing fees pursuant to PR 1304.1 would deter investment in replacing 50+ year old boilers with new more efficient gas turbines or other more efficient gas turbines, etc. The concern is that, as a result, because of potential transmission constraints and increased local reliability needs, there would be an increase in boiler emissions. The Draft EA will analyze whether a delay in replacing older boilers would occur and if a delay would have an impact on the electricity supply system. Additionally, the Draft EA will evaluate whether the potential for the San Onofre Nuclear Generating Station (SONGS) extended power outage would be an exacerbation of any impact.

Any fees collected pursuant to PR 1304.1 would be invested in air pollution improvement strategies for the pollutants for which the fee is paid, or their precursors or criteria pollutants to which they contribute, consistent with the needs of the 2012 AQMP.

APPENDIX A (OF THE NOP/IS)

PROPOSED RULE 1304.1 – ELECTRICAL GENERATING FACILITY ANNUAL FEE FOR USE OF OFFSE EXEMPTION

PROPOSED RULE 1304.1. ELECTRICAL GENERATING FACILITY ANNUAL FEE FOR USE OF OFFSET EXEMPTION

(a) Purpose and Applicability

The purpose of this rule is to require Electrical Generating Facilities (EGFs) which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the AQMD. Offsets in AQMD internal accounts are valuable public goods. The purpose of this rule is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304(a)(2). The fees will be invested in air pollution improvement strategies for the pollutants for which the fee is paid, or their precursors or criteria pollutants to which they contribute, consistent with the needs of the Air Quality Management Plan. This rule applies to all EGFs that use the offset exemptions described in Rule 1304(a)(2). Notwithstanding Rule 1301(c)(1), this rule applies to all permits issued to EGFs electing to use Rule 1304(a)(2) and receiving the applicable permit to construct on or after March 1, 2013.

(b) Definitions

(1) ELECTRICAL GENERATING FACILITY (EGF) means a facility that generates electricity for distribution in the state grid system, regardless of whether it also generates electricity for its own use or for use pursuant to a contract.

(2) COMMENCEMENT OF OPERATION means to have begun the first fire of the unit(s), or to generate electricity for sale, including the sale of test generation.

(c) Requirements

(l) Any EGF operator electing to use the offset exemptions provided by Rule 1304(a)(2) shall pay a fee, the Offset Fee (F_i), calculated pursuant to paragraph (c)(2), for each pound per day of each pollutant (i), for which the AQMD provides offsets. This fee may be paid on an annual basis or as a single payment at the election of the applicant.

(2) The Offset Fee (F_i), for a specific pollutant (i), shall be calculated by multiplying the applicable pollutant specific Annual Offset Fee Rate (R_i) or Single Payment Offset Fee Rate (L_i) and Offset Factor in Table A1 or A2, as applicable, by the fraction of the potential to emit level(s) of the new replacement unit(s) (PTE_{rep}), which is calculated as the maximum rated capacity (MWh) of the new replacement unit(s) minus the most recent twenty-four (24) months average of the capacity factor (megawatt utilization) of the unit(s) to be replaced divided by the maximum rated capacity (MWh) of the new replacement unit(s), in accordance with the following equations:

Annual Payment Option

$$\boldsymbol{Annual}\ Payment\ Offset\ Fee\ (F_i) = \boldsymbol{R_i} \times PTE\boldsymbol{rep}_{\cancel{irep}} \times OF_i \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Single Payment Option

$$\boldsymbol{Single}\ Payment\ Offset\ Fee\ (F_i) = \boldsymbol{L_i} \times PTE\boldsymbol{rep}_{\cancel{irep}} \times OF_i \times \left(\frac{C_{rep} - C_{2YRAvgExisting}}{C_{rep}}\right)$$

Where;

F_i	=	Offset Fee for pollutant (i).
R_i	=	Annual Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, (see Table A1 or Table A2, as applicable, for rates).
L_i	=	Single Payment Offset Fee Rate for pollutant (i), in terms of dollars per pound per day, (see Table A1 or Table A2, as applicable, for rates).
PTE_{rep}	=	permitted potential to emit of new replacement unit(s) for pollutant i, in pounds per day. (Maximum permitted monthly emissions ÷ 30 days).

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OF_i	=	offset factor pursuant to Rule 1315(c)(2) for extreme non-attainment pollutants and their precursors, (see Table A1 or A2, as applicable, for factors).
C_{rep}	=	maximum permitted annual megawatt capacity (MWh) of the new replacement unit(s). (Maximum rated capacity (MW) x Maximum permitted annual operating hours (h)).
$C_{2YRAvgExisting}$	=	the average annual megawatt-hour (MWh) generation of the existing unit(s) to be replaced using the last twenty-four (24) month period immediately prior to submittal of the permit to construct.

Table A1: Pollutant Specific Offset Fee Rates & Offset Factors applicable to the first 100MWs repowered at an EGF after March 1, 2013 with offsets debited from the AQMD internal accounts[1]

Pollutant (i)	**Annual** Offset Fee Rate (**R_i**) ($per lb/day)*	**Single Payment** Offset Fee Rate (**L_i**) ($ per lb/day)	Offset Factor (OF_i)
PM	$1,993	$49,822	1.0
NOx**	$1,332	$33,286	1.2
SOx	$1,585	$39,631	1.0
VOC	$93	$2,318	1.2

*Offset Fees paid annually and adjusted annually by the CPI, consistent with the provisions of Rule 320

**For non-RECLAIM sources only

[1] Proposed revision to Annual and Single Payment Offset Fee Rates under consideration.

Table A2: Pollutant Specific Offset Fee Rates & Offset Factors applicable to the balance of > 100MWs repowered at an EGF after March 1, 2013 with offsets debited from the AQMD internal offset accounts[2]

Pollutant (i)	**Annual** Offset Fee Rate (**R_i**) ($per lb/day)*	**Single Payment** Offset Fee Rate (**L_i**) ($ per lb/day)	Offset Factor (OF_i)
PM	$3,986	$99,643	1.0
NOx**	$2,663	$66,571	1.2
SOx	$3,170	$79,262	1.0
VOC	$185	$4,635	1.2

*Offset Fees paid annually and adjusted annually by the CPI, consistent with the provisions of Rule 320

**For non-RECLAIM sources only

(3) The owner/operator of an EGF electing to use the offset fee exemption of Rule 1304(a)(2) shall remit the offset fees as follows:

(A) For the annual payment option:

(i) the first year annual payment corresponding to the first year of operation must be remitted prior to the issuance of the permit to construct. Subsequent payments shall be remitted annually, on or before the anniversary date of the commencement of operation, beginning with the second year of operation.

(ii) If the owner/operator of an EGF fails to pay the applicable Annual Offset Fee (F_i) amount, for each applicable pollutant (i), within thirty (30) days after the due date, the associated permit(s) will expire and no longer be valid. Such permit may be reinstated within sixty (60) days with an additional penalty of 50%.

(B) For the single payment option, the entire fee must be remitted prior to issuance of the permit to construct. The owner/operator of an EGF that elects the annual fee payment option has the right to switch to

[2] Proposed revision to Annual and Single Payment Offset Fee Rates under consideration.

the single payment option by remitting the balance of the full single payment prior to the commencement of the second year of operation.

(4) Offsets provided under the provisions of this rule to a facility are not any form of property, and may not be sold, leased, transferred, or subject to any lien, pledge, or voluntary or involuntary hypothecation or transfer, and shall not be assets in bankruptcy, for purposes of taxation, or in any other legal proceeding.

(5) Refunds of First Year of Annual Payment or Single Payment

The full amount of any payments made in satisfaction of the requirements of the rule shall be refunded if a written request by the facility owner/operator is received prior to the commencement of operation. Such a request for refund shall automatically trigger cancellation of the Permit to Construct and/or Operate.

(d) Use of Offset Fee Proceeds

(1) Except as provided in Paragraph (d)(2), the Offset Fee proceeds paid pursuant to this rule shall be deposited in an AQMD restricted fund account and shall be used to obtain emission reductions consistent with the needs of the Air Quality Management Plan.

(2) Up to 8% of the Offset Fee proceeds, deposited in a restricted fund account, may be used by the Executive Officer to cover administrative costs related to this rule.

(e) Severability

If any provision of this rule is held by judicial order to be invalid, or invalid or inapplicable to any person or circumstance, such order shall not affect the validity of the remainder of this rule, or the validity or applicability of such provision to other persons or circumstances. In the event any of the exceptions to this rule is held by judicial order to be invalid, the persons or circumstances covered by the exception shall instead be required to comply with the remainder of this rule.

DRAFT

APPENDIX C

COMMENT LETTERS ON THE NOP/IS AND RESPONSES TO COMMENTS

A Notice of Preparation / Initial Study (NOP/IS) was circulated for a 30-day public review and comment period beginning on April 9, 2013 and ending May 8, 2013. The NOP/IS identified potentially significant environmental impacts from Proposed Rule 1304.1. The NOP/IS included the project background, project description, and an environmental checklist section that adequately evaluated all environmental topic areas outlined in Appendix G of the CEQA Guidelines.

The SCAQMD received two comment letters on the NOP/IS during the public comment period. The comment letters and responses to the comments raised in those letters are provided in this appendix of the Draft EA. The comments are bracketed and numbered. The related responses are identified with the corresponding number and are included following each comment letter.

Comment Letter #1
(Broiles & Timms, LLP, May 7, 2013)

BROILES & TIMMS, LLP

445 SOUTH FIGUEROA STREET, 27TH FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828

STEVEN A. BROILES
CHARLES F. TIMMS, JR.

May 7, 2013

<u>VIA EMAIL (JINABINET@AQMD.GOV) AND U.S. MAIL</u>

Jeffrey Inabinet
c/o Planning - CEQA
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comment Letter on Initial Study for Proposed Rule 1304.1 (revised draft 4/11/13); Cities of Burbank, Glendale and Pasadena

Dear Mr. Inabinet:

The Cities of Burbank, Glendale and Pasadena ("the Cities") hereby submit this comment letter on issues relevant to the environmental analysis for Proposed Rule ("PR") 1304.1 (revised draft 4/11/13). The District's Notice of Preparation and Initial Study for PR 1304.1, published on April 5, 2013, were accompanied by PR 1304.1 (revised draft 3/28/13). On April 11, 2013, the District revised the proposed rule and made changes to the proposed mitigation fee applicable to a boiler replacement project. Our comments address this most recent revision to PR 1304.1 (revised draft 4/11/13). 1-1

In prior correspondence commenting on PR 1304.1, the Cities raised potential environmental issues regarding the mitigation fee, both as originally proposed and as changed in the most recent version (revised draft 4/11/13). To sum up, the Cities pointed out that the proposed fee would make boiler replacement projects much more expensive and thus could lead to the delay, downsizing, or abandonment of these types of projects. This could result in increased emissions from the Cities' old, inefficient boilers and adverse impacts on local and Basin-wide electrical system reliability. The adverse system 1-2

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May 7, 2013
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reliability impacts and their potential environmental consequences deserve particular attention in view of the prospect for an extended outage at the San Onofre Nuclear Generating Facility ("SONGS"). A news report just last week even suggested that SONGS may have to be retired (Associated Press, May 1, 2013). In addition, local capacity reliability needs are increasing due to load growth and the delay in development of new transmission projects (California Energy Markets, May 3, 2013, No. 1230 at 16.1). The environmental assessment for PR 1304.1 must thoroughly analyze the potential environmental effects of these increased emissions and adverse system reliability impacts. 1-2 Cont.

- **Financial impacts on planned boiler replacement projects**

In their February 19, 2013, and February 22, 2013, comment letters, the Cities laid out the financial impact of the mitigation fee, as originally proposed, on hypothetical replacement projects. See February 19 letter at page 4 and Attachment 1; and February 22 letter at page 1 and Attachment 2. Further supporting backup data for these calculations were provided as attachments to a March 21, 2013, email memo. In that memo, the City of Glendale showed that if the replacement project had a capacity as large as the capacity of its current boilers, the proposed mitigation fee could cost about $40 million or 40% of the total project cost.

The District's revisions in the proposed mitigation fee (revised draft 4/11/13) would reduce these costs somewhat. As the Cities pointed out in their April 22 comment letter, changes in the proposed mitigation fee for projects less than 100 MW (the size of facility likely to be proposed by the Cities) reduce the likely financial impacts to about $14 million or 14% of the cost of a replacement project. See April 22 letter at page 2. While that is an improvement over the original proposal, mitigation fees at that level could still result in the delay, if not abandonment, of a replacement project. The cost of a replacement project would have to be balanced against the cost of operating and maintaining the old boilers combined with the cost of reduced local reliability. We cannot predict whether the delay would be five, ten or more years, but in the meantime the continued use of existing generation capacity would result in emissions rates at the rate of the old boilers, instead of the much lower rate of the replacement projects with up-to-date technology, and retail consumers would suffer reduced reliability, as the old boilers are expected to break down more often and for longer periods. Thus, the potential environmental and reliability impacts remain essentially the same as under the mitigation fee as originally proposed. 1-3

- **More emissions from the old, inefficient boilers**

In their February 19, 2013, and February 22, 2013, comment letters, the Cities also laid out the emissions impacts if boiler replacement projects are delayed, downsized or abandoned. The City of Burbank showed that anticipated emissions from their old boilers to provide power for peak summer demand are several times the emissions of a 1-4 replacement project. See February 19 letter at page 6 and Attachment 3. The City of Glendale similarly showed that anticipated emissions from their old boilers, most likely to provide power for peak summer demand, would substantially exceed emissions from a replacement project. See February 22 letter at page 2 and Attachment 4. The Cities provided additional supporting backup data for these calculations as attachments to the March 21, 2013, email memo. In that memo and attachments, the City of Glendale showed the increase in emissions that would result if the foregone replacement project had a capacity as large as the capacity of its current boilers. 1-4 Cont.

The environmental assessment for PR 1304.1 must thoroughly analyze the potential adverse impacts associated with these increased boiler emissions if the replacement projects are delayed, downsized or abandoned due to the mitigation fee imposed by PR 1304.1.

- **Less reliable electricity supply system**

In their February 19, 2013, comment letter and March 21, 2013, email memo, the Cities discussed the adverse impacts on local reliability for the Cities if they delay, downsize or abandon their planned boiler replacement projects. See February 19 letter at pages 6 and 7; and March 21 email memo.

In particular, as the Cities explain in their March 21 email memo, the Cities have limits on their ability to import energy from outside their service territories because each City has only one point of interconnection with the western electrical grid. The Cities need local generation to meet peak loads and to provide required reserves. Increasing loads (e.g., switching to electric vehicles and higher cooling demands associated with climate change) will require increasing amounts of local generating capacity, but the District's proposed mitigation fee will discourage the construction of that capacity. New transmission capacity cannot be assumed to be built for increased imports. Moreover, additional flexible, local generation is needed to integrate the increasing amounts of renewable power sources that are required by state law. 1-5

The environmental assessment for PR 1304.1 must thoroughly analyze the potential adverse impacts associated with the less reliable electrical supply system that will result if the boiler replacement projects are delayed, downsized or abandoned. These adverse impacts could include emissions from other, older generating capacity that is used because of the foregone replacement projects (including coal-fired generation), the environmental benefits that will be lost if renewable energy cannot be efficiently integrated into the system due to a shortage of local generating capacity, and potential adverse impacts resulting from electrical supply outages due to the lack of local generating capacity (e.g., potential shutdown of sewage treatment facilities with resulting adverse water quality impacts).

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Additional socioeconomic impacts resulting from degraded system reliability due to the foregone replacement projects also will need to be addressed in the socioeconomic analysis that is prepared for PR 1304.1. Lower reliability will lead to more frequent and longer outages, with socio-economic consequences. The Cities look forward to the opportunity to comment on that analysis. 1-5 Cont.

Please let us know if you have any questions. We appreciate the opportunity to provide these comments, and we look forward to continuing to participate in the rulemaking process, including review of the environmental assessment, and help the District Governing Board make a fully-informed decision on PR 1304.1.

Sincerely,

Charles F. Timms, Jr.

cc: Gurcharan Bawa (gbawa@cityofpasadena.net)
Lon Peters (lpeters@ci.glendale.ca.us)
Kim Yapp (kyapp@burbankca.gov)

Responses to Comment Letter #1
(Broiles & Timms, LLP, May 7, 2013)

1-1 The comment states that this comment letter is being submitted on behalf of the Cities of Burbank, Glendale and Pasadena. The comment also provides a brief summary of the schedule of the NOP/IS and identifies a revision to the proposed rule regarding a mitigation fee applicable to a boiler replacement project. The comment indicates that their comment letter addresses the most recent revision to the proposed rule (revised draft April 11, 2013). No further response to this comment is necessary.

1-2 The comment states that in prior correspondence, the Cities have raised potential environmental issues regarding the mitigation fee as originally proposed, as well as the most recent proposal (revised draft April 11, 2013). The comment states that the proposed fee would make steam boiler replacement projects more expensive and thus could lead to the delay, downsizing, or abandonment of these types of projects. These potential outcomes could result in increased emissions from the Cities' old, inefficient boilers and could cause adverse impacts on local capacity and Basin-wide electrical system reliability. The comment also indicates that an extended outage at the San Onofre Nuclear Generating Facility (SONGS) could exacerbate potential reliability and environmental impacts.

SCAQMD staff does not consider the proposed fee associated with the proposed rule for facilities that elect to use the SCAQMD's internal offset bank to be a "mitigation fee." The purpose of this proposed fee is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304 (a)(2), which they are currently getting free of charge from SCAQMD's internal accounts. Offsets in SCAQMD's internal accounts are valuable public goods. The fee is a reasonable cost for conferring the benefit of the offset, and it should be noted that proceeds of the fee will be invested in air pollution improvement projects that further the goals of the 2012 AQMP and reduce emissions of pollutants for which the fee is charged or their precursors or pollutants to which they contribute.

The SCAQMD acknowledges that the proposed fee may cause some facilities to possibly delay or adjust the schedule/parameters of steam boiler replacement projects. The SCAQMD also acknowledges that the shutdown of SONGS would need to be considered when evaluating reliability impacts. Any adverse impacts associated with these scenarios are analyzed in the Draft EA concluding that adequate measures are in place to prevent impacts on reliability.

1-3 The comment states that the Cities laid out the financial impact of the proposed fee as originally proposed, which would reportedly cost approximately 40 million dollars if the City of Glendale elected to conduct a replacement project as large as the capacity of their current boilers. The comment also states that with the most recent revisions to the proposed fee structure, the financial impact would be reduced to approximately 14 million dollars. The comment states that while this is an improvement, this level of a fee could still result in the delay, if not abandonment of a replacement project. Thus, the potential environmental and reliability impacts remain essentially the same as under the originally proposed fee.

SCAQMD staff has revised its proposal to make the fee structure less burdensome for potential replacement/repower projects. Additionally, several alternatives are analyzed in Chapter 5 of this Draft EA. Alternative A, the 'No Project' alternative, would result in no additional fee for any replacement/repower project. However, this alternative would not: 1) recoup the fair market value of offsets obtained from SCAQMD's internal account; 2) provide any funding for emission reduction projects; and, 3) further the goals outlined in the 2012 AQMP. The SCAQMD acknowledges that the proposed fee may cause some facilities to possibly delay or adjust the schedule and/or parameters of boiler replacement projects. Any adverse impacts associated with these alternatives are analyzed in Chapter 5 of this Draft EA.

SCAQMD staff has retained Dr. Frank A. Wolak, Director of the Program on Energy and Sustainable Development and Professor in the Department of Economics at Stanford University, to conduct an economic and reliability analysis on PR 1304.1, which further addresses any potential adverse impacts regarding electricity supply reliability and project delay concerns associated with this project. This report concludes that adequate measures are in place to prevent impacts on reliability and it would be unlikely that the currently proposed fee structure would cause potential repower projects to delay, downsize or abandon. Dr. Wolak's analysis can be found in Appendix D of this Draft EA.

1-4 The comment states that in previous correspondence, the Cities of Burbank and Glendale showed that anticipated emissions from their old boilers to provide power for peak summer demand are several times the emissions of a more efficient replacement project. The comment indicates that the environmental assessment must analyze potential adverse impacts associated with increased boiler emissions if the replacement projects are delayed, downsized or abandoned due to the fee imposed by PR 1304.1.

As stated previously, the SCAQMD has revised its proposal to make the fee structure less burdensome for potential replacement/repower projects. The purpose of the proposed fee is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304 (a)(2), which are currently free of charge from SCAQMD's internal accounts. However, SCAQMD staff acknowledges that the proposed fee may cause some facilities to possibly delay or adjust the schedule and/or parameters of boiler replacement projects. The potential adverse impacts associated with these scenarios are analyzed in depth in this Draft EA, with consideration for the worst-case increase in emissions. The analysis in the Draft EA compared maximum daily emissions averages of old boilers versus new gas turbines. The conclusion of this analysis is that, because the new gas turbines would operate more efficiently, a delay in repowering could potentially cause a delay in emission reductions. That delay concluded potential significant peak daily impacts to PM 10, VOC and NOx emissions. The details of this analysis can be found in Chapter 4 of the Draft EA.

1-5 The comment indicates that the Cities have limits on their ability to import energy from outside their service territories because there is only one point of interconnection with the western electrical grid. Increasing loads will require increasing amounts of local generation capacity, and the SCAQMD's proposed fee would discourage the construction of that capacity. The comment indicates that additional flexible, local generation is needed to integrate the increasing amounts of renewable power sources that are required by state law. Again, the commenter requests that the environmental assessment thoroughly analyze the potential adverse impacts associated with a less reliable electrical supply system that will result if the boiler replacement projects are delayed, downsized or abandoned. The commenter also indicates that many secondary impacts could also occur (e.g., environmental benefits list in renewable energy cannot be integrated, electrical supply outages resulting in the potential shutdown of sewage treatment facilities with resulting adverse water quality impacts, etc.). The commenter also indicates that the socioeconomic impacts resulting from degraded system reliability will also need to be analyzed.

As mentioned in Response to Comment 1-2, electrical system reliability concerns are addressed in the Draft EA. As previously mentioned in Response to Comment 1-3, a report has been prepared by Dr. Wolak that contains an economic and reliability analysis on PR 1304.1 concluding that adequate measures are in place to prevent impacts on reliability. SCAQMD staff believes this report addresses the concerns associated with any potential adverse impact from electricity supply reliability and project delay or downsizing as a result of implementing PR 1304.1. Dr. Wolak's analysis also indicates that it is unlikely that local supply generation capacity projects will be discouraged to be built due to the proposed fee. According to Dr. Wolak's report, "although municipal utilities are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and LTPP process. Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts. Copies of these documents are available on the web-sites of each of these municipal utilities." These mechanisms ensure that municipal utilities will have adequate generation capacity to meet their future demands and are able to pass of the costs to doing so to their consumers in retail rates. SCAQMD staff will also prepare a socioeconomic analysis under separate cover for the proposed rule.

Additionally, Dr. Wolak's report indicates that, "LADWP prepares an IRP annually with a 20-year timeframe to ensure that current and future energy needs of the City of Los Angeles are met. Similar to the CPUC LTPP, LADWP's IRP process lays out alternative strategies for meeting LADWP's energy supply and environmental policy goals, while maintaining a reliable supply of energy and minimizing the financial impact on their ratepayers. In its 2007 IRP, the City of Glendale considered at 10-year planning horizon and concluded that "GWP Has Sufficient Resources to Meet Expected Peak Loads Through the Period Covered by this IRP." In its 2006 IRP, BWP considered a 20-year planning horizon and concluded that "BWP plans to meet substantially all of its load growth requirements over the next 20 years with a combination of energy efficiency measures and renewable energy supplies."

Dr. Wolak's report also states that, "there are other state and local policies that are relevant to ensuring a reliable supply of electricity in California. One of these state policies specifically addresses cost recovery for repowering of existing generation units needed for local reliability. Local policies include the local reliability and long-term resource planning requirements set by municipal utilities to ensure they have adequate resources to meet current and future demand.

Assembly Bill 1576 specifies criteria under which the CPUC would approve a cost-of-service contract with an IOU that supports the repowering of an existing generation facility. Section 454.6, reproduced in the Appendix codifies these criteria, one of which is that the California ISO or local system operator certifies the project is needed for local reliability. Another criterion is that the repowering project complies with all applicable federal, state and local laws." Dr. Wolak's analysis and conclusions can be found in Appendix D of this Draft EA.

Comment Letter #2
(Southern California Public Power Authority, May 8, 2013)

SCPPA

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
1160 NICOLE COURT
GLENDORA, CA 91740
(626) 793-9364 – FAX: (626) 793-9461
www.scppa.org

ANAHEIM • AZUSA • BANNING • BURBANK • CERRITOS
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RIVERSIDE • VERNON • IMPERIAL IRRIGATION DISTRICT

May 8, 2013

Jeffrey Inabinet
c/o Planning - CEQA
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: SCPPA Comments on the Initial Study for Proposed Rule 1304.1- Electrical Generating Facility Annual Fee for Use of Offset Exemption

Dear Mr. Inabinet:

The Southern California Public Power Authority (SCPPA) would like to thank the South Coast Air Quality Management District (SCAQMD, or District) for this opportunity to provide comments on the Initial Study for Proposed Rule (PR) 1304.1 – Electrical Generating Facility Annual Fee for Use of Offset Exemption.

SCPPA is a joint powers authority consisting of eleven municipal utilities and one irrigation district. SCPPA members deliver electricity to approximately 2 million customers over an area of 7,000 square miles, with a total population of 4.8 million. SCPPAs members include the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside and Vernon, and the Imperial Irrigation District. 2-1

Many of our members have limits on their ability to import energy from outside their service territories because they have only one point of interconnection with the western electrical grid. Some SCPPA members require local generation to meet peak loads and to maintain required reserves. In addition, replacing aging boilers with more efficient, fast-start and fast-ramp equipment will better serve peak loads with lower emissions and aid in the integration of renewable energy resources. As such, it is important for these members, with aging steam boilers in their generation fleets, to be able to replace this existing capacity with cleaner, more efficient technology without the accompanying burdensome and unreasonable fees that may result in the delay or abandonment of these replacement projects.

I. COMMENTS ON THE INTIAL STUDY

SCPPA agrees with and supports the comments provided by the Cities of Burbank, Glendale, and Pasadena ("Cities") [1, 2] that the proposed fee would make their boiler replacement projects much

[1] SCPPA supports the comments submitted by Broiles & Timms, LLP on behalf of the Cities of Burbank, Glendale and Pasadena. 2-2

[2] The Los Angeles Department of Water and Power has no position on Proposed Rule 1304.1 at this time, nor a position on the Proposed Rule in the capacity as a member of SCPPA.

more expensive and thus could lead to the delay, downsizing, or abandonment of these types of projects. This could result in increased emissions from the member Cities' old, inefficient boilers and have adverse impacts on local and Basin-wide electrical system reliability.

SCPPA believes that the adverse system reliability impacts and their potential environmental consequences are regional in nature due to the aging generation fleet in Southern California, once-through cooling (OTC) regulations, load growth and delays in the development of new transmission projects. Given these factors, the Draft Environmental Assessment for PR 1304.1 must thoroughly analyze the potential environmental effects and adverse system reliability impacts caused by the proposed fee. SCPPA further recommends that any reliability studies conducted be coordinated with the affected balancing authorities in Southern California as well as the affected utilities with local generation and those contemplating the addition of local generation. 2-2 Cont.

A. Financial impacts on planned boiler replacement projects

The proposed fee represents a potentially significant cost to boiler replacement projects. As the Cities detailed in their prior comments and reiterated in their May 7, 2013 comments, the financial impact of the mitigation fee, as originally proposed could be about $40 million or approximately 40% of the project cost. With the recently proposed fee reduction, the cost would still be significant at approximately 14% of the cost of replacement projects. While that is an improvement over the original proposal, mitigation fees at that level could still result in the delay, if not abandonment, of a replacement project. The cost of a replacement project would have to be balanced against the cost of operating and maintaining the old boilers combined with the risk of reduced local reliability. 2-3

B. More emissions from the old, inefficient boilers

If the boiler replacement projects are delayed, downsized or abandoned, SCPPA members may have to operate their aging boilers to provide needed generation. As the Cities have shown in their prior comment letters to the District on this issue, the anticipated emissions from their old boilers to provide power for peak summer demand are several times the emissions of a replacement project. 2-4

The Draft Environmental Assessment for PR 1304.1 must thoroughly analyze the potential adverse impacts associated with these increased boiler emissions if the replacement projects are delayed, downsized or abandoned due to the mitigation fee imposed by the PR.

C. Less reliable electricity supply system

Most SCPPA members have limits on their ability to import energy from outside their service territories because they have only one point of interconnection with the western electrical grid. These Cities need local generation to meet peak loads and to maintain required reserves. Increasing loads (e.g., switching to electric vehicles and higher cooling demands associated with climate change) will require increasing amounts of local generating capacity, but the District's proposed mitigation fee will discourage the construction of that capacity. New transmission capacity cannot be assumed to be built for increased imports. Moreover, additional flexible, local generation is needed to reliably integrate the increasing amounts of renewable power sources that are required by state law. 2-5

II. CONCLUSION

The Draft Environmental Assessment for PR 1304.1 must thoroughly analyze the potential environmental effects and adverse system reliability impacts associated with the less reliable electrical supply system that will result if boiler replacement projects are delayed, downsized or abandoned. These adverse impacts could include emissions from other, older generating capacity that is used because of the foregone replacement projects (including coal-fired generation), the environmental benefits that will be lost if renewable energy cannot be efficiently integrated into the system due to a shortage of local generating capacity, and potential adverse impacts resulting from electrical supply outages due to the lack of local generating capacity (e.g., potential shutdown of sewage treatment facilities with resulting adverse water quality impacts). SCPPA further recommends that any reliability studies conducted be coordinated with the affected balancing authorities in Southern California as well as the affected utilities with local generation and those contemplating the addition of local generation. 2-6

Additional socioeconomic impacts resulting from degraded system reliability due to the foregone replacement projects also will need to be addressed in the socioeconomic analysis that is prepared for PR 1304.1. Lower reliability will lead to more frequent and longer outages, with socio-economic consequences. SCPPA looks forward to the opportunity to review and comment on that analysis.

Dated: May 8, 2013

Sincerely,

Oscar Herrera

By: Oscar Herrera
Interim Director of Regulatory Affairs
1160 Nicole Court,
Glendora, CA, 91740
Telephone Number: (626) 793 - 9362
Email: OHerrera@scppa.org

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Responses to Comment Letter #2
(Southern California Public Power Authority, May 8, 2013)

2-1 The comment provides a brief description of the Southern California Public Power Authority (SCPPA) which consists of eleven municipal utilities and one irrigation district. The comment states that many of their members have limits on their ability to import energy from outside their service areas and it is important for members to have the ability to replace aging boilers with cleaner, more efficient technology without the burden of unreasonable fees.

SCAQMD staff agrees that it is important for municipal utilities to have the ability to replace aging boilers with cleaner, more efficient technology. The purpose of the proposed fee is to recoup the fair market value of offsets procured by eligible EGFs electing to use such offsets to comply with Rule 1304 (a)(2), which are currently free of charge from SCAQMD's internal accounts. Offsets in SCAQMD's internal accounts are valuable public goods. The fee is a reasonable cost for conferring the benefit of the offsets, and it should be noted that proceeds of the fee will be invested in air pollution improvement projects that further the goals of the 2012 AQMP that reduce emissions of pollutants for which the fee is charged.

2-2 The comment states that the proposed fee would make boiler replacement projects more expensive and thus, could lead to the delay, downsizing, or abandonment of these types of projects. These potential outcomes could result in increased emissions from the affected cities' old, inefficient boilers and could cause adverse impacts on local and Basin-wide electrical system reliability. The comment also indicates that SCPPA believes that the adverse system reliability impacts and their potential environmental consequences are regional in nature due to the aging generation fleet in Southern California, once through cooling (OTC) regulations, load growth and delays in the development of new transmission projects. The comment also states that the Draft EA must thoroughly analyze the potential environmental affects and adverse system reliability impacts caused by the proposed fee.

SCAQMD staff acknowledges that the proposed fee may cause some facilities to possibly delay or adjust the schedule/parameters of boiler replacement projects. Potential adverse impacts associated with these scenarios are analyzed in the Draft EA. Additionally, as mentioned in Responses to Comments 1-3 and 1-5, the SCAQMD retained Dr. Frank A. Wolak, Director of the Program on Energy and Sustainable Development and Professor in the Department of Economics at Stanford University to conduct an economic and reliability analysis on PR 1304.1. Dr. Wolak's report concludes that adequate measures are in place to prevent impacts on reliability. According to Dr. Wolak's report, "Although municipal utilities, such at the Los Angeles Department of Water and Power (LADWP), City of Glendale Water and Power (GWP), and Burbank Water and Power (BWP) are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and LTPP process. Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts."

SCAQMD staff believes Dr. Wolak's report addresses any potential adverse impacts or reliability concerns associated with this proposed project. Dr. Wolak's analysis and conclusions can be found in Appendix D of this Draft EA.

With regard to the comment pertaining to the purpose of the proposed fee, see Response to Comment 2-1.

2-3 The comment states that the affected cities detailed the financial impact of the proposed fee as originally provided in earlier comments (on May 7, 2013), which would reportedly cost approximately 40 million dollars if the City of Glendale elected to conduct a replacement project as large as the capacity of their current boilers. The comment also states that with the most recent revisions to the proposed fee structure, the financial impact would be reduced to approximately 14 million dollars. The comment states that while this is an improvement, this level of a fee could still result in the delay, if not abandonment of a replacement project. Thus, the potential environmental and reliability impacts remain essentially the same as under the originally proposed fee.

SCAQMD staff has revised its proposal to make the fee structure less burdensome for potential replacement/repower projects. Additionally, several alternatives are analyzed in Chapter 5 of this Draft EA. Alternative A, the no project alternative, would result in no additional fee for any replacement/repower project. However, Alternative A would not provide any funding for emission reduction projects and would not further the goals outlined in the 2012 AQMP. The SCAQMD acknowledges that the proposed fee may cause some facilities to possibly delay or adjust the schedule and/or parameters of boiler replacement projects. The potential adverse impacts associated with these scenarios are analyzed in depth in this Draft EA, with consideration for the worst-case increase in emissions.

Additionally, as mentioned in Responses to Comments 1-3, 1-5, and 2-2, the SCAQMD retained Dr. Frank A. Wolak, Director of the Program on Energy and Sustainable Development and Professor in the Department of Economics at Stanford University to conduct an economic and reliability analysis on PR 1304.1. Dr. Wolak's report concludes that adequate measures are in place to prevent impacts on reliability. Additionally, Dr. Wolak's report indicates that, "in its 2007 IRP, the City of Glendale Water and Power (GWP) considered a 10-year planning horizon and concluded that "GWP Has Sufficient Resources to Meet Expected Peak Loads Through the Period Covered by this IRP." In its 2006 IRP, Burbank Water and Power (BWP) considered a 20-year planning horizon and concluded that "BWP plans to meet substantially all of its load growth requirements over the next 20 years with a combination of energy efficiency measures and renewable energy supplies." SCAQMD staff believes Dr. Wolak's report addresses the potential adverse impact regarding electricity supply reliability and project delay concerns associated with this proposed project. Dr. Wolak's analysis and conclusions can be found in Appendix D of this Draft EA.

2-4 The comment states that if the boiler replacement projects are delayed, downsized or abandoned, SCPPA members may have to operate their aging boilers to provide needed generation. The comment states that in previous correspondence, the Cities of Burbank and

Glendale showed that anticipated emissions from their old boilers to provide power for peak summer demand are several times the emissions of a more efficient replacement project. The comment indicates that the environmental assessment must analyze potential adverse impacts associated with increased boiler emissions if the replacement projects are delayed, downsized or abandoned due to the fee imposed by PR 1304.1.

With regard to the comment pertaining to the purpose of the proposed fee, see Response to Comment 2-1.

2-5 The comment indicates that most SCPPA members have limits on their ability to import energy from outside their service territories because there is only one point of interconnection with the western electrical grid. Increasing loads will require increasing amounts of local generation capacity, and the SCAQMD's proposed fee would discourage the construction of that capacity. The comment indicates that additional flexible, local generation is needed to integrate the increasing amounts of renewable power sources that are required by state law.

Local electrical system reliability concerns are addressed in this Draft EA and the analysis is supported by the conclusions in the report prepared by Dr. Frank A. Wolak (see Appendix D of this Draft EA).

2-6 The comment is a summary of all the points made throughout the comment letter. The comment repeats the suggestion that the Draft EA needs to thoroughly analyze the potential environmental effects and adverse system reliability impacts associated with a less reliable electrical supply system that will result if boiler replacement projects are delayed, downsized or abandoned. Additionally, the comment states that socioeconomic impacts could occur due to degraded system reliability caused by foregone replacement projects and that these impacts will need to be addressed. These issues and potential adverse impacts are analyzed in the Draft EA. In addition, a separate socioeconomic analysis will be prepared to address these concerns. See also Responses to Comments 2-1 through 2-5.

APPENDIX D

AN ECONOMIC AND RELIABILITY ANALYSIS OF THE PROPOSAL TO ASSESS A FEE TO ACCESS THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT'S OFFSET BANK BY DR. FRANK A. WOLAK

An Economic and Reliability Analysis of the Proposal to Assess a Fee to Access the South Coast Air Quality Management District's Offset Bank

by

Frank A. Wolak
Director, Program on Energy and Sustainable Development
Professor, Department of Economics
Stanford University
Stanford, CA   94305-6072

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1. Introduction

This report assesses the economic and electricity supply reliability consequences of the South Coast Air Quality Management District's (the District) proposal to assess a fee for existing owners of steam boilers in the District to access its offset bank for particulate matter (PM), nitrogen oxides (NO_x), sulfur oxides, (SO_x) and Volatile Organic Compounds (VOCs). Proposed Rule 1304.1 will require that all generation projects that replace an existing steam boiler in the District permitted subsequent to July 1, 2013 that elect to access the District's offset bank via the exemption in Rule 1304(a)(2) make a lump sum up-front payment or an annual payment based on the type of offset purchased and amount of offsets purchased.

The District has asked me to address three questions related to this proposed rule. First, to what extent, if any, will the proposed fees adversely impact the reliability of supply of electricity in the District and Southern California? Second, to what extent, if any, will the proposed fees deter the repowering of existing generation units using steam turbine technology with newer more energy-efficient units using combined cycle gas-turbine technology? Third, how are the costs of these fees paid by generation unit owners likely to be recovered from generation units and electricity consumers? The Appendix to this document provides a summary of my qualifications for making this assessment.

The remainder of this report proceeds as follows. Section 2 summarizes Proposed Rule 1304.1. Section 3 discusses the joint California Public Utilities Commission (CPUC) and California Independent System Operator's (ISO) Resource Adequacy (RA) program and the CPUC's Long-Term Procurement Plan (LTPP) process. The RA program ensures a reliable supply of electricity within the state during all hours of the coming year given the existing fleet of generation units and configuration of the transmission network. The LTPP process ensures that there is sufficient new generation capacity to meet the future demand for electricity in the state. This section discusses how the imposition of a fee for accessing the District's offset bank will interact with the local RA requirements and LTPP process in Southern California. Section 4 discusses the extent to which reliability is likely to be degraded as a result of the adoption of Proposed Rule 1304.1. This section concludes that because of the combined CPUC and California ISO RA process, the CPUC LTPP process, and several other state and local policies, Proposed Rule 1304.1 is unlikely to have any discernible impact on the reliability of the supply of electricity within the state. Section 5 analyzes how the amount of repowering of generation units in the District is likely to be impacted by the proposed rule. This section analyzes several hypothetical generation unit repowering investment decisions designed to be representative of conditions facing existing generation unit owners in the District in order to assess the impact of these proposed fees on their repowering decision-making process. Section 6 discusses how the combined California ISO market and CPUC regulatory process is likely to allocate the cost of these fees among participants in the California market. Section 7 closes with a summary of my answers to the three questions posed.

2. Proposed Rule 1304.1

This section first describes the existing procedure for gaining access to the District's offset bank as well how to obtain functionally equivalent emissions reductions credits (ERCs).

The process used to fill the District's offset bank is then described and compared to the process of obtaining ERCs. ERCs, particularly those for PM10, have become increasingly expensive to obtain and provide an equivalent service to offsets from District's offset bank. Consequently, from the perspective of economic efficiency, requiring new units to purchase the costly ERCs necessary to build and operate a new facility in the District, but providing free access to the District's offset bank to existing steam boilers that repower may bias new investment decisions in favor of repowering existing steam boilers rather than constructing a lower cost new generation unit that may reduce the cost of serving load in the Southern California and increase the overall reliability of supply of electricity more than repowering an existing unit. Proposed rule 1304.1 aims to correct this potential bias by requiring entities eligible to obtain offsets from the District's bank to pay for them.

Rule 1304(a)(2) allows an existing generation unit owner in the District that replaced a steam boiler with a more efficient electricity generation technology with free access to the district's offset bank, even if the project entailed more offsets than the existing generation unit at that site required. Proposed Rule 1304.1 will require repowering projects that access the offset bank for additional emissions beyond those associated with their most recent two years of annual average hourly output to pay an annual or up-front fixed fee for these offsets. This fee is based on positive difference between the maximum rated capacity of the replacement units and the most recent 24-month average amount of generation capacity used by the existing units.

ERCs are typically obtained from existing emitters in the District investing in new technologies that can reduce their emissions in quantifiable ways or by simply ceasing their operations in the district. Both of these actions are likely to be costly. Moreover, data on recent transactions of ERCs also demonstrates that ERC prices have been volatile because of the uncertain supply of emissions reductions. Emissions offsets typically enter the District's offset bank through what are called orphan shutdowns. According to Rule 1315, an orphan shutdown "means any reduction in actual emissions from a permitted source within the District resulting from removal of the source from service and inactivation of the permit without subsequent reinstatement of such permit provided such reduction is not otherwise required by rule, regulation, law, approved Air Quality Management Plan Control Measure, or the State Implementation Plan and does not result in issuance of an ERC." The last clause of the sentence is noteworthy because it indicates that the same set of actions could result in the creation of an ERC. For this reason, pricing ERCs to new entrants, but not pricing access to the District's offset bank to existing steam boilers that repower could unnecessarily increase in the cost of producing electricity in the District.

Proposed Rule 1304.1 will put repowering projects in the District in a similar economic position to new generation units built in the District. In general, new generation unit entrants must purchase ERCs on the open market to offset their emissions of PM10, NO_x, SO_x and VOCs. The recent Sentinel natural gas-fired plant built by Competitive Power Ventures is one exception to this rule. Through a special provision in Assembly Bill 1318 this plant was able to obtain access to the District's offset bank for a fee. This appears to be a one-off event, and future new generation capacity entrants will need to purchase the necessary ERCs on the open market.

The following example illustrates how continuing to provide free access to the District's offset bank to existing steam boilers that repower and requiring new units to purchase expensive ERCs could lead to inefficient new generation investment and operating decisions in the District. Suppose that a new combined cycle natural gas turbine (CCGT) facility can be built in the District and connect to the bulk transmission network at location where there sufficient transmission capacity for it to run at an 85 percent annual capacity factor. This plant may not be built because of the cost of purchasing ERCs, but instead an existing unit in the District may be repowered because it has free access to the District's offset bank, but because of where it is connected to transmission network there is only sufficient available transmissions capacity at that location for the repowered unit run at an annual capacity factor of 40 percent. If both units had to purchase the offsets needed to operate, the relative profitability of the two projects would imply that the existing unit would not repower, and instead the new unit would be built because of its much higher capacity factor. Moreover, the existing unit might even remain in operation to supply energy during the small number of hours of the year that it is needed because of a high demand for energy near its location.

Because, as shown in Section 5, the cost of acquiring the necessary ERCs to build a new generation unit is typically a small fraction of the fixed costs of the project, in most cases not requiring repowered units to pay for access to the district's offset bank and requiring new generation units to purchase ERCs may not result in the more expensive sources of electricity being built in the District. Nevertheless, this example illustrates several potential implications of proposed Rule 1304.1. First, it can lead to an overall lower cost and more reliable supply of electricity within the District because it reduces the up-front cost asymmetry between repowered and new generation projects. Second, it will discourage some generation units from repowering. Third, the decision not to repower the existing unit may both reduce the annual cost of serving load in the District and increase the reliability of the grid because a new more efficient generation unit is constructed in a less congested area of the transmission grid within the District.

Although the basic economic logic that charging existing generation units for access to the District's offset bank will cause some units not to repower cannot be denied, the next section explains that there are many more than adequate safeguards in place to ensure that grid reliability will not be adversely impacted by this decision. This section summarizes the important features of the joint California Independent System Operator (ISO) and California Public Utilities Commission (CPUC) resource adequacy process and the CPUC's long-term procurement policy. Section 4 then describes how Proposed Rule 1304.1 will be dealt with in the context of the resource adequacy process and why it will have no discernible adverse impact on system reliability in the District.

3. Ensuring a Reliable Supply of Electricity in California

The section summarizes important features of the joint California ISO and CPUC resource adequacy (RA) process, the CPUC LTPP process, and other state and local polices that ensure a reliable supply of electricity. Both the RA process and LTPP process are forward-looking in the sense that load-serving entities must contract in advance with generation unit owners to ensure there is adequate generation capacity within the state to meet future electricity demand. The RA process focuses on the year-ahead time horizon and specifies both local and system-wide generation capacity requirements. The LTPP focuses on ensuring that the utilities can meet their future demand for electricity by requiring the retailers to maintain a reserve margin of generation capacity above their anticipated demand and implement a long-term (ten-year) integrated transmission and generation planning process. The CPUC allows all approved of the costs of procuring RA capacity and new generation capacity built and long-term contracts signed through the LTPP process to be passed on in retail electricity prices to final consumers.

3.1. Resource Adequacy Process

The CPUC adopted a resource adequacy (RA) framework in response to California Public Utility Code Section 380 (which was added by Assembly Bill 380) to formalize a regulatory mechanism to ensure the reliability of supply of electricity in California. The CPUC established RA capacity requirements for all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs). Section 380 is reproduced in the Appendix to this report.

Section 380(c) states "Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service." It is important to note that Section 380 does not suggest a trade-off between cost and reliability. Maintaining a reliable supply electricity is the primary goal of Section 380.

Section 380 also ensures that all load-serving entities within the state satisfy these RA requirements. Section 380(e) states that, "The commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner. Each load-serving entity shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations pursuant to this section, or otherwise required by law, or by order or decision of the commission. The commission shall exercise its enforcement powers to ensure compliance by all load-serving entities." The provision ensures that all load-serving entities serving a given geographic area, such as the District, must comply with the same RA requirements.

In discussing how the cost of meeting these RA requirements will be met, Section 380(g) states

> An electrical corporation's costs of meeting resource adequacy requirements, including, but not limited to, the costs associated with system reliability and local area reliability, that are determined to be reasonable by the commission, or are otherwise recoverable under a procurement plan approved by the commission pursuant to Section 454.5, shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made, on a fully non-bypassable basis, as determined by the commission. The commission shall exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community

> choice aggregator or from customers that purchase electricity through a direct transaction pursuant to this subdivision.

This section clearly states that if the costs of the RA procurement are deemed prudent by the CPUC, then the LSE is entitled for full cost recovery in the retail prices it charges.

The RA program has two distinct requirements: System RA and Local RA. LSEs are required to make System RA Filings both annually and monthly, whereas they must only make Local RA Filings annually. Each LSE's System RA requirement is 115 percent of its total forecast load. Each LSE must also file information with the CPUC demonstrating procurement of sufficient Local RA resources to meet their RA obligations in transmission constrained Local Reliability Areas. These Local Reliability Areas are determined by the California ISO based on its assessment of the major transmission constraints in its control area.

Each year, the RA program requires LSEs to submit a Year-Ahead filing due two months before the start of the compliance year and twelve Month-Ahead filings during the compliance year. The RA procurement targets are based on demand forecasts submitted by the LSE and validated by the California Energy Commission (CEC). The CEC can make what are called "plausibility adjustments" to the LSE's annual and monthly load forecasts based on information it has at its disposal to ensure that system demand for that LSE will be met throughout the compliance year.

LSEs that do not fully comply with the RA program requirements can be issued citations or are subject to enforcement actions by the CPUC. The CPUC has issued some citations in the past for violations, but to date these have been modest because of the high level of compliance with the RA requirements.

Key to this high level of compliance is the significant involvement of the California ISO technical staff and its stakeholder process in the design and specification of System and Local RA requirements. Each year the California ISO takes the CEC-validated demand forecasts provided by each LSE and performs a Local Capacity Technical Study which forms the basis for the CPUC's System and Local RA procurement requirements for each Local Reliability Area, which are then apportioned to each LSE in California.

Because both the generation technology employed and where the unit is located impacts its ability to deliver a reliable supply of electricity to a given location in the grid, the RA process has developed a concept called the Net Qualifying Capacity (NQC) of a generation unit, which is the amount of a resource's capacity that can be counted for RA compliance filings. For example, because the typical wind generation unit in California is typically able to produce at an annual capacity factor in the range of 0.25, but a number of natural gas-fired units in the state produce at annual capacity factors greater than 0.80, the Qualifying Capacity (QC) of a wind unit is a significantly smaller fraction of the nameplate capacity than the QC of a natural gas-fired generation unit. Because deliverability of the energy produced by a generation resource to final electricity consumers is also an important factor determining a reliable supply of electricity, the QC of a given generation unit is further adjusted downward to reflect the deliverability of the energy produced. The California ISO adjusts the QC of a resource for its deliverability to obtain the NQC for the resource that is eligible to sell RA capacity. The CPUC then posts on its website the NQC for each resource that is eligible to sell RA capacity to CPUC jurisdictional LSEs.

The CAISO allocates transmission capacity for imports to CPUC jurisdictional and non-CPUC jurisdictional LSEs annually for the RA process. The California ISO follows a 13-step process to perform this allocation. Historically, California obtains approximately a one-quarter of its energy from imports, so this aspect of the RA process is crucial to maintaining a reliable supply of energy in California.

Historically, California met a portion of its local reliability generation needs with reliability must-run (RMR) contracts. Units with RMR contracts received this designation because they were required to operate at times when the market prices did not provide sufficient compensation for them to operate. Specifically, an RMR unit might have a variable cost of $60/MWh but relevant short-term market price was only $50/MWh, yet the unit was still needed to operate to maintain a reliable supply of electricity. An RMR contract was provided to the generation unit to provide sufficient revenue to remain available to supply energy when local reliability constraints require it.

RMR generation resources fell into two classes: Condition 1 contracts where the generation unit is only guaranteed partial annual cost recovery and was therefore allowed to sell into ISO markets if the unit was not dispatched by the California ISO to meet a reliability need, and Condition 2 units that were guaranteed full cost recovery but are not allowed sell into ISO markets even the unit was not dispatched for reliability purposes. The full cost of both types of RMR contracts were paid for by all final electricity consumers in the transmission area.

Consistent with CPUC policy, Local RA began to replace RMR contracts for the 2007 compliance year. There has been a decline in RMR designations since that time. However, the recent shutdown and planned retirement of the San Onofre Nuclear Generating Station (SONGS) has caused the California ISO to enter into an RMR contract with the Huntington Beach Units 3 and 4 owned by AES Corporation. These units had not operated since October of 2012 because the emissions permits required by the District to operate them were transferred to Edison Mission as part of a separate sale and leaseback transaction. To address reliability concerns caused by the shutdown of SONGS, the California ISO designated Units 3 and 4 as RMR units, and entered into an RMR agreement with the owner of the units under which they will provide reactive power and voltage support for the 2013 contract year. Like other RMR contracts, the cost of this contract will be recovered from customers in the local area that benefits from the services they provide. This recent RMR designation of the two formerly closed Huntington Beach units by the California ISO demonstrates the wide-ranging discretion the current joint California ISO and CPUC RA process has to ensure a reliable supply of energy.

A final compliance issue with the RA process is the price paid by LSEs for RA capacity. Each year, the CPUC sets a waiver price for purchases of RA capacity. RA capacity purchased below this $/KW-year price follows an expedited process for being passed on to final electricity consumers. However, if a load-serving entity is unable to purchase capacity at or below this price, it can file for waiver with the CPUC to either not purchase the capacity or purchase the capacity at a higher price. The process for filing a waiver proceeds as follows. An LSE requesting a waiver must make such request at the time it files its Local RA compliance showing. According to CPUC decision, Decision 06-06-064 June 29, 2006, the waiver request must include both of the following:

(1) a demonstration that the LSE reasonably and in good faith solicited bids for its RA capacity needs along with accompanying information about the terms and conditions of the Request for Offer or other form of solicitation, and
(2) a demonstration that despite having actively pursued all commercially reasonable efforts to acquire the resources needed to meet the LSE's local procurement obligation, it either (a) received no bids, or (b) received no bids for an unbundled RA capacity contract of under the dollar per kW-year waiver price or for a bundled capacity and energy product of under dollar per kW-year waiver price, or (c) received bids below these thresholds but such bids included what the LSE believes are unreasonable terms and/or conditions, in which case the waiver request must demonstrate why such terms and/or conditions are unreasonable.

An LSE's waiver request that meets these requirements is a necessary but not a sufficient condition for the grant of such waiver. The Commission will also consider other information brought to its attention regarding the reasonableness of the waiver request. We find that administration of the ministerial aspects of this process may be delegated to our staff. For example, whether an LSE received any bids is an objective standard. On the other hand, whether proposed terms and conditions of a contract are reasonable is a question of judgment that must be reserved to the Commission. For such waiver requests, Energy Division should prepare a resolution for our consideration with its recommendations on whether the request should be approved or denied.

The final option available to meeting the joint CPUC and California ISO RA requirements is the California ISO's backstop provisions, which allows the California ISO to purchase RA capacity that it deems necessary under its Capacity Procurement Mechanism (CPM). Besides backstopping the RA program, the CPM also allows the California ISO to respond to a so-called significant reliability event. For example, the CPM sets a Federal Energy Regulatory Commission (FERC) regulated price for capacity for a pre-specified minimum duration of 30 days. In this way, reliability is maintained in the event that that a load-serving entity receives a waiver to purchase local RA capacity from the CPUC. If the ISO believes this capacity is needed to meet its RA requirements, it can issue a CPM designation for the generation unit and purchase its capacity at the FERC-regulated dollar per KW-year price for at least a 30-day period.

A significant event could also trigger a CPM designation for a generation unit or set of generation units.[1] In this case, the California ISO would determine that the significant event rendered its current RA procurement inadequate and it could issue a CPM designation for additional capacity to ensure that it has adequate RA capacity available to ensure a reliable supply of energy.

The availability of the CPM designation also serves as an effective price cap on what load-serving entities must pay for System and Local RA capacity. Because the California ISO has the option to issue a CPM designation and purchase the capacity on any generation in the control area at a FERC-regulated price for RA capacity for 30-days, this capacity price serves as

[1] Examples of significant events are given in the document, "Revised Draft Final Proposal: Capacity Procurement Mechanism, and Compensation and Bid Mitigation for Exceptional Dispatch," September 15, 2010, available at http://www.caiso.com/Documents/RevisedDraftFinalProposal15-Sep-2010.pdf

an effective price cap on the willingness of load-serving entities to sign RA contracts with generation units and in this way solves the final challenge of ensuring that the necessary RA capacity to ensure a reliable supply of electricity at all locations in California can be purchased at a reasonable price.

3.2. Long-Term Procurement Plan

Assembly Bill 57, passed in 2002, established Section 454.5 of the Public Utilities Code which requires the CPUC to hold a long-term procurement plan (LTPP) proceeding to review and approve the ten-year procurement plans of the three IOUs every two years. The LTPP proceeding evaluates the need of each of the three IOU's for new fossil fuel generation units, ensures that each IOU maintains an adequate generation reserve margin relative to their demand, and establishes rules for the recovery of long-term procurement costs from bundled and direct access customers in the IOU's service territory.[2] Section 454.5 of the Public Utilities Code is reproduced in the Appendix. The remainder of this section outlines the basic features of the LTPP process.

The LTPP process begins with each IOU formulating a forecast of its demand over the next ten years. The California Energy Commission's Integrated Energy Policy Reporting (IEPR) process produces the demand forecasts that form the basis for the demand forecasts used in the LTPP process. Each IOU then formulates resource plans for meeting these demand forecasts under a variety of transmission, generation retirement, energy efficiency, demand response, and renewable energy supply scenarios. Each IOU produces a recommended planning reserve margin (PRM) as part of its LTPP. Based on the results of these scenario analyses and the IOU's recommended PRM, each IOU proposes its new fossil fuel generation capacity needs for approval by the CPUC. The biannual LTPP process concludes with the CPUC approving plans for new fossil fuel capacity additions for each of the IOUs. The CPUC has also developed a cost allocation mechanism (CAM) as part of its LTPP process to allocate the cost of these new capacity additions that benefit both bundled and direct access customers located in the IOU's service territory. Essentially, the CAM ensures that direct access customers pay their share of the capacity cost associated with the capacity additions procured for system reliability.[3]

The CPUC LTPP process also established Procurement Review Groups (PRGs) to serve as an advisory group to review and assess the details of the IOU's overall procurement strategy as it is implemented. Activities overseen by the PRGs include: (1) the development of request for offers (RFOs) for new resources (generation capacity or long-term supply contracts), bid evaluation and ranking of the offers received from an RFO, (3) natural gas supply plans, (4) electricity and natural gas hedging strategies, (5) congestion hedging strategies, (6) nuclear fuel purchase plans, and (7) energy and ancillary procurement portfolio positions and transactions.

The CPUC LTPP also authorizes the IOUs to employ an Independent Evaluator (IE) to monitor competitive solicitations (RFOs) that involve affiliate transactions, IOU-built or IOU-

[2] Bundled customers are those that received electricity supply and transmission and distribution service from the IOU. Direct Access customers receive transmission and distribution service, but electricity supply from an alternative load-serving (LSE) entity.
[3] The Cost Allocation Mechanism (CAM) was adopted by the CPUC in Decision 06-07-029.

turnkey bidders. "The purpose of an IE in the RFO solicitation is to ensure a fair, competitive procurement process free of real or perceived conflicts of interest."[4] The CPUC also requires that an IE be used for all competitive RFOs that seek products of more than three months in duration. The IE submits a report to the CPUC in support of applications for capacity, energy and ancillary services purchased in competitive RFOs which the CPUC then uses to decide whether to allow the associated costs to passed on to final electricity consumers.

Section 454.5 states that the IOU's procurement plan eliminates the need for after-the-fact reasonableness reviews of actions in compliance with an approved procurement plan. In addition, the procurement plan will also ensure timely recovery of procurement costs incurred pursuant to an approved procurement plan. Section 454.5 also states that the IOU's rates will be set based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. These features of Section 454.5 ensure that costs incurred according to an approved LTPP will be recovered from electricity consumers.

3.3. *Other State and Local Policies*

There are other state and local policies that are relevant to ensuring a reliable supply of electricity in California. One of these state policies specifically addresses cost recovery for repowering of existing generation units needed for local reliability. Local policies include the local reliability and long-term resource planning requirements set by municipal utilities to ensure they have adequate resources to meet current and future demand.

Assembly Bill 1576 specifies criteria under which the CPUC would approve a cost-of-service contract with an IOU that supports the repowering of an existing generation facility. Section 454.6, reproduced in the Appendix codifies these criteria, one of which is that the California ISO or local system operator certifies the project is needed for local reliability. Another criterion is that the repowering project complies with all applicable federal, state and local laws.

Although municipal utilities, such at the Los Angeles Department of Water and Power (LADWP), City of Glendale Water and Power (GWP), and Burbank Water and Power (BWP) are not subject to CPUC oversight, these utilities also have similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA process and LTPP process. Each of these municipal utilities produces an Integrated Resource Plan (IRP) to meet future electricity demand in their service territory with a high level of reliability and while minimizing ratepayer impacts. Copies of these documents are available on the web-sites of each of these municipal utilities.

LADWP prepares an IRP annually with a 20-year timeframe to ensure that current and future energy needs of the City of Los Angeles are met. Similar to the CPUC LTPP, LADWP's IRP process lays out alternative strategies for meeting LADWP's energy supply and environmental policy goals, while maintaining a reliable supply of energy and minimizing the

[4] CPUC Decision 07-12-052, page 140.

financial impact on their ratepayers.[5] In its 2007 IRP, the City of Glendale considered at 10-year planning horizon and concluded that "GWP Has Sufficient Resources to Meet Expected Peak Loads Through the Period Covered by this IRP."[6] In its 2006 IRP, BWP considered a 20-year planning horizon and concluded that "BWP plans to meet substantially all of its load growth requirements over the next 20 years with a combination of energy efficiency measures and renewable energy supplies."[7]

4. Impacts of Proposed Rule 1304.1 Reliability of Electricity Supply in California

The Local and System RA process and the ISO's CPM backstop to purchase additional capacity to meet the California ISO control area's RA needs or to respond to a significant event will ensure that there are no discernible short-term reliability consequences associated with the imposition of Proposed Rule 1304.1. The CPUC's LTPP process ensures that adequate generation capacity will be available and paid for to avoid any long-term reliability consequences associated with Proposed Rule 1304.1. This does not mean that some existing generation unit owners might decide not to repower their units because of the additional cost of accessing the District's offset bank and instead new units are built within the District in order to ensure a reliable supply of electricity or upgrades of transmission paths into the District preclude the need to build new generation capacity into the District.

Several recent events illustrate the ability of the RA and LTPP processes to ensure a reliable supply of electricity in the District. The decision of the California ISO to designate the recently retired Huntington Beach Units 3 and 4 as RMR units illustrates the flexibility of the existing CPUC and California ISO resource adequacy process in ensuring that grid reliability will not be adversely impacted by the imposition of Proposed Rule 1304.1. Southern California Edison's 2014 Local Capacity Requirement study included scenarios that assumed the two SONGS generation units would be offline for 2014, anticipating the June 7, 2013 announcement that units would be retired.[8]

It is important to recognize that there are many factors that enter into the decision of an existing generation unit owner with steam boiler to repower the facility besides the cost of Proposed Rule 1304.1. California's 33% Renewables Portfolio Standard (RPS) implies that thermal generation units throughout the state are likely to produce less electricity annually and instead serve to provide energy when intermittent renewable resources are unable to supply energy to the grid. The fact that a number of plants in the District have already repowered or are in the process of repowering significantly reduces the economic viability of additional units to repowering, even in the absence of Proposed Rule 1304.1. The existence of these more efficient units in the District implies that these lower operating cost units will be competing to set the

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[5] The 2012 version of LADWP's IRP is available at https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-integratedresourceplanning/a-p-irp-documents?_adf.ctrl-state=u59zy2c2b_4&_afrLoop=273413983643000.
[6] Page ES-1 of "City of Glendate Water and Power Department 2007 Integrated Resource Plan," available at http://www.glendalewaterandpower.com/pdf/rpt_IRP_2007.pdf.
[7] Page b of "2006 Integrated Resource Plan, Electric System, Burbank Water and Power, available http://www.burbankwaterandpower.com/download/2006-IRP-for-BWP-Final-Report.pdf.
[8] See Proposed Decision of ALJ Gamson (Mailed 5/28/2013), "Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program.

price of wholesale electricity in Southern California a larger fraction of the hours of the year, which reduces the profitability of repowering an existing unit.

There are also reasons why an existing unit owner with a steam boiler might decide to repower the unit in spite of the cost of Proposed Rule 1304.1. The California State Water Board requires that all generation units in California comply with the United States Clean Water Act Section 316(b), which states that the location, design, construction and capacity of cooling water intake structures must reflect the best technology available to protect aquatic life. Most of the existing plants in the District use seawater and once-through cooling technology. The Clean Water Act requires a 93 percent reduction in the use of seawater by these generation units. Most of the plants are planning to modernize their equipment and will switch to air cooling systems. Some have chosen to use evaporative cooling towers. There are clear cost synergies associated with repowering a generation unit at the time the cooling tower is modernized, that may improve the economic case for repowering. However, it is important to emphasize that maintaining a reliable supply of electricity to California consumers is a major challenge to achieving these goals of the Clean Water Act. Early in the policy formulation process, the State Water Resources Control Board (SWRCB) commissioned a study of the reliability impacts of once-through-cooling mitigation. Finally, the policy ultimately adopted by the SWRCB states that these water use standards should be achieved without "disrupting the critical needs of the State's generation and transmission system."[9]

The recent decision of Southern California Edison to close SONGS will also likely improve the economic case for repowering because of the increased demand for energy in the LA Basin Local Reliability Area and the loss of 2,200 MW of installed nuclear capacity that typically ran at an annual capacity factor close to 0.90. However, a number of existing units may need to remain in service longer because of the retirement of the two SONGS units to facilitate the repowering and once-through-cooling mitigation at other generation units in the District.

Consequently, it is important to recognize the many factors that go into the decision to repower a generation unit. Nevertheless, it cannot be denied that charging existing units that repower steam boilers for accessing the District's offset bank may cause some unit owners to decide against repowering. However, because of the structure of the joint CPUC and California RA process, the CPUC LTPP process, and other state and local policies, this is extremely unlikely to reduce the reliability of supply of electricity in Southern California or the entire state. The next section presents some hypothetical calculations based on realistic market prices and production technologies to assess the sensitivity of an existing steam boiler unit owner's repowering decision to the cost of accessing the District's offset bank.

5. Economics of Repowering Generation Units and Proposed Rule 1304.1

This section considers several hypothetical repowering decisions to assess the extent to which the imposition of this fee to access the District's offset bank is likely to deter these investments. The variable profit stream of the repowered unit, including the cost of repowering, is compared to the variable profit-stream of maintaining the existing unit, including any annual fixed payments to keep the existing unit in operation. The unit owner can be expected to take

[9] http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/

whatever action yields the highest variable profits, assuming at least one of the actions yields positive variable profits. Otherwise, the unit owner can be expected to shut the unit down.

We consider a simple model of this decision-making to process to illustrate the sensitivity of this decision to the cost of accessing the District's offset bank. Let c_B equal the variable cost in dollars per MWh of producing electricity from the existing unit before it repowers. Let c_A equal the variable cost in dollars per of MWh of producing electricity from the unit after it repowers. The major cost component of c_A and c_B is the variable fuel cost which is equal to the heat rate (HR) of the generation unit in million BTU (MMBTU) per MWh times the price of the input fossil fuel (PF) in dollars per MMBTU. According to data provided to me by the District, the annual average heat rate of most of the existing steam boilers in the District is between 10 to 12 MMBTU per MWh. At a price of natural gas equal to $4/MMBTU (which is at the high end of recent delivered prices to Southern California), the variable fuel cost of a unit with a heat rate of 10 MMBTU/MWh is $40/MWh. Other components of the variable cost of production are the variable operating and maintenance (VOM) cost in the range of $2 to $4 per MWh and the variable cost of NO_X and CO_2 mitigation.[10] The contribution of each of these factors to the variable cost of producing electricity is equal to the emissions rate of the pollutant in tons per MWh times the price of an emissions allowance for that pollutant in dollars per ton. Summing up all of these components yields the variable cost of the generation unit in state of the world j which is equal to:

$$c_j = VOM_j + HR_j{*}Fuel\_PF + NOXR_j{*}PNOX + CO2R_j{*}PCO2 \text{ for } j = A \text{ and } B$$

where $NOXR_j$ is equal to the NO_x emissions rate for state of the world j, PNOX is the price of NO_x emissions allowances, $CO2R_j$ is equal to the emission for the unit in state of the world j, and PCO2 is the price of CO_2 emissions allowances.[11] If the generation unit is not a participant in the District's REgional CLean Air Incentives Market (RECLAIM) market for NO_x emissions, then this component of the variable cost of producing electricity is zero.

The major rationale for repowering an existing unit is to reduce the variable cost of producing energy by employing a more efficient technology. Employing a more energy-efficient technology for producing electricity also reduces the emission rates for NO_X and CO_2 mitigation per MWh of energy produced. Specifically, $HR_A < HR_B$ typically implies that $NOXR_A < NOXR_B$ and $CO2R_A < CO2R_B$ which implies that for a same price of an emissions allowance, the contribution of emissions allowance purchases to the variable cost of producing electricity is smaller for the more efficient unit. For example, according to information provided to me by the District, using modern combustion turbine technology can reduce the heat rate of a natural gas-fired generation unit to 8.5 MMBTU/MWh. According to information provided to me by the District, repowering the facility to employ combined-cycle gas turbine (CCGT) technology can reduce the average heat rate of the facility into the range of 6.5 to 7.2 MMBTU per MWh.

[10] The California ISO's Department of Market Monitoring using values variable operating and maintenance costs in this range to set the variable cost of natural gas-fired generation units in its local market power mitigation mechanism.

[11] Recall that since January 1, 2013 California has a cap and trade program for greenhouse gas (GHG) emissions for electricity consumed in the state. Allowance prices for CO_2 emission are currently trading in the range of $10/Ton.

Average NO_x and CO_2 emissions rates in tons per MWh are generally lower for the facilities with the lower heat rates.

Let F_A equal the fixed cost of repowering the generation unit and F_B the fixed cost of keeping the existing unit in working order. For simplicity let p equal the price paid for wholesale power. Let r equal the firm's annual opportunity cost of capital. The annual profit of the existing unit is equal to:

$$VP_B = (p - c_B)q_B - rF_B,$$

where q_B is equal to the firm's annual output if it does not repower. The first term is the variable profit earned by from selling wholesale electricity. It is equal to the price of wholesale power less the unit's marginal cost of production times the amount of output it produces. The second term is the unit's annual capital cost. The variable profit is the difference between these two terms. The variable profit of the repowered unit is equal to:

$$VP_A = (p - c_A)q_A - rF_A,$$

where q_B is equal to the firm's annual output before repowering. It is composed of the same two terms under the state of the world that the unit has repowered. Assuming both VP_A and VP_B are positive, the firm will repower the unit if VP_A - AC is greater than $VP_{B,}$ where AC is the annual cost of accessing the District's offset bank. This inequality implies that

$$(p - c_A)(q_A - q_B) + (c_B - c_A)q_B - r(F_A - F_B) - AC \text{ is positive.}$$

Dividing both sides, by q_A yields following expression for the decision to repower the boiler.

$$(p - c_A)[(q_A - q_B)/q_A] + (c_B - c_A)[q_B/q_A] - [r(F_A - F_B) + AC]/q_A > 0. \qquad (1)$$

As discussed above, the major motivation for repowering is to lower variable operating costs, so that we assume $c_A < c_B$. The lower variable cost of the repowered unit implies that it is also likely to produce more energy on annual basis because it will be dispatched more frequently produce energy.

Substituting realistic numbers for the parameters in equation (1) can allow an assessment of the impact of AC, the annual cost a repowered unit must pay for access to the District's offset bank. Based on current natural gas prices and the assumed emissions rates for NO_x and CO_2 emissions allowances a value of c_B equal to \$45/MWh is credible. Assuming that the unit is repowered to be a CCGT unit, these same prices of natural gas, and NO_x and CO_2 emissions allowances implies a value of c_A equal to \$30/MWh is credible. Suppose that as a result of repowering, the new unit produces twice as much per MW of capacity on an annual basis. This implies that $q_A = 2q_{B.}$ This could occur because the unit's capacity factor increases from 0.20 to 0.40 or 0.40 to 0.80. According to recent data, the cost of repowering a generation unit in the District is in the range of \$1,000,000 per MW.[12]

[12] The City of Pasadena Glenarm Generation Station repower project has an estimated cost \$115 million to repower a 71 MW facility. The Los Angeles Department of Water and Power repower of the Haynes Generation Station has an estimated cost of \$782 million to repower a 600 MW facility.

Suppose that repowering the facility increases the capacity factor from 0.40 to 0.80, which implies that a 1 MW facility would produce 0.8*(8760 hours)*(1 MW) = 7,008 MWh per year. Assume that the real cost of capital to the firm is 10 percent, so that r = 0.1 and that the price the unit is able to sell its output at, p, is equal to $55/MWh. For simplicity, assume that the going forward fixed cost of maintaining the existing unit is $300,000. Inserting this information into equation (1) and assuming AC = 0 yields:

$$(55 - 30)[0.5] + (45 - 30)[0.5] - [0.1(1{,}000{,}000 - 300{,}000)/7{,}008] = 20 - 10 = 10 > 0.$$

Therefore, if the cost of accessing the District's offset bank was zero, AC = 0, then repowering would maximize the profits of the unit owner.

This decision to repower would be largely unaffected by the presence of a substantial cost to access the District's offset bank. For example, in its January 22, 2013 Working Group Meeting #1 presentation entitled, "Proposed Rule 1304.1: Electrical Generation Facility Annual Fee for Use of Offset Exemption," the District estimates the annual dollar cost on a per MW of installed capacity for the 520 MW peaker facility considered in their example is approximately $5,000 per year.[13] Incorporating this annual cost, AC, into equation (1) yields

$$(55 - 30)[0.5] + (45 - 30)[0.5] - [0.1(1{,}000{,}000 - 300{,}000)+5{,}000]/7{,}008 = 9.29 > 0.$$

Even tripling this annual fee to $15,000 does not impact the decision to repower the unit. The efficiency gain in terms of switching from a heat rate of around 10 MMBTU/MWh to 7 MMBTU/MWh yields such a large increase in variable profits in spite of having to pay for the up-front cost of repowering the unit and annual fee to access the District's offset bank. Assuming that the annual fixed cost of continuing to operating the existing unit is zero, not $300,000, does not change any of the above three decisions to repower the unit.

Changing the firm's real cost of capital to 0.15 does not impact the firm's repower decisions at a zero or a $300,000 annual fixed cost of the existing unit at the estimated $5,000 annual cost of accessing the District's offset bank. Changing the capacity factor of the existing unit to 0.3 and the capacity factor of the new unit to 0.6 does not change either of these two repower decisions.

Where the annual fee to access the District's offset bank may have an impact on the decision to repower is when the economics of the repower project are barely in the money without the fee to access the District's offset bank. Specifically, if the efficiency of the new unit is close to the efficiency of the existing unit and the repowered unit is expected to operate with a similar capacity factor to the existing unit, repowering may not be profitable for the unit owner. However, these are simply the conditions which make the economics of repowering the unit challenging in the absence of a non-zero value for AC. An annual fee in the neighborhood of $5,000 per MW of installed capacity is unlikely to impact the economics of projects that are clearly in the money without the cost to access the District's offset bank.

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[13] Current fee in the June 18, 2013 version of Proposed Rule 1304.1 represents about a 50% reduction in this value, with a current annual dollar cost per MW of $2,900 (http://www.aqmd.gov/rules/proposed/1304-1/DR1304_1.pdf)

This simple model of an existing unit owner's decision to repower a steam boiler can be enhanced in a number of dimensions, but the basic conclusion is unlikely to change. For example, the average price paid for energy to the repowered unit could be assumed to be smaller than the average price paid to the existing unit because the repowered unit operates more hours of the year. Average prices during the high demand hours of the day, when existing unit is likely to operate, are higher than average prices for the larger number of hours of the day that the repowered unit is likely to operate. However, based on current California ISO day-ahead price data, the ratio of average prices during the peak hours of the day (when the existing unit is likely to operate) to average prices across all hours of the day (when the new more efficient unit is likely to operate) is not nearly as large as the ratio of the anticipated total annual output of the repowered unit divided by the actual total annual output of the existing unit. Therefore, the existing unit is likely to sell at a higher quantity-weighted average price relative to the repowered unit, but the repowered unit is likely to sell a much larger amount of output annually that more than makes up for selling at a slightly lower average price.

The basic conclusion of this modeling analysis is that for a wide range of repowering scenarios, charging a fee to access the District's offset bank at the level envisioned by the District in the most recent version of Proposed Rule 1304.1 is extremely unlikely to change the decision of an existing unit owner that had decided to repower the unit in the absence of Proposed Rule 1304.1. Consequently, the only remaining issue associated with assessing the economic and environmental impact of this rule change is how the fees to access the District's offset bank will be recovered by generation unit owners.

6. How Will Cost of Fees Be Recovered by Generation Unit Owners

This annual or up-front fee will be recovered the same way other up-front and annual fees are recovered by generation unit owners in the California ISO market. Because of the closing of SONGS, according to the California ISO's 2014 Local Capacity Technical Analysis, virtually all of the generation capacity in the LA Basin Local Reliability Area will be required to meet the joint CPUC and California local RA requirements for this region.[14] Consequently, a portion of the cost of the fee to access the District's offset bank will likely be recovered from the prices load-serving entities in Southern California pay for local RA capacity.

Generation unit owners typically sign fixed-price forward contracts for the vast majority of their expected energy output. As discussed in Section 3, if these contracts are consistent with the IOU's LTPP procurement strategy, then the revenue stream from these contracts can be used to recover both the up-front and annual fixed-costs and the variable cost of procuring this energy. Generation unit owners can also receive revenues from selling ancillary services such as regulation reserve, spinning reserve, and non-spinning reserve. Particularly, generation unit owners located near major load centers, such as many of the existing units in the District, can earn significant annual revenues from selling ancillary services. Under the terms of the California ISO tariff, the total cost of procuring the ancillary services needed to maintain a

[14] 2014 Local Capacity Technical Analysis, Final Report and Study Results, April 30, 2013, available at http://www.caiso.com/Documents/Final2014LocalCapacityTechnicalStudyReportApr30_2013.pdf

reliable supply of electricity in California are charged to all load-serving entities in proportion to the amount of energy they withdraw from the California ISO control area.

All these costs are passed on to retail electricity consumers in their retail prices. The cost of local RA capacity is passed on through the CPUC-regulated prices set for the retail electricity sales of CPUC-jurisdictional utilities. A similar process exists for other load-serving entities in the California ISO control area. As discussed in Section 3, the Cost Allocation Mechanism ensures that Direct Access load pays for the capacity cost associated new generation capacity built under the IOU's LTPP to meet a system reliability need. The fixed price forward contracts signed by generation unit owners and retailers hedge the risk of short-term wholesale price fluctuations that are consistent with the IOU's LTPP are also passed through in the retail prices paid by consumers. Other retailers must recover the costs of purchasing the capacity, energy and ancillary services necessary to serve their customers through the prices they charge.

Finally, to the extent that a generation unit is required to remain in the District and operate because of the ISO's local reliability requirements (not because it can earn sufficient revenues from selling its output at market-based prices), there is a provision in the California ISO tariff to allow it to pay the unit owner's annual total cost of operating and pass these costs on to electricity consumers through an uplift payment charged to all loads that benefit from the services this unit provides. This mechanism applies to the case of the RMR status designated for the Huntington Beach 3 and 4 units described earlier. The total cost of these units will be allocated to all loads in the California ISO control area. Finally, if new generation capacity is must be built to meet an anticipated local reliability need contained in the LTPP of an IOU, then this cost of this capacity will be recovered in the prices charged to both bundled and Direct Access customers.

In summary, the cost of this fee will be recovered from the market-based payments that the unit owner receives or through a cost-of-service base charge if it is providing these services through a RMR or other regulated energy or capacity service set through the ISO's tariff. These charges can also be recovered through a long-term contract for energy or new generation capacity procurement if the purchase is consistent with an IOU's LTPP.

7. Conclusion

Based on the above analysis, the District's Proposed Rule 1304.1 is highly unlikely to adversely impact the reliability of the electricity supply in Southern California or in the California ISO control area. The joint CPUC and California ISO resource adequacy process will ensure that the generation units needed to maintain a reliable supply of energy in the state are available. In addition, for virtually all of the cases that generation unit owner would decide to repower an existing steam boiler without having to pay for the access to the District's offset bank, the cost assessed to access the District's bank would not change the economics of this decision. Finally, the cost of this fee will be recovered from both the market-based and regulated services that suppliers in the District provide including local RA capacity, long-term contracts for energy, ancillary services, and regulated reliability services such as an RMR unit status or a CPM payment.

Appendix: Bio and Relevant Experience of Frank A. Wolak

Wolak is the Holbrook Working Professor of Commodity Price Studies in the Economics Department and the Director of the Program on Energy and Sustainable Development at Stanford University. He received his undergraduate degree from Rice University, and an S.M. in Applied Mathematics and Ph.D. in Economics from Harvard University. He specializes in the study of privatization, competition and regulation in network industries such as electricity, telecommunications, water supply, natural gas, and postal delivery services. Wolak's recent research has focused on design and monitoring of energy and environmental markets.

From April 1998 to April 2011, he was Chair of the Market Surveillance Committee (MSC) of the California Independent System Operator. In this capacity, he has testified numerous times at the Federal Energy Regulatory Commission (FERC), and at various Committees of the US Senate and House of Representatives on issues relating to market monitoring and market power in electricity markets. Topics addressed in this testimony include: FERC's role in the design of the California electricity market, the factors leading to the California electricity crisis, the role of the Enron trading strategies in the California electricity crisis, and lessons from the California electricity crisis and Enron bankruptcy for the design of effective regulatory oversight of wholesale energy markets.

Wolak has worked on the design and regulatory oversight of the electricity markets internationally in Europe in England and Wales, Italy, Norway and Sweden, and Spain; in Australia/Asia in New Zealand, Australia, Indonesia, Korea, and Philippines; in Latin American in Brazil, Chile, Colombia, El Salvador, Honduras, Peru, and Mexico; and the US in7 California, New York, Texas, PJM, and New England. He has contributed to the design of market monitoring protocols in a number of electricity markets. He was commissioned by the Colombian government to design an independent market monitoring committee for the Colombian electricity supply industry. He was commissioned by the Inter-American Development Bank to develop market monitoring protocols for the Central American electricity market. The Swedish competition authority commissioned him write a research report on the co-ordination of competition policy and electricity market monitoring in European countries. He worked on the design of market monitoring protocols for the Philippines electricity market. He was commissioned by the Brazilian electricity market operator to assess the performance of the short-term price determination process. He has recently completed a study commissioned by the New Zealand Commerce Commission on the state of competition in the New Zealand wholesale electricity market.

Wolak has worked on the design of transmission planning, expansion, and pricing protocols to enhance wholesale electricity competition and support the expansion of renewable energy resources in the United States and in the Australia, Canada, Chile, Peru, and the United Kingdom. He was involved in the development of the California ISO's Transmission Economic Assessment Methodology (TEAM) and recently completed a study for the Office of Gas and Electricity Markets (Ofgem) on the re-design of the transmission protocols for the United Kingdom electricity supply industry.

Wolak is currently a member of the Emissions Market Advisory Committee (EMAC) for

California's Market for Greenhouse Gas Emissions allowances. This committee advises the California Air Resources Board on the design and monitoring of the state's cap-and-trade market for Greenhouse Gas Emissions allowances.

Section 380 of California Public Utility Code

380. (a) The commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities.

(b) In establishing resource adequacy requirements, the commission shall achieve all of the following objectives:

(1) Facilitate development of new generating capacity and retention of existing generating capacity that is economic and needed.

(2) Equitably allocate the cost of generating capacity and prevent shifting of costs between customer classes.

(3) Minimize enforcement requirements and costs.

(4) Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.

(c) Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

(d) Each load-serving entity shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

(e) The commission shall implement and enforce the resource adequacy requirements established in accordance with this section in a nondiscriminatory manner. Each load-serving entity shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations pursuant to this section, or otherwise required by law, or by order or decision of the commission. The commission shall exercise its enforcement powers to ensure compliance by all load-serving entities.

(f) The commission shall require sufficient information, including, but not limited to, anticipated load, actual load, and measures undertaken by a load-serving entity to ensure resource adequacy, to be reported to enable the commission to determine compliance with the resource adequacy requirements established by the commission.

(g) An electrical corporation's costs of meeting resource adequacy requirements, including, but not limited to, the costs associated with system reliability and local area reliability, that are determined to be reasonable by the commission, or are otherwise recoverable under a procurement plan approved by the commission pursuant to Section 454.5, shall be fully recoverable from those customers on whose behalf the costs are incurred, as determined by the commission, at the time the commitment to incur the cost is made, on a fully non-bypassable basis, as determined by the commission. The commission shall exclude any amounts authorized to be recovered pursuant to Section 366.2 when authorizing the amount of costs to be recovered from customers of a community choice aggregator or from customers that purchase electricity through a direct transaction pursuant to this subdivision.

(h) The commission shall determine and authorize the most efficient and equitable means for achieving all of the following:

(1) Meeting the objectives of this section.

(2) Ensuring that investment is made in new generating capacity.

(3) Ensuring that existing generating capacity that is economic is retained.

(4) Ensuring that the cost of generating capacity is allocated equitably.

(5) Ensuring that community choice aggregators can determine the generation resources used to serve their customers.

(i) In making the determination pursuant to subdivision

(h), the commission may consider a centralized resource adequacy mechanism among other options.

(j) For purposes of this section, “load-serving entity” means an electrical corporation, electric service provider, or community choice aggregator. “Load serving entity” does not include any of the following:

(1) A local publicly owned electric utility.

(2) The State Water Resources Development System commonly known as the State Water Project.

(3) Customer generation located on the customer’s site or providing electric service through arrangements authorized by Section 218, if the customer generation, or the load it serves, meets one of the following criteria:

(A) It takes standby service from the electrical corporation on a commission approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class.

(B) It is not physically interconnected to the electric transmission or distribution grid, so that, if the customer generation fails, backup electricity is not supplied from the electricity grid.

(C) There is physical assurance that the load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation

Section 454.5 of California Public Utility Code

(a) The commission shall specify the allocation of electricity, including quantity, characteristics, and duration of electricity delivery, that the Department of Water Resources shall provide under its power purchase agreements to the customers of each electrical corporation, which shall be reflected in the electrical corporation's proposed procurement plan. Each electrical corporation shall file a proposed procurement plan with the commission not later than 60 days after the commission specifies the allocation of electricity. The proposed procurement plan shall specify the date that the electrical corporation intends to resume procurement of electricity for its retail customers, consistent with its obligation to serve. After the commission's adoption of a procurement plan, the commission shall allow not less than 60 days before the electrical corporation resumes procurement pursuant to this section.

(b) An electrical corporation's proposed procurement plan shall include, but not be limited to, all of the following:

(1) An assessment of the price risk associated with the electrical corporation's portfolio, including any utility-retained generation, existing power purchase and exchange contracts, and proposed contracts or purchases under which an electrical corporation will procure electricity, electricity demand reductions, and electricity-related products and the remaining open position to be served by spot market transactions.

(2) A definition of each electricity product, electricity-related product, and procurement related financial product, including support and justification for the product type and amount to be procured under the plan.

(3) The duration of the plan.

(4) The duration, timing, and range of quantities of each product to be procured.

(5) A competitive procurement process under which the electrical corporation may request bids for procurement-related services, including the format and criteria of that procurement process.

(6) An incentive mechanism, if any incentive mechanism is proposed, including the type of transactions to be covered by that mechanism, their respective procurement benchmarks, and other parameters needed to determine the sharing of risks and benefits.

(7) The upfront standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to execution of the transaction. This shall include an expedited approval process for the commission's review of proposed contracts and subsequent approval or rejection thereof. The electrical corporation shall propose alternative procurement choices in the event a contract is rejected.

(8) Procedures for updating the procurement plan.

(9) A showing that the procurement plan will achieve the following:

(A) The electrical corporation will, in order to fulfill its unmet resource needs and in furtherance of Section 701.3, until a 20 percent renewable resources portfolio is achieved, procure renewable energy resources with the goal of ensuring that at least an additional 1 percent per year of the electricity sold by the electrical corporation is generated from renewable energy resources, provided sufficient funds are made available pursuant to Sections 399.6 and 399.15, to cover the above-market costs for new renewable energy resources.

(B) The electrical corporation will create or maintain a diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products.

(C) The electrical corporation will first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.

(10) The electrical corporation's risk management policy, strategy, and practices, including specific measures of price stability.

(11) A plan to achieve appropriate increases in diversity of ownership and diversity of fuel supply of nonutility electrical generation.

(12) A mechanism for recovery of reasonable administrative costs related to procurement in the generation component of rates.

(c) The commission shall review and accept, modify, or reject each electrical corporation's procurement plan. The commission's review shall consider each electrical corporation's individual procurement situation, and shall give strong consideration to that situation in determining which one or more of the features set forth in this subdivision shall apply to that electrical corporation. A procurement plan approved by the commission shall contain one or more of the following features, provided that the commission may not approve a feature or mechanism for an electrical corporation if it finds that the feature or mechanism would impair the restoration of an electrical corporation's creditworthiness or would lead to a deterioration of an electrical corporation's creditworthiness:

(1) A competitive procurement process under which the electrical corporation may request bids for procurement-related services. The commission shall specify the format of that procurement process, as well as criteria to ensure that the auction process is open and adequately subscribed. Any purchases made in compliance with the commission-authorized process shall be recovered in the generation component of rates.

(2) An incentive mechanism that establishes a procurement benchmark or benchmarks and authorizes the electrical corporation to procure from the market, subject to comparing the electrical corporation's performance to the commission-authorized benchmark or benchmarks. The incentive mechanism shall be clear, achievable, and contain quantifiable objectives and standards. The incentive mechanism shall contain balanced risk and reward incentives that limit the risk and reward of an electrical corporation.

(3) Upfront achievable standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to the execution of the bilateral contract for the transaction. The commission shall provide for expedited review and either approve or reject the individual contracts submitted by the electrical corporation to ensure compliance with its procurement plan. To the extent the commission rejects a proposed contract pursuant to this criteria, the commission shall designate alternative

procurement choices obtained in the procurement plan that will be recoverable for ratemaking purposes.

(d) A procurement plan approved by the commission shall accomplish each of the following objectives:

(1) Enable the electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.

(2) Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.

(3) Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement plan. The commission shall establish rates based on forecasts of procurement costs adopted by the commission, actual procurement costs incurred, or combination thereof, as determined by the commission. The commission shall establish power procurement balancing accounts to track the differences between recorded revenues and costs incurred pursuant to an approved procurement plan. The commission shall review the power procurement balancing accounts, not less than semiannually, and shall adjust rates or order refunds, as necessary, to promptly amortize a balancing account, according to a schedule determined by the commission. Until January 1, 2006, the commission shall ensure that any over-collection or under-collection in the power procurement balancing account does not exceed 5 percent of the electrical corporation's actual recorded generation revenues for the prior calendar year excluding revenues collected for the Department of Water Resources. The commission shall determine the schedule for amortizing the over-collection or under-collection in the balancing account to ensure that the 5 percent threshold is not exceeded. After January 1, 2006, this adjustment shall occur when deemed appropriate by the commission consistent with the objectives of this section.

(4) Moderate the price risk associated with serving its retail customers, including the price risk embedded in its long-term supply contracts, by authorizing an electrical corporation to enter into financial and other electricity-related product contracts.

(5) Provide for just and reasonable rates, with an appropriate balancing of price stability and price level in the electrical corporation's procurement plan.

(e) The commission shall provide for the periodic review and prospective modification of an electrical corporation's procurement plan.

(f) The commission may engage an independent consultant or advisory service to evaluate risk management and strategy. The reasonable costs of any consultant or advisory service is a reimbursable expense and eligible for funding pursuant to Section 631.

(g) The commission shall adopt appropriate procedures to ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan, including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination, provided that the Office of Ratepayer Advocates and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission.

(h) Nothing in this section alters, modifies, or amends the commission's oversight of affiliate transactions under its rules and decisions or the commission's existing authority to investigate and penalize an electrical corporation's alleged fraudulent activities, or to disallow costs incurred as a result of gross incompetence, fraud, abuse, or similar grounds. Nothing in this section expands, modifies, or limits the State Energy Resources Conservation and Development Commission's existing authority and responsibilities as set forth in Sections 25216, 25216.5, and 25323 of the Public Resources Code.

(i) An electrical corporation that serves less than 500,000 electric retail customers within the state may file with the commission a request for exemption from this section, which the commission shall grant upon a showing of good cause.

(j)(1) Prior to its approval pursuant to Section 851 of any divestiture of generation assets owned by an electrical corporation on or after the date of enactment of the act adding this section, the commission shall determine the impact of the proposed divestiture on the electrical corporation's procurement rates and shall approve a divestiture only to the extent it finds, taking into account the effect of the divestiture on procurement rates, that the divestiture is in the public interest and will result in net ratepayer benefits.

(2) Any electrical corporation's procurement necessitated as a result of the divestiture of generation assets on or after the effective date of the act adding this subdivision shall be subject to the mechanisms and procedures set forth in this section only if its actual cost is less than the recent historical cost of the divested generation assets.

(3) Notwithstanding paragraph (2), the commission may deem proposed procurement eligible to use the procedures in this section upon its approval of asset divestiture pursuant to Section 851.

Section 454.6 of California Public Utility Code

454.6. (a) A contract entered into pursuant to Section 454.5 by an electrical corporation for the electricity generated by a replacement or repowering project that meets the criteria specified in subdivision (b) shall be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner determined by the commission to provide the best value to ratepayers.

(b) To be eligible for rate treatment in accordance with subdivision (a), a contract shall be for a project which meets all of the following criteria:

(1) The project is a replacement or repowering of an existing generation unit of a thermal power plant.

(2) The project complies with all applicable requirements of federal, state, and local laws.

(3) The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities.

(4) The project will result in significant and substantial increases in the efficiency of the production of electricity.

(5) The Independent System Operator or local system operator certifies that the project is needed for local area reliability.

(6) The project provides electricity to consumers of this state at the cost of generating that electricity, including a reasonable return on the investment and the costs of financing the project.

APPENDIX E

CORRESPONDENCE FROM BROILES & TIMMS, LLP

The following correspondence was submitted to SCAQMD's rule development staff regarding PR 1304.1 prior to the release of the NOP/IS and data provided in the correspondence was relied upon to analyze for potential adverse environmental impacts in this Draft EA. Comment letters received relative to the NOP/IS and responses to these comments can be found in Appendix C of this Draft EA.

BROILES & TIMMS, LLP

445 SOUTH FIGUEROA STREET, 27TH FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828

STEVEN A. BROILES
CHARLES F. TIMMS, JR.

February 19, 2013

VIA EMAIL (HPOURZAND@AQMD.GOV) AND U.S. MAIL

Henry Pourzand
Planning, Rule Development and Area Sources
SCAQMD
21865 Copley Drive
Diamond Bar, CA 91765

Re: Proposed Rule 1304.1; Second Comment Letter
Cities of Burbank, Glendale and Pasadena

Dear Mr. Pourzand:

The Cities of Burbank, Glendale and Pasadena ("the Cities") hereby submit this comment letter on Proposed Rule ("PR") 1304.1, which would impose fees amounting to millions of dollars on necessary utility boiler replacement projects. These proposed fees are without apparent justification. They could result in the delay, reduction in permitted capacity, or abandonment of these replacement projects and thereby result in potentially significant adverse impacts on emissions, electric system reliability, and the local economy. Because of these deep flaws in the proposed rule, the Cities urge the District to withdraw it.

The potential adverse air quality impacts of PR 1304.1 must be examined in detail under the California Environmental Quality Act ("CEQA").[1] In addition, the socioeconomic impacts

[1] The District's rulemaking program has been certified by the Resources Agency as equivalent to the environmental review procedures of CEQA. (Title 14, Code of California Regulations, Section 15251(l).) The program therefore is exempt from the requirement to prepare an Environmental Impact Report ("EIR") for proposed rules that may have significant environmental impacts. However, the program as certified by the Resources Agency, including specifically District Rule 110 and the District's CEQA Implementation Guidelines, requires that the staff report on a proposed rule must contain information equivalent to an EIR and must be made available for public review and comment for no less than 30 days prior to the adoption of the proposed rule. (Resources Agency, Statement of Findings, January 31, 1989 at 2, 5-6.)

of the proposed rule are required to be assessed as well. As part of the socioeconomic analysis, the District is required to consider and make available to the public its findings related to the cost-effectiveness of the proposed fees, which constitute a control measure under federal and state law. The Cities look forward to the opportunity to comment on these important documents when the District makes them available for public review.

The proposed rule appears to be a radical change in District policy regarding how utility boiler replacement projects should be regulated under its new source review ("NSR") program. The proposed fees were clearly not considered as a potential control measure in the 2012 Air Quality Management Plan ("AQMP"). The AQMP appears to assume that boiler replacement projects, like other projects that are exempt from offset requirements under Rule 1304, would be allocated any needed emissions offsets from the District's internal bank, without payment of any fees. These allocations are made pursuant to the District's NSR tracking system, now codified in Rule 1315, which enables the District to show that its NSR program is equivalent to the EPA's NSR program. Indeed, as recently as 2011, during the rulemaking to amend Rule 1315, the District rejected the alternative of requiring businesses seeking Rule 1304 exemptions to pay offset user fees on the basis that such fees would not accomplish the District's objective of "allow[ing] facility modernization which will increase efficiency and reduce air pollution" and "accommodating population growth" through implementation of Rule 1304. The District stated that "[o]ffset user fees would increase the cost of developing a new or modified source and would restrain the rate of growth in commercial and industrial sources that would otherwise qualify for the Rule 1304 exemption." (See Governing Board Resolution at p. C-2 and Attachment 1 to the Resolution, Discussion of Findings Relating to the Alternatives Evaluated in the Final PEA, pp. 16-17). The District has not explained what has happened since these two rulemakings that would justify taking the extraordinary step of singling out boiler replacement projects to pay offset user fees. Absent some explanation or related evidence and support, this radical change would appear to be an arbitrary and capricious action.

In addition to these air quality issues, the fees that the District seeks to impose via PR 1304.1 may constitute a prohibited tax under Proposition 26.

1. Background

PR 1304.1 would for the first time impose an annual "mitigation" fee on electrical generating facilities that use the offset exemption in Rule 1304(a)(2) for boiler replacements. The Rule 1304(a) (2) offset exemption was initially adopted about 20 years ago to complement a utility boiler retrofit requirement. The exemption removes any emissions-related disincentive for utilities to replace boilers with new, more efficient and lower-emitting equipment. In contrast, the proposed fee would create a clear disincentive for such replacements, particularly in cases where replacements are driven by economic and reliability objectives.

The proposed annual fee would be based in part on the market prices of Emission Reduction Credits ("ERCs") in 2008 through 2012, converted to an annual price, and based in part on the potential to emit ("PTE") of the boiler replacement, expressed as pounds per day of the relevant air contaminant. The PTE calculation is apparently intended to reflect the quantity of emissions offsets in the District's internal bank that must be debited, pursuant to Rule 1315, to enable the District to demonstrate equivalency with the federal NSR program. The annual fee effectively acts as a "lease" payment for the quantity of emissions offsets that must be debited from the account.

The Cities all operate small municipal boilers that are 50+ years old and now are either pursuing boiler replacement projects or have such projects under consideration. Each City's total boiler capacity is less than 110 MW. Each City's replacement project would be intended to satisfy the City's need for reserve capacity as well as to operate as a "peaking" facility to provide electric energy during periods of peak demand. In the case of Glendale, replacing the aging boilers would also increase the generation of renewable energy from landfill gas produced at the Scholl Canyon site inside the City of Glendale by as much as 50 percent over current levels, due to the superior efficiency of replacement units. Renewable energy produced within the state of California is the most valuable type of energy that can be used to comply with the Renewable Portfolio Standards ("RPS") set forth in SBX1-2, enacted in 2011; it was the clear intent of the state legislature to encourage such production in California by requiring increasing reliance on in-state renewable energy over time. Discouraging the replacement of Glendale's boilers would reduce the production of renewable energy in the state of California, and would thus interfere with the intent of California's RPS requirements.

While the District has held several working group meetings to explain the proposed rule and discuss issues raised by affected parties, in fact each meeting has raised more questions than it has answered.

2. <u>The District Has Not Clearly Stated the Purpose of the Proposed Fee</u>

An initial issue is that the District staff has not yet adequately explained the purpose of the proposed fee. Absent a clear statement of the purpose, it is difficult if not impossible to analyze potential alternatives that would more effectively accomplish the fee's purposes.

The Preliminary Draft Staff Report ("Staff Report") states that the purpose of the proposed fee is to require boiler replacement projects to pay annual fees for accessing the District's internal bank. (See Staff Report at page 1.) The Staff Report also suggests that the reason fees are needed is that boiler replacement projects will likely operate at a higher capacity factor than the boilers they replace, resulting in an increase in potential emissions over recent actual emissions from the boilers. (See Staff Report at pages 2-4.) Presumably, however, *any* project that seeks access to the District's internal bank, and not merely a boiler replacement project, will show an increase in future potential over recent actual emissions, because otherwise it would not need to access the internal bank. Thus, the statements in the Staff Report do not explain why fees are needed from boiler replacements as distinguished from any other facility that seeks to access the internal bank pursuant to a Rule 1304 exemption or the Rule 1309.1 priority reserve.

Moreover, the Staff Report also states that the fee proceeds will be "invested in air pollution improvement strategies" consistent with AQMD goals. (See Staff Report at p. 1.) During the working group meetings, District staff has confirmed that the fees will not be used to replenish the internal bank, because the projects on which the fee proceeds would be spent cannot meet the criteria for achieving creditable emissions reductions and thus deposits to the internal bank. Thus the proposed fee apparently bears <u>no</u> relationship to the internal bank and to the equivalency issue generally, because that already is addressed by rule 1315, which was amended in 2011 and has been approved by US EPA.

At another point, it was suggested that the purpose of the proposed fee is to reduce the size of boiler replacements. In that regard, the Cities are aware that District staff is concerned about an expected surge in boiler replacement projects from certain applicants who must comply with new requirements of the State Water Resources Control Board ("Water Board") to implement federal policy on cooling water intake structures. The apparent fear is that the District's internal bank may become depleted or overdrawn. To the extent that this fear explains the proposed fee, the District should understand that none of these Cities' boilers is required to meet the Water Board's cooling water intake structure requirements, but all of them would be subject to the proposed fee under PR 1304.1.

3. <u>The Proposed Fee May Result in Delay, Reduction in Permitted Capacity or Abandonment of Needed Boiler Replacement Projects</u>

The proposed fees under PR 1304.1 would raise the cost of the Cities' boiler replacements by tens of millions of dollars over the life of the projects. This substantial additional cost may result in the delay, reduction in permitted capacity or abandonment of these needed replacements.

The District staff appear to be under the impression that a typical boiler replacement project would not trigger a high mitigation fee because the Cities would only seek permits to operate at the expected average annual capacity factor, which the Cities anticipate will be modest. In fact, however, the boiler replacements planned by the Cities typically would seek permits to operate at a fairly high capacity factor, much higher than their expected average. Their existing boilers in many cases are already permitted for similar operation. While the Cities would expect to actually operate their boiler replacements relatively infrequently, possibly as little as 15% of the time, they need these units to be authorized to operate at much higher levels, in order to serve as reserve units in the event that other units are unexpectedly not available and to avoid reserve capacity payments to Balancing Area Authorities—Los Angeles Department of Water and Power ("LADWP") and California Independent System Operator ("CAISO").

The following two examples illustrate that the proposed fees on the Cities' boiler replacement projects may be quite high, and in fact high enough to discourage boiler replacement projects.

Example 1. City of Burbank Water and Power ("BWP") staff have done preliminary calculations for a hypothetical replacement of its 109 MW of old boilers with an LMS100, rated and permitted at 100 MW. The calculations are for operating under two different scenarios, one with no monthly limit on operating hours, and another with a limit of 270 hours per month. These calculations show that the proposed fees for the "no monthly limit" case, consistent with the permitted operation of the existing boilers, may reach $20 million, or more than 20% of the cost of the project, and may tip the scales in favor of continuing to run the existing boilers instead of replacing them. If the boiler replacement project is limited to no more than 270 hours/month of operation, then the proposed fee may increase the cost of the project by only 7%. While a mitigation fee of this magnitude might not be high enough to cause the utility to abandon the boiler replacement project, the reduction in monthly permitted capacity would have serious implications for system reliability, as will be discussed below. The calculations for these two scenarios are set forth in Attachment 1 to this letter.

When the calculations for the "no monthly limit" scenario were shared with District staff at one of the working group meetings, District staff claimed that they did not represent "reasonable" expectations because such high capacity factors are not really needed. However, limiting monthly operating hours reduces the unit's capacity to provide required reserves, because, for example, the plant might be shut down completely following a heat wave for the rest of the month. The lack of availability of the plant in these circumstances could cause reliability problems. District staff admittedly have not coordinated this proposal with technical experts at LADWP, the CAISO, North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") and so are unable to predict the impact of the proposed fee on the sizes or capacity factors of new generators that would replace the aging boilers.

Example 2. City of Glendale Water and Power ("GWP") staff have done similar calculations for a hypothetical replacement of its 108 MW of old boilers with a new combined cycle combustion turbine rated and permitted at 75 MW. The calculations show that the proposed fee would add about $6 million dollars to the up-front financing of the new plant, and would be expected to cost over $36 million over the life of the new plant, assuming that the new permit is based on a 100 percent capacity factor for reliability purposes. These additional costs could jeopardize the new construction. The calculations, which are based on Glendale's current understanding of the proposed fee, are set forth at Attachment 2 to this letter.

4. If Replacement Projects Are Not Built, Or If Their Permitted Capacity Is Reduced, There Will Be Potentially Significant Adverse Impacts on Emissions, Electric System Reliability, and the Local Economy

a. More Emissions From the Old Boilers

A relatively small increase in boiler operations could cause boiler emissions to exceed emissions from more efficient replacement equipment under consideration. Although they are expensive to operate, the boilers may need to operate more frequently in the future due to transmission constraints and local reliability needs.

The following two examples illustrate this point.

Example 1. BWP staff have done calculations comparing the operation of existing boilers with the operation of a boiler replacement unit to provide power during typical southern California summer peak demand, which was assumed to be 6 hours/day 4 days/week. In order for the boilers to provide power during these peaks, they would have to be put online at the beginning of the summer and operate 24 hours/day 7 days/week, operating at minimum load off peak and maximum load during the peak hours. During non-peak hours the operating boilers would provide needed spinning reserve, the reserve being difference in output between minimum operating load and the maximum load that could be achieved within 10 minutes. The replacement unit (assumed to be an LMS100), by contrast, can be started up and placed on line within minutes, only operating during the peak times and then switching off overnight. As an additional benefit, because of its quick-start capabilities, the LMS100 can provide these same non-spinning reserves while switched off, avoiding the need to consume expensive fuel and produce emissions off-peak when the energy it creates is not needed. This example shows that the pollutants emitted by the boilers operated to provide power for peak summer demand is *several times* the emissions of an LMS100. The calculations for this emissions comparison are set forth in Attachment 3 to this letter.

Example 2. GWP staff also have done calculations comparing the operation of existing boilers with the operation of the hypothetical replacement unit discussed above. GWP's boilers are currently constrained by a NO_x limit of 35 tons/year (70,000 pounds/year), pursuant to Rule 1135. In 2012, GWP's boilers' combustion of landfill gas (LFG) and natural gas (NG) actually emitted about 60,000 pounds of NO_x. Thus, GWP could burn additional natural gas in these boilers, for economic or reliability purposes, up to the 70,000 pound/year NO_x limit. As discussed above, GWP may seek to construct a new combined cycle combustion turbine rated and permitted at 75 MW and operating at an expected 60 percent annual capacity factor. With the new combustion turbine, GWP concludes that expected NO_x emissions would fall by about 48,000 pounds/year, VOC emissions would fall by about 19,000 pounds/year, CO emissions would fall by about 113,000 pounds/year, SO_2 emissions would fall by almost 4,000 pounds/year, and PM_{10} emissions would increase by about 15,000 pounds/year. Annual generation would increase in this example from about 150,000 MWh historically to over 650,000 MWh due to new uses for the new generation. In addition, the new generation would be more reliable, more flexible, and more efficient. But these emissions reductions will be jeopardized if the replacement project is not built because of the high mitigation fee. The calculations for this emissions comparison are set forth in Attachment 4 to this letter.

b. Less Reliable Electricity Supply System

The boilers are generally 50+ years old and are less reliable than replacement equipment would be. Local reliability demands in southern California are highlighted by the current extended outage at the San Onofre Nuclear Generating Station and the transmission outage that spanned from Arizona across southern California and into Baja California, Mexico, including the entire San Diego area, in September 2011.

Note that there also would be adverse impacts on system reliability if the proposed fee results in replacement projects with reduced permitted capacity because of the proposed fee. In that case, there will be a reduction in the total available capacity from the Cities' units, meaning less reserve capacity in the L.A. Basin.

The District must consult with the appropriate energy regulatory agencies and Balancing Area Authorities—the CEC, LADWP, the CAISO, NERC and WECC—regarding potential local reliability impacts of the proposed fee, whether those impacts result from the continued operation of the existing boilers or from the reduction in total capacity if replacement projects have reduced permitted capacity due to the proposed fee.

Furthermore, the CEC has just issued the "2012 Integrated Energy Policy Report Update", January 2013, CEC-100-2012-001-LCF ("CEC Report"), which raises significant issues regarding the adequacy of electricity supply in the LA Basin generally, and urges inter-agency coordination to ensure a reliable and economic supply of energy. A combination of pressures is likely to drive toward retirement of old boilers and replacement with new flexible gas-fired combustion turbines, if economic: the continued SONGs outage, the retirement/repowering of once-through cooling facilities, the shift toward electric vehicles, an increasing demand for coastal air-conditioning due to climate change, and the integration of intermittent renewable resources. (See Chapter 4 of the Update, generally.) Financing these investments will be a challenge under the best of conditions. The District should not erect additional economic impediments to replacing old boilers.

c. Higher Local Costs and Fewer Local Jobs

If there are fewer boiler replacement projects, local utilities will have to pay out-of-state suppliers to integrate the output of variable and intermittent renewable resources, such as wind and solar. Existing, older boilers were not designed for this type of service, and either cannot physically provide the service or could do so only at considerable cost. The foregone replacement projects also will mean a loss of jobs and economic development in southern California. The District must discuss this potential loss of economic activity in the socioeconomic impact analysis.

d. Adverse Impacts on Retail Customers in the LA Basin

If the overall generation capacity in the Los Angeles basin that serves electricity demands is considerably reduced, the shortfall will have to be met with electricity generators located outside of the Los Angeles area. This would increase the likelihood of electricity outages and result in higher electricity costs due to transmission costs and losses. This also would result in higher greenhouse gas emissions because, in addition to transmission losses, less efficient and higher-emitting power plants (likely a mix of natural gas and coal-fired power plants) would provide needed electricity.

Again, these are topics that should be taken up in the socioeconomic impact analysis. The District must consult with the appropriate energy regulatory agencies--LADWP, the CAISO, NERC and WECC—and also take into account the conclusion in the CEC Report cited above.

These potential impacts also underscore that the proposed fee is a simplistic solution to a complex problem that requires substantial consultation with other agencies, whose expertise would complement that of the District in analyzing the effects of the proposed rule.

5. These Potential Impacts Compel the District to Prepare the Equivalent of an Environmental Impact Report ("EIR") and a Socio-Economic Analysis Prior to Adopting PR 1304.1.

a. PR 1304.1 Is a Project Subject to CEQA

PR 1304.1 is a "project" subject to CEQA. A "project" is defined by statute in part as "an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect change in the environment." Cal. Pub. Res. Code § 21065. The CEQA Guidelines further define a "project" as "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or reasonably foreseeable indirect physical change in the environment." 14 CCR § 15378.

As explained above, the mitigation fees imposed by PR 1304.1 may result in the delay or abandonment of the Cities' boiler replacement projects. As a result, the Cities' existing boilers would operate more of the time and for more years, resulting in potentially significant adverse impacts on emissions, electric system reliability, and the local economy. Accordingly, PR 1304.1 is a project subject to CEQA.

Under cases interpreting CEQA, if an activity may have reasonably foreseeable environmental effects, it will qualify as a "project" despite claims that these effects are speculative or remote because they occur in the future or result from actions of third parties in response to the activity instead of from the activity itself. See, for example, *Plastic Pipe Fittings Assn. v. California Building Standards Commission* (2004) 124 Cal. App.4th 1390, 1399, 1412-13 (proposed building standard allowing the use of a specific type of plastic was a CEQA "project" because evidence in the record indicated that chemicals leaching from the plastic could contaminate potable water and cause the pipes to be subject to mechanical failure; court rejected contention that the causal link between the regulation allowing its use and the alleged impacts was too remote and held that the alleged impacts were a "reasonably foreseeable indirect impact."); and *Fullerton Joint High School District v. State Board of Education* (1982) 32 Cal. 779, 794-797 (the Supreme Court held that a proposed reconfiguration of school districts was a "project" because the action would likely cause the construction of a new high school, might cause the abandonment of other facilities, and would affect bus routes and traffic patterns).

Two additional cases involving air districts support the conclusion that CEQA review is required here. They are exemption cases, but their conclusions are relevant to the question of whether the activities involved here would qualify as CEQA "projects." See *Dunn-Edwards Corp. v. Bay Area AQMD* (1992) 9 Cal.App.4th 644 (court held that a regulation limiting the solvent in architectural coatings was not categorically exempt from CEQA because there was evidence in the record that the regulation may have adverse emissions impacts due to the fact that the regulation would require lower quality products, resulting in the use of more product—more frequent application and more coats); and *California Unions for Reliable Energy (CURE) v. Mojave Desert Air Quality Management District* 178 Cal.App.4th 1225, 1240-46 (court held that a regulation allowing the use of road paving to offset increases in airborne dust was not categorically exempt from CEQA because there was evidence in the record that road paving would tend to have adverse emissions impacts in that it would involve trading road dust for combustion emissions, which would stay in the air longer, spread more widely, and be more likely to cause disease; court stated that the focus should not be on the regulation alone, but rather on its reasonably foreseeable direct and indirect physical effects and noted that while the adoption of the regulation did not cause any road paving by itself, it certainly encouraged third parties to pave roads).

It is clear from these cases that courts are not at all reluctant to consider potential environmental effects resulting from foreseeable conduct by third parties in response to the adoption of a rule in determining whether adoption of the rule may be a CEQA "project." They reject claims that such effects are too remote or speculative to warrant CEQA review. The reasonably foreseeable effects involved in these cases are just the types of effects the Cities have suggested may result from adoption of PR 1304.1.

b. <u>PR 1304.1 Is Not Exempt from CEQA by Statute or Regulation</u>

PR 1304.1 is not exempt from CEQA by statute or regulation. The most likely exemption claim for PR 1304.1 would be that it is covered by a Class 8 categorical exemption as an action taken by a regulatory agency for protection of the environment. 14 CCR § 15308. This was the exemption claimed by the air districts in the *Dunn-Edwards* and *CURE* cases cited above. But in both cases the reviewing court held this exemption did not apply because the record showed that there may be adverse impacts. The same result should be reached here.

c. An EIR Is Required Because There is a "Fair Argument" that PR 1304.1 May Have a Significant Effect on the Environment

An agency is required to prepare an EIR if a project it proposes to carry out or approve may have a "significant" effect on the environment. Cal. Pub. Res. Code § 21100. The CEQA Guidelines elaborate on this requirement. See 14 CCR § 15064. If there is substantial evidence, in light of the whole record before the agency, that a project may have a significant effect on the environment, the agency shall prepare a draft EIR. 14 CCR § 15064(a). In evaluating the significance of the environmental effect of a project, the agency shall consider both direct physical changes, and reasonably foreseeable indirect physical changes, in the environment which may be caused by the project. 14 CCR § 15064(d). If the agency is presented with a "fair argument" that a project may have a significant effect on the environment, the agency shall prepare an EIR even if it may also be presented with other substantial evidence that the project will not have a significant effect. 14 CCR § 15064(f)(1).

In this case, as the Cities have alleged and have demonstrated with evidence (see above discussion and attachments), there is a fair argument that the proposed fees may have a significant effect on the environment. The significant effects include potential increased emissions resulting from the increased operation of the Cities' existing boilers and the potential effects of a less reliable electricity supply system. Therefore, the District must prepare an EIR.

Interestingly, courts have held that adoption of a mitigation fee program requires preparation of an EIR. See, for example, *Center for Sierra Nevada Conservation v. County of El Dorado* (2012) 202 Cal.App.4th 1156 (court held that county was required to prepare an EIR before its adoption of an oak woodland management plan, which included a mitigation fee option, where the earlier program EIR for the county's general plan anticipated the mitigation fee option but did not set the fee rate, how the acreage subject to the fee rate should be measured, or how the off-site oak woodland losses would be mitigated by the fees). The *Center for Sierra Nevada Conservation* court based its decision in part on *California Native Plant Society v. County of El Dorado* (2009) 170 Cal.App.4th 1026 (court held that county was required to prepare an EIR for a development project despite developer's payment of a rare plant impact fee through the county's ecological preserve fee because the fee program did not receive CEQA review when it was adopted).

In a case involving a challenge to the District's failure to prepare an EIR for a permit to allow a refinery modification, the Supreme Court held that the physical conditions actually existing at the time of analysis should be used as the baseline, rather than the maximum permitted capacity, in determining whether the modification would have a significant effect on the environment. *Communities for a Better Environment v. South Coast AQMD* (2010) 48 Cal.4th 310, 316, 326-27. This means that in describing the emissions impacts of increased use of the boilers resulting from delay or abandonment of boiler replacements, any increase above actual levels is relevant.

d. <u>The District Has Acknowledged the Need to Prepare a Socioeconomic Analysis of PR 1304.1; That Analysis Must Address the Cost-Effectiveness of the Proposed Fees</u>

In its preliminary staff report, the District staff claims that a socioeconomic analysis is not legally required for PR 1304.1 because it "merely charges a fee and does not significantly affect air quality or emissions limitations." On the contrary, the proposed fees may adversely affect air quality, and therefore an assessment of the socioeconomic impact of the proposed rule is required by law.

As the Cities have alleged, and as they have demonstrated with evidence (see above discussion and attachments), the proposed mitigation fee may result in the abandonment of boiler replacement projects and the continued operation of their existing boilers. The continued operation of the existing boilers is likely to cause adverse impacts on emissions, electric system reliability, and the local economy. The District therefore is required to prepare an assessment of the socioeconomic impacts of the proposed rule, including a report on the availability and cost-effectiveness of alternatives. Cal. Health & Saf. Code § 40440.8.

The socioeconomic assessment under Section 40440.8 must identify (i) the types of industries affected by the proposed rule, (ii) the impacts of the proposed rule on employment and the economy in the South Coast Basin, (iii) the probable costs of the proposed rule, (iv) the cost-effectiveness of alternatives to the proposed rule, (v) the potential of the proposed rule to reduce emissions, and (vi) the necessity of adopting the proposed rule in order to attain ambient air standards.

We assume that the District will use input-output models as it has in the past to identify affected industries and impacts on overall employment and the economy in the South Coast Basin. In these comments, the Cities provide information to the District on the probable costs of the proposed rule, based on information and analyses available at this time. If future opportunities arise to modify or add to this information, or if the Cities' understanding of the proposed rule changes, the Cities reserve the right to provide additional comments and information to the District.

<u>Probable costs.</u> As noted above, the proposed fee will add millions of dollars per year to the combined revenue requirements of the Cities, costs which will be passed along to retail ratepayers.

<u>Cost-effectiveness.</u> Given that the proposed fee will most likely increase air emissions, both by causing the delay or abandonment of replacements and by altering the incentive to operate new units if they are installed, the fee would appear to fail a cost-effectiveness test. The District's cost-effectiveness rankings address the relative costs of *reducing* emissions, not the costs of *increasing* emissions.

Potential emissions reductions. As noted above, the Cities have concluded that a delay in, or abandonment of, boiler replacements would cause air emissions to be higher than they would be without the delay or abandonment. The proposed fee is thus detrimental to the environment, unless the District can demonstrate that additional, cost-effective control measures can be undertaken that will offset the emissions from continued and increased operation of the old boilers.

Necessity of adoption. In view of the fact that the 2012 AQMP projected attainment without the payment of the proposed fees for boiler replacement projects, then it would appear that the proposed fees are not necessary in order to attain the standards.

For another reason, the socioeconomic assessment also must include a detailed assessment of the cost-effectiveness of the proposed fees. District staff have acknowledged that one purpose of the proposed rule is to reduce the size of boiler replacement projects, which also would reduce emissions from these projects. Accordingly, the proposed fees constitute a control measure under state and federal law. Under state law, the required socioeconomic impact assessment must include the District's findings related to the cost-effectiveness of the proposed rule, as well as the basis for the findings and the considerations involved. Cal. Health & Saf. Code §§ 40703, 40922.

The cost-effectiveness findings will necessarily be complex. First, these findings must address the emissions reductions claimed to be achievable from the disposition of the proposed fees. In addition, these findings must address emissions changes that may occur if the fees result in the delay or abandonment of the boiler replacement projects. Relevant emissions changes would include emissions reductions if the boiler replacement projects are indeed reduced in size, as well as emissions increases from other generating facilities, such as the existing boilers, that would need to operate if the boiler replacement projects are reduced in size.

6. If PR 1304.1 Is Adopted, It Should be Modified in the Following Respects to Make the Mitigation Fee More Appropriate and Fair

a. Any Fee Should Not Be Based on ERC Prices

There is no compelling reason to base the formula for the proposed fee on the simple average of historical market prices of ERCs, plus a built-in inflation adjustment. According to the District's calculations, the recent market price of one pound per day of PM_{10} ERCs is on the order of $185,000, which reflects a highly illiquid market, and apparently excludes transactions that were priced at zero due to being labeled as "barter" or "subsidiary" transactions. Using the simple average of reported non-zero prices is not an accurate indicator of historical market conditions, and thus is an unreasonable basis for fees that the Cities would pay for boiler replacement projects in future. As the District staff have conceded, the proposed mitigation fee bears no relation to either the external ERC market or the District's internal bank. Boiler replacements are exempt from offset requirements, and thus ERCs are not required. Instead, per District Rule 1315, the District's internal bank is used to show equivalency with the federal NSR program. The proposed mitigation fee would not be used to replenish the internal bank, because reductions achieved with fee proceeds cannot meet the criteria for emissions credits. Thus, a proposed fee can be based on anything that is reasonable. There are many options available.

b. Any Fee Should Be Based on Actual Emissions Instead of PTE

The proposed fee formula requires that the mitigation fee must be based on the maximum permitted operation of the boiler replacement project. This fee formula is not reasonable. The Cities' anticipated projects would be authorized to operate at a fairly high capacity factor, for multiple reasons. In fact, however, these projects, which are peaking facilities, most likely would operate at relatively low capacity factors. Thus the Cities would be required pay to reserve emissions rights that would never or seldom be used.

The fee proposal should be modified, if adopted at all, to require that a fee is required for the total MWh that the boiler replacement project actually operates, instead of the maximum permitted MWh. Thus, the more MWh the project actually operates, the higher the annual payments to AQMD. This type of formula would avoid an inherent defect in the currently proposed formula, which discourages boiler replacement operations from considering environmental impacts, because the annual fee would be based on maximum permitted operation and therefore would be a sunk cost. Once the proposed fee is paid, the Cities would not have to take into account environmental costs in their scheduling and dispatch decisions, which is simply the wrong result from an air quality perspective. The marginal cost of a MWh from a boiler replacement project would not incorporate the cost of emissions, and so all else equal, the boiler replacement would operate more than it would if fees were paid on a per MWh basis. This reinforces the conclusion that the District needs to consider the environmental impacts of the proposed rule.

c. Covered Facilities Should Be Credited with Emissions Based on Boiler Operations

Under PR 1304.1, a boiler replacement project would pay a fee for "leasing" emissions credits from the District's internal bank. The fee payments would be potentially reduced based on the historical operation of the replaced boilers. But once the proposed fee is in place, the emissions credits corresponding to the historical boiler operation would be lost to the project owner forever. These credits could have significant value in the future, and PR 1304.1 should include a mechanism for that value to be preserved for the benefit of the owner.

d. Proposed Fee Should Allow for Contingent Payments In Lieu of Required 5-Year Upfront Payments

PR 1304.1 would require upfront payment of the mitigation fee for the first five years of operation of the boiler replacement project. The fee would be payable prior to the issuance of the permit to construct. This is a substantial upfront fee, which is at risk depending on whether the project is successfully completed. The District should allow project applicants to mitigate this risk by entering into a "contingent contract" with the District, under which either the fee would be paid if the new project is completed, or a lower, contingency fee would be forfeited if the project is not completed.

e. Proposed Fee Should Be Applied More Broadly to Other Categories of Facilities that Are Exempt from Offsets

Any fee that is adopted should apply to all categories of facilities that have offset exemptions, with exceptions where appropriate. All categories of facilities that have offset exemptions require the District to set aside emissions credits from its internal bank, and all of them should be subject to any fee imposed to prevent the District's internal bank from being too rapidly depleted. There does not appear to be any justification for limiting such a fee to boiler replacement projects alone.

To cite a simple example, there is no good reason why a boiler replacement project should pay a fee, while a functionally identical replacement project, which is exempt from offsets pursuant to Rule 1304(a)(1), should not. Both types of replacement projects could result in lower or higher emissions, depending on how they operate. The main difference is that the functionally identical replacement exemption is capped by the PTE of the equipment being replaced, while the boiler replacement exemption is capped by the megawatt capacity of the equipment being replaced.

Applying the proposed fee to all categories still allows for the District to grant exceptions where appropriate, whether based on the size of the facility or other considerations.

f. Proposed Fee Should Be Adjusted When Attainment Is Achieved

When the District attains the PM_{10} standard, the market price for PM_{10} ERCs may fall dramatically. The proposed fee for boiler replacements, however, would continue to escalate at an inflation index rate. The proposed fee should be adjusted to reflect changes in ERC market conditions as they change over time.

g. Proposed Fee Should Be Adjusted if Permittee Provides Partial Amounts of ERCs or Seeks Change in Operating Hours During the Term of the Permit

The Proposed Rule should provide for adjustment of the fee amount if the permit applicant or permittee provides ERCs for pollutant(s) listed in PR 1304.1, Table A, or seeks a change in operating hours during the term of the permit that reduces the PTE for pollutants listed in Table A.

7. Proposed Fee May Constitute a Prohibited Tax

Proposition 26, enacted in 2010, is intended in part to stop state and local governments from funding their operations with fees rather than new or increased taxes, thereby avoiding the requirement that approval be obtained from two thirds of the voting public. The proposition includes a new definition of "tax" to include all charges imposed by local government, including regional governmental entities, with certain limited exceptions. Cal. Const., Art. XIIIC, § 1(e).

The most likely exception that may apply to the proposed fees under PR 1304.1 is for a specific benefit conferred or privilege granted by the District to the payer. § 1(e)(1). The benefit or privilege would be allowing the boiler replacement projects to avoid having to obtain ERCs and instead obtain emission offset allocations from the District's internal bank.

This exception, however, is limited to charges that do not exceed the reasonable costs to the local government entity of conferring the benefit or granting the privilege. *Id.* This raises several problems for the proposed fee. First, the District has not yet indicated the magnitude of fees it expects to collect annually from boiler replacement projects under the fee formula in PR 1304.1. Given the magnitude of fees that the Cities estimate may apply to their relatively small projects, the District-wide fees collected from all boiler replacement projects may amount to tens of millions of dollars annually. If so, then it is necessary and reasonable to ask whether tens of millions of dollars annually exceed the reasonable costs to the District of granting access to the internal offset bank.

Second, District staff have indicated that the purpose of the fees is not to replenish the internal bank, because the actions or activities to be undertaken by the District would not yield emissions reductions that would qualify for the internal bank. Instead, the fee proceeds would be used to obtain other kinds of emissions reductions, which cannot meet the rigorous criteria for offsets (either ERCs or credits in the internal bank). There is thus no logical connection between the proposed fees and the internal bank: emission credits in the bank will not be affected by the proposed fee unless the District is successful in discouraging access to the bank, in which case no revenues will be collected from the proposed fee. Absent some explanation of how the proposed fees are logically connected to access to the internal bank and furthermore do not exceed the reasonable costs to the District of allowing access to the internal bank, the fee proposal appears to constitute an unconstitutional "tax" on the ratepayers of the Cities. This tax would be paid by the Cities' ratepayers because there is no other source of funds to pay for such fees.

As these comments amply illustrate, absent further explanation and justification from District staff, it would appear that the Governing Board will not be able to make the findings of necessity, authority, clarity, consistency, nonduplication, and reference, that are required by statute before the Board adopts this proposed rule. Cal. Health & Saf. Code § 40727.

Please let us know if you have any questions. We appreciate the opportunity to provide these comments and look forward to continuing to participate in the working group and to help the District Governing Board make an informed decision on PR 1304.1.

Sincerely,

Charles F. Timms, Jr.

cc: Steve Smith (ssmith@aqmd.gov)
Planning, Rule Development & Area Sources, CEQA Section
Gurcharan Bawa (gbawa@cityofpasadena.net)
Lon Peters (lpeters@ci.glendale.ca.us)
Kim Yapp (kyapp@burbankca.gov)

ATTACHMENT 1

Attachment 1

Example 1. BWP calculations for replacing Olive 1 & 2 boilers with and LMS 100 permitted for 1300 hours/year annual operations (<15% capacity factor)
Annual offset fee caculated per proposed AQMD Rule 1304.1
The table below compares the proposed Offset fees for an LMS100 replacement unit with a PTE based on a peak month of 270 or 720 operating hours.

	$F_{i\ for\ 270\ hour/month}$	$F_{i\ for\ 720\ hour/month}$	R_f	$PTE_{rep\ for\ 270}$ $hr/month$	$PTE_{rep\ for\ 720}$ $hour/month$	OF_i	C_{rep}**	$C_{2yavgexisting}$***	C_{rep}- $C_{2yavgexisting}$/ C_{rep}
PM10	$344,353	$918,275	$7,245	50	133	1.0	130,000	6165	95.26%
SOx	$10,016	$26,710	$2,434	4	12	1.0	130,000	6165	95.26%
VOC	$9,655	$25,747	$436	19	52	1.2	130,000	6165	95.26%
Total Annual Offset fees	$364,024	$970,732							
Initial 5-year payment	$1,820,122	$4,853,660							
Net present value of fees for 30 year project with a 3% CPI increase	$7,288,038	$19,434,767							

ATTACHMENT 2

Attachment 2

Proposed Rule 1304.1 - Cost to Glendale Water & Power of Boiler Replacement Fee

Inputs

		PM	Nox	Sox	VOC	Sources
R(i)	Annual fee for pollutant (i), in dollars per pound per day	$ 7,245	$ 2,653	$ 2,434	$ 436	AQMD
PTE(rep)	Permitted PTE of new unit, in pounds per day	235.62	101.37	235.62	6.85	Report on LM6000 (adjusted to 100% capacity factor for permit)
OF(i)	Offset factor, scalar	1.00	1.20	1.00	1.20	AQMD formula for proposed fee
	MWh ratio	0.77	0.77	0.77	0.77	Calculated below
C(rep)	Maximum MWh of permitted new generation per year	657,000				75 MW at 100% capacity factor
C(boiler)	Average annual MWh generated by boilers in last two years	152,537				Grayson historical data

PTE(rep) LM6000PF (DLE with chiller, combined cycle)	PM	Nox	Sox	VOC	Units
	43.00	18.50	43.00	1.25	tons/year
	0.12	0.05	0.12	0.00	tons/day
	235.62	101.37	235.62	6.85	pounds/day

Formula for Annual Fee

F(i) = R(i) * PTE(rep) * OF(i) *((C(rep) - C(boiler))/C(rep))

Calculation of Annual Fee

PM	$ 1,310,714
Nox	$ 247,794
Sox	$ 440,342
VOC	$ 2,752
	$ 2,001,602 per year

Calculation of Total Life-of-Project Fees

Upfront	$ 10,008,009
NPV	$ 51,287,074
Total	$ 61,295,083

ATTACHMENT 3

Attachment 3

Example 1. BWP calculation of the difference in pollutant emissions between operating Olive 1 & 2 and an LMS 100 to provide power during peak times for a typical summer Peaks assumed to last 6 hours/day 4 days/week. Page 2 summarizes the difference in pollutant emissions in pounds and tons.

Parameter	Olive 1	Olive 2	Olive 1 + 2	Olive Notes	LMS100 (Lake 2)	LMS100 Notes
Owner/Operator	BWP/BWP	BWP/BWP			BWP/BWP	
Year Placed in Service	1958	1963			Future	
Unit Type	Steam	Steam			Simple Cycle Intercooled	
Manufacturer	Riley Stoker	Riley Stoker			General Electric	
Fuel	Natural Gas	Natural Gas			Natural Gas	
Running Hours	2,208	2,208		92 days (Jul, Aug, Sep)	312	peaking only
Maximum Load, MW	50	50		assumed	100	assumed
Heat Rate, BTU/kw-hr	13,500	13,500		assumed as typical	8,400	base load spec
mmBTU/hr	675	675			840	
Weeks	13	13			13	
Days/week	4	4			4	
Hours/day	6	6			6	
MAX Load Hours	312	312			312	
Minimum Load, MW	20	20		assumed as typical	0	
Heat Rate, BTU/kw-hr	13,500	13,500		assumed as typical	8,400	base load spec
mmBTU/hr	270	270			0	
MIN Load Hours	1,896	1,896		balance	0	
TOTAL MW-hrs	53,520	53,520	107,040		31,200	
TOTAL mmBTU	722,520	722,520	1,445,040		262,080	
HHV, BTU/cf	1,050	1,050	1,050	SCAQMD default	1,050	SCAQMD default
TOTAL mmcf	688	688	1,376		250	
ROG, lb/mmcf	5.5	5.5		AP-42 Table 1.4-2	2.69	BACT is 2 ppmv @ 15% O_2
SO_x, lb/mmcf	0.6	0.6		AP-42 Table 1.4-2	0.6	AP-42 Table 1.4-2
PM_{10}, lb/mmcf	7.6	7.6		AP-42 Table 1.4-2	6.93	AP-42 Table 3.1-2a
CO, lb/mmcf	84.0	84.0		AP-42 Table 1.4-1	9.42	BACT is 4 ppmv @ 15% O_2
NO_x, lb/mmcf	6.37	6.37		BACT is 5 ppmv @ 3% O_2	9.67	BACT is 2.5 ppmv @ 15% O_2
CO_2 e, lb/mmcf	120,247	120,247		AP-42 Table 1.4-2	121,166	AP-42 Table 3.1-2a

Attachment 3

Parameter	Olive 1	Olive 2	Olive 1 + 2	Olive Notes	LMS100 (Lake 2)	LMS100 Notes
ROG, lbs	3,785	3,785	**7,569**		**672**	
SO_X, lbs	413	413	**826**		**150**	
PM_{10}, lbs	5,230	5,230	**10,459**		**1,730**	
CO, lbs	57,802	57,802	**115,603**		**2,351**	
NO_X, lbs	4,386	4,386	**8,772**		**2,413**	
CO_2 e, lbs	82,743,472	82,743,472	**165,486,944**		**30,243,066**	
ROG, tons	1.89	1.89	**3.78**		**0.34**	
SO_X, tons	0.21	0.21	**0.41**		**0.07**	
PM_{10}, tons	2.61	2.61	**5.23**		**0.86**	
CO, tons	28.90	28.90	**57.80**		**1.18**	
NO_X, tons	2.19	2.19	**4.39**		**1.21**	
CO_2 e, tons	41,372	41,372	**82,743**		**15,122**	
GHG Rate, lbs/MW-hr	1,546	1,546	**1,546**	standard is 1,100 lbs/MW-hr	**969**	standard is 1,100 lbs/MW-hr
CO_2 e, metric tonnes	37,532	37,532	**75,064**		**13,718**	

ATTACHMENT 4

Attachment 4

Proposed Rule 1304.1 - Emissions Increases Due to Proposed Fee

Hypothetical Annual Boiler Emissions (lbs) if NOX Limits Output

	NOX	CO	SO2	VOC	PM
LFG	33,316	24,213	4,945	13,641	27,283
NG	36,684	105,054	750	6,879	9,505
Total	70,000	129,267	5,695	20,520	36,788

Pro Forma Annual Emissions for LM6000 @ 60% Capacity Factor (lbs/year)

NOX	CO	SO2	VOC	PM
22,200	15,900	1,892	1,500	51,600

Emissions Changes due to Replacement of Old Boilers (pounds/year)

NOX	CO	SO2	VOC	PM
-47,800	-113,367	-3,803	-19,020	14,812

BROILES & TIMMS, LLP

445 SOUTH FIGUEROA STREET, 27TH FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828

STEVEN A. BROILES
CHARLES F. TIMMS, JR.

February 22, 2013

VIA EMAIL (HPOURZAND@AQMD.GOV) AND U.S. MAIL

Henry Pourzand
Planning, Rule Development and Area Sources
SCAQMD
21865 Copley Drive
Diamond Bar, CA 91765

Re: Proposed Rule 1304.1; Correction to Second Comment Letter Cities of Burbank, Glendale and Pasadena

Dear Mr. Pourzand:

The purpose of this letter is to correct some erroneous emissions calculations made in support of the second comment letter from the Cities of Burbank, Glendale and Pasadena, which was submitted to the District earlier this week. The emissions calculations were used to estimate mitigation fees due for a hypothetical boiler replacement project for the City of Glendale. The calculations also were used to estimate the change in annual emissions by operating the replacement project in lieu of the existing boilers.

The corrected emissions calculations result in the following changes in the comment letter:

1. The proposed fee for the replacement project would be lower than originally estimated: about $4.7 million would be added to the upfront financing of the replacement project and $24.1 million over the life of the new plant, instead of $6 million and $36 million, respectively, as indicated in the letter. (See page 5, Example 2.)

2. Emissions of PM_{10} from operating the replacement project in lieu of the existing boilers would *decrease*, instead of *increase*, as originally estimated. Specifically,

> emissions of PM_{10} would *decrease* by 14,611 lbs/year, instead of *increase* by 14,812 lbs/year. In addition, emissions of other air contaminants also would decrease, although by less than originally estimated. Specifically, emissions of NO_x would decrease by 39,056 lbs/year, instead of by 47,800 lbs/year; emissions of CO would decrease by 99,131 lbs/year, instead of by 113,367 lbs/year; emissions of SO_2 would decrease by 3,775 lbs/year, instead of by 3,803 lbs/year; and emissions of VOC would decrease by 11,910 lbs/year, instead of by 19,020 lbs/year. (See page 6, Example 2.)

Attached to this letter are corrected Attachments 2 and 4 to the original letter. Please keep this letter and the corrected attachments along with the original comment letter.

Please let us know if you have any questions or need any additional information. Thank you.

Sincerely,

Charles F. Timms, Jr.

cc: Steve Smith (ssmith@aqmd.gov)
Planning, Rule Development & Area Sources, CEQA Section
Gurcharan Bawa (gbawa@cityofpasadena.net
Lon Peters (lpeters@ci.glendale.ca.us)
Kim Yapp (kyapp@burbankca.gov)

Attachment 2

Proposed Rule 1304.1 - Cost to Glendale Water & Power of Boiler Replacement Fee

Inputs

		PM10	NOX	SO2	VOC	Sources
R(i)	Annual fee for pollutant (i), in dollars per pound per day	$ 7,245	$ 2,653	$ 2,434	$ 436	AQMD proposed rule
PTE(rep)	Permitted PTE of new unit, in pounds per day	101.27	141.30	8.77	39.32	Black & Veatch, EPA, AQMD
OF(i)	Offset factor, scalar	1.00	1.20	1.00	1.20	AQMD formula for proposed fee
	MWh ratio	0.77	0.77	0.77	0.77	(C(rep) - C(boiler))/C(rep)
C(rep)	Maximum MWh of permitted new generation per year	657,000				75 MW at 100% capacity factor
C(boiler)	Average annual MWh generated by boilers in last two years	152,537				Grayson boilers' historical data

		PM10	NOX	SO2	VOC	Units
PTE(rep)	LM6000PF (DLE with chiller, combined cycle) @ 100% capacity factor	18.48	25.79	1.60	7.18	tons/year

Formula for Annual Fee

F(i) = R(i) * PTE(rep) * OF(i) *((C(rep) - C(boiler))/C(rep))

Calculation of Annual Fee

PM	$	563,329
Nox	$	345,390
Sox	$	16,386
VOC	$	15,795
	$	940,899 per year

Calculation of Total Life-of-Project Fees

Upfront	$ 4,704,497
NPV	$ 24,108,678
Total	$ 28,813,175

Attachment 4

Proposed Rule 1304.1 - Emissions Increases Due to Proposed Fee

Hypothetical Annual Boiler Emissions (lbs) if NOX Limits Output

	NOX	CO	SO2	VOC	PM
LFG	33,316	24,213	4,945	13,641	27,283
NG	36,684	105,054	750	6,879	9,505
Total	70,000	129,267	5,695	20,520	36,788

Pro Forma Annual Emissions for LM6000 @ 60% Capacity Factor (lbs/year)

NOX	CO	SO2	VOC	PM
30,944	30,136	1,920	8,610	22,177

Emissions Changes due to Replacement of Old Boilers (lbs/year)

NOX	CO	SO2	VOC	PM
-39,056	-99,131	-3,775	-11,910	-14,611

From: CFTimms@aol.com
Sent: Thursday, March 21, 2013 3:26 PM
To: Henry Pourzand; Mohsen Nazemi; Laki Tisopulos; Robert Pease
Cc: BAWA, GURCHARAN; Lori Peters; kyapp@burbankca.gov; kuwright@nrg-llc.com
Subject: PR 1304.1; Response to District Staff Request for Additional Information
Attachments: BWPcalculations.XLSX; GWPcalculations.xlsx

Following the last working group meeting on February 27, District staff asked for additional information from the Cities of Burbank, Glendale and Pasadena ("the Cities") regarding several matters the Cities raised in their earlier comment letters on Proposed Rule ("PR") 1304.1 and at the workshop. The purpose of this letter is to provide that additional information.

-

1. <u>Emissions and mitigation fee calculations</u>

-

District staff asked for clarification on the Cities' mitigation and fee calculations for boiler replacements. Attached to this letter are two Excel files containing Burbank's and Glendale's emissions and fee calculations. The files include the NO_x, CO and VOC emission calculations, based on current Best Available Control Technology limits, and provide links to the US EPA documents containing emissions factors used in the SO_x and PM_{10} calculations. The files also include tables showing the corresponding mitigation fee calculations based on these emissions and related worksheets.

Burbank's calculations are for a LMS100 to replace approximately 100 MW of boiler capacity (a reference to 109 MW in our second comment letter was incorrect). Glendale's calculations have been updated for an LM6000 "two-on-one" facility configuration with a generation capacity of 100 MW, which would be intended to replace the existing boiler capacity completely, for local reliability purposes (further discussed below). Glendale's previous calculations were for an LM6000 "one-on-one" facility configuration with a generating capacity of 75 MW, which would be a reduction from current boiler capacity.

-

2. <u>Local Generation and Reliability</u>

-

District staff also asked the Cities to elaborate on their claim that, under the current version of PR 1304.1, their boiler replacements would incur high mitigation fees even though they are expected to operate for limited periods of time. The high mitigation fees would be required because the replacement units would have to be permitted at or near maximum daily emissions (calculated as the daily average of maximum monthly emissions) in order to provide needed reserves. The replacement units, however, would most likely operate only a limited period of time to serve peak load and integrate renewable power generation. By requiring the Cities to pay high mitigation fees for limited expected operation of the replacement units, PR 1304.1 is punitive, unfair, and bad policy.

All of the Cities have limits on their ability to import energy from outside their boundaries because each City has only one interconnection for imports; Burbank and Glendale interconnect with LADWP, and Pasadena interconnects with SCE. (Glendale also interconnects with Burbank, but this does not increase total import capability for the two Cities combined.) Thus, all three Cities use a combination of imported and local generation to supply retail loads inside each City and to meet reliability requirements imposed by the WECC, NERC and either the CAISO or LADWP as Balancing Area Authority.

On many days each year, the Cities' loads exceed their import capabilities. Thus, the Cities need local excess capacity to meet peak loads and required reserves. Without that local excess capacity (primarily boilers) providing needed reserves, the Cities' historical actual peak loads would have triggered brown-outs or even black-outs within the Cities if any system transmission or generation failures had required the on-site boilers to increase output to compensate and the boilers had failed under the increased load. This potential reliability issue will only be exacerbated as the boilers age and are subject to more frequent forced outages.

As the Cities have shown in their previous comments, the cost of the mitigation fee would be at least 7% and in some cases well over 20% of the total cost of the replacement project. The fee would likely be closer to the higher percentage because, in order to preserve necessary on-site generation and reserves, any replacement project would have to be permitted at a maximum monthly capacity equal to the equipment being replaced (i.e., the existing boilers). By imposing these fees, the District will encourage the Cities to postpone or downsize their replacement projects, thereby losing the emissions benefits and the increased reliability they would provide.

Because each City must plan for loads in excess of historical peaks even with modest load growth, there will be a need for a larger amount of on-site generation and reserve capacity to cover future increased peak demand, partly because of limited import capacity and partly for optimal integration of renewable power sources (e.g., wind, solar and geothermal). We will explain each of these below.

Increased capacity to import power in the future cannot be assumed, because of a reasonable expectation of opposition to the construction of new transmission lines, the lack of new transmission corridors into the LA Basin, and the cost and long lead-times of constructing new transmission capacity. Even with efforts to increase energy efficiency and demand response, cost-effective and reliable local generation must be available for the foreseeable future.

Increasing amounts of renewable power sources also must be integrated into the Cities' power grids. These renewable power sources typically are intermittent, requiring local resources that can cycle on and off as needed. Newer turbines are much preferred as local resources because they are more flexible than the older boilers that now partly perform that function. Thus, in a way, the trend toward increasing renewable power sources creates a corresponding increased need for substantial, flexible local generation. Discouraging boiler replacement in the needed quantities would hamper the Cities' ability to optimally integrate these renewable power sources.

3. <u>Additional concerns re upfront mitigation fee</u>

The five-year upfront payment would come from the Cities' cash reserves because bonds cannot be issued until the project is approved. Therefore, the ratepayers of each City would be responsible for paying this upfront fee with no guarantee that the project will be approved. Because of this, the fee should be 100% refundable if the project is not approved, or the fees should not be due until this approval is granted.

4. <u>Potential constraints on Glendale's borrowing capacity</u>

-

In conversations with District staff, Glendale discussed its concern regarding borrowing constraints that would be aggravated by a substantial mitigation fee. District staff requested clarification regarding those constraints.

-

In order to finance this type of project, Glendale would have to issue debt either directly or through SCPPA. In either case, the additional debt would have an impact on the City's debt service coverage ratio, and could have an impact on the credit rating of the City, and/or of GWP itself. Given this impact, there is a limit on the total amount of new debt that the City can issue, directly or indirectly, and capital-intensive projects inside the City typically "compete" for access to these limited funds. Repowering the Grayson plant by replacing old boilers will compete with improvements to the electric distribution system, information management systems, municipal buildings, and the water distribution system. Significantly increasing the cost of repowering the old boilers at Grayson could easily cause other competing projects to "crowd out" the new generation, thus causing emissions to be higher and local reliability to be worse than they would be with repowering.

We appreciate the opportunity to provide the District staff with this additional information. Please call me if you have any questions.

Charles F. Timms, Jr.

Broiles & Timms, LLP
Attorneys for the Cities of
Burbank, Glendale, and Pasadena

Example 1. BWP calculations for replacing Olive 1 & 2 boilers with and LMS 100 permitted for 1300 hours/year annual operations (<15% capacity factor)
Annual offset fee caculated per proposed AQMD Rule 1304.1
The table below compares the proposed Offset fees for an LMS100 replacement unit with a PTE based on a peak month of 270 or 720 operating hours.

	$F_{i\ for\ 270\ hour/month}$	$F_{i\ for\ 720\ hour/month}$	R_i	$PTE_{rep\ for\ 270\ hr/month}$	$PTE_{rep\ for\ 720\ hour/month}$	OF_i	C_{rep}**	$C_{2yavgexisting}$***	C_{rep}- $C_{2yavgexisting}$/ C_{rep}
PM10	$344,353	$918,275	$7,245	50	133	1.0	130,000	6165	95.26%
SOx	$10,016	$26,710	$2,434	4	12	1.0	130,000	6165	95.26%
VOC	$9,655	$25,747	$436	19	52	1.2	130,000	6165	95.26%
Total Annual Offset fees	$364,024	$970,732							
Initial 5-year payment	$1,820,122	$4,853,660							
Net present value of fees for 30 year project with a 3% CPI increase	$7,288,038	$19,434,767							

Ex 2 boiler vs. LMS100

Example 2. BWP calculation of the difference in pollutant emissions between operating Olive 1 & 2 or a LMS 100 to provide power during peak times for a typical summer
Peaks assumed to last 6 hours/day 4 days/week

Parameter	Olive 1	Olive 2	Olive 1 + 2	Olive Notes	LMS100 (Lake 2)	LMS100 Notes
Owner/Operator	BWP/BWP	BWP/BWP			BWP/BWP	
Year Placed in Service	1958	1963			Future	
Unit Type	Steam	Steam			Simple Cycle Intercooled	
Manufacturer	Riley Stoker	Riley Stoker			General Electric	
Fuel	Natural Gas	Natural Gas			Natural Gas	
Running Hours	2,208	2,208		92 days (Jul, Aug, Sep)	312	peaking only
Maximum Load, MW	50	50		assumed	100	assumed
Heat Rate, BTU/kw-hr	13,500	13,500		assumed as typical	8,400	base load spec
mmBTU/hr	675	675			840	
Weeks	13	13			13	
Days/week	4	4			4	
Hours/day	6	6			6	
MAX Load Hours	312	312			312	
Minimum Load, MW	20	20		assumed as typical	0	
Heat Rate, BTU/kw-hr	13,500	13,500		assumed as typical	8,400	base load spec
mmBTU/hr	270	270			0	
MIN Load Hours	1,896	1,896		balance	0	
TOTAL MW-hrs	53,520	53,520	107,040		31,200	
TOTAL mmBTU	722,520	722,520	1,445,040		262,080	
HHV, BTU/cf	1,050	1,050	1,050	SCAQMD default	1,050	SCAQMD default
TOTAL mmcf	688	688	1,376		250	
ROG, lb/mmcf	5.5	5.5		AP-42 Table 1.4-2	2.69	BACT is 2 ppmv @ 15% O_2
SO_X, lb/mmcf	0.6	0.6		AP-42 Table 1.4-2	0.6	EPA AP-42 Chp 1 Table 1.4-2*
PM_{10}, lb/mmcf	7.6	7.6		AP-42 Table 1.4-2	6.93	EPA Chp 3 AP-42 Table 3.1-2a*
CO, lb/mmcf	84.0	84.0		AP-42 Table 1.4-1	9.42	BACT is 4 ppmv @ 15% O_2
NO_X, lb/mmcf	6.37	6.37		BACT is 5 ppmv @ 3% O_2	9.67	BACT is 2.5 ppmv @ 15% O_2
CO_2 e, lb/mmcf	120,247	120,247		AP-42 Table 1.4-2	121,166	EPA Chp 3 AP-42 Table 3.1-2a*

Ex 2 boiler vs. LMS100

Parameter	Olive 1	Olive 2	Olive 1 + 2	Olive Notes	LMS100 (Lake 2)	LMS100 Notes
ROG, lbs	3,785	3,785	**7,569**		**672**	
SO_X, lbs	413	413	**826**		**150**	
PM_{10}, lbs	5,230	5,230	**10,459**		**1,730**	
CO, lbs	57,802	57,802	**115,603**		**2,351**	
NO_X, lbs	4,386	4,386	**8,772**		**2,413**	
CO_2 e, lbs	82,743,472	82,743,472	**165,486,944**		**30,243,066**	
ROG, tons	1.89	1.89	**3.78**		**0.34**	
SO_X, tons	0.21	0.21	**0.41**		**0.07**	
PM_{10}, tons	2.61	2.61	**5.23**		**0.86**	
CO, tons	28.90	28.90	**57.80**		**1.18**	
NO_X, tons	2.19	2.19	**4.39**		**1.21**	
CO_2 e, tons	41,372	41,372	**82,743**		**15,122**	
GHG Rate, lbs/MW-hr	1,546	1,546	**1,546**	standard is 1,100 lbs/MW-hr	**969**	standard is 1,100 lbs/MW-hr
CO_2 e, metric tonnes	37,532	37,532	**75,064**		**13,718**	

*Emission factors from EPA Document AP 42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point & Area Sources

Link to EPA Emission Facto http://www.epa.gov/ttn/chief/ap42/index.html

Worksheet Title	Description
1304.1 Fee Calculation	This worksheet calculates GWP's proposed 1304.1 Fee cost to replace the existing boilers with an LM6000 Combined Cycle - Potential to emit assumes no monthly limit and is based on pollutant calculations from the "GWP emissions (100 MW)" worksheet. These calculations do not including emissions during startup or shutdown. Average annual MWh output of GWP boilers is based on calculations in the "Boiler MWh" worksheet.
Boilers vs. LM6000	This worksheet calculates the significant reduction in pollutants emitted from the operation of an LM6000 at a 60% capacity factor compared to the operation of GWP's boilers at the maximum NOx-limited capacity.
Boiler MWh	The worksheet calculates the average annual MW hour output of GWP's boilers for the last two years. This information is used to calculate the 1304.1 Fee.
GWP emissions (100 MW)	This worksheet calculates the hourly pollutant emissions from the normal operation of a LM6000 Combined cycle (2+1) 100 MW power plant. It does not include emissions from startups/shutdowns.

Proposed Rule 1304.1 - Cost to Glendale Water & Power of Boiler Replacement Fee

Inputs

		PM10	NOX	SO2	VOC	Sources
R(i)	Annual fee for pollutant (i), in dollars per pound per day	$ 7,245	$ 2,653	$ 2,434	$ 436	AQMD proposed rule
PTE(rep)	Permitted PTE of new unit, in pounds per day	135.02	188.39	11.69	52.42	Black & Veatch, EPA, AQMD
OF(i)	Offset factor, scalar	1.00	1.20	1.00	1.20	AQMD formula for proposed fee
	MWh ratio	0.83	0.83	0.83	0.83	(C(rep) - C(boiler))/C(rep)
C(rep)	Maximum MWh of permitted new generation per year	876,000				100 MW at 100% capacity factor
C(boiler)	Average annual MWh generated by boilers in last two years	152,537				Grayson boilers' historical data

Formula for Annual Fee

F(i) = R(i) * PTE(rep) * OF(i) *((C(rep) - C(boiler))/C(rep))

Calculation of Annual Fee

PM	$ 807,884	
Nox	$ 495,332	
Sox	$ 23,499	
VOC	$ 22,652	
	$ 1,349,367	per year

Calculation of Total Life-of-Project Fees

Upfront	$ 6,746,836
NPV	$ 33,346,250
Total	$ 40,093,086

Proposed Rule 1304.1 - Emissions Increases Due to Proposed Fee

Hypothetical Annual Boiler Emissions (lbs) if NOX Limits Output

	NOX	CO	SO2	VOC	PM
LFG	33,316	24,213	4,945	13,641	27,283
NG	36,684	105,054	750	6,879	9,505
Total	70,000	129,267	5,695	20,520	36,788

Pro Forma Annual Emissions for LM6000 @ 60% Capacity Factor (lbs/year)

NOX	CO	SO2	VOC	PM
41,258	40,182	2,560	11,481	29,569

Emissions Changes due to Replacement of Old Boilers (lbs/year)

NOX	CO	SO2	VOC	PM
-28,742	-89,085	-3,135	-9,039	-7,218

GLENDALE WATER AND POWER
GRAYSON POWER PLANT
BOILER GROSS GENERATION DATA

	2011 Gross MWhrs			2012 Gross MWhrs		
	Unit 3	Unit 4	Unit 5	Unit 3	Unit 4	Unit 5
January	-	-	13,508	-	-	12,533
February	-	153	12,913	-	7,178	6,131
March	-	4,868	9,816	-	11,423	1,955
April	-	-	13,291	-	11,593	-
May	-	2,899	10,937	-	12,150	-
June	-	13,219	-	3,150	7,713	-
July	-	5,993	7,561	6,250	4,287	33
August	-	491	11,645	206	11,139	3,070
September	-	-	11,717	-	3,691	7,977
October	207	-	12,920	-	-	12,445
November	-	3,590	8,651	159	473	12,477
December	-	-	12,726	-	11,672	264
Totals	207	31,213	125,685	9,765	81,319	56,885
Grand Total						305,074

By:R.Chetin

Date: 7/3/2013

GWP emissions (100 MW)

Example 1. LM6000 two-on-one combined cycle configuration

Parameter	LM6000	LM6000 notes
Owner/Operator	GWP	
Year Placed in Service	Future	
Unit Type	Combined cycle	
Manufacturer	General Electric	
Fuel	Pipeline Natural Gas	
Operating hours	1	
Maximum Load, MW	100	assumed
Heat Rate, BTU/kw-hr	8,524	Average Operating Heat Rate
mmBTU/hr	852	
TOTAL MW-hrs	100	for one hour, for calculations below
TOTAL mmBTU	852	for one hour, for calculations below
HHV, mmBTU/mmcf	1,050	SCAQMD default
TOTAL mmcf	0.81	for one hour, for calculations below
ROG, lb/mmcf	2.69	BACT is 2 ppmv @ 15% O_2
SO_X, lb/mmcf	0.6	EPA AP-42 Chapter 3 Table 1.4-2
PM_{10}, lb/mmcf	6.93	EPA AP-42 Chapter 3 Table 3.1-2a
CO, lb/mmcf	9.42	BACT is 4 ppmv @ 15% O_2
NO_X, lb/mmcf	9.67	BACT is 2.5 ppmv @ 15% O_2
CO_2 e, lb/mmcf	121,166	EPA AP-42 Chapter 3 Table 3.1-2a
ROG, lbs/hour	**2.18**	
SO_X, lbs/hr	**0.49**	
PM_{10}, lb/hr	**5.63**	
CO, lbs/hr	**7.64**	
NO_X, lbs/hr	**7.85**	
CO_2 e, lbs/hr	**98,364**	
GHG Rate, lbs/MW-hr	**984**	standard is 1,100 lbs/MW-hr
CO_2 e, metric tonnes/hr	**45**	

GWP emissions (100 MW)

Parameter	LM6000	LM6000 notes

Emission factors from EPA Document AP 42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point & Area Sources
Link to EPA Emission Factors http://www.epa.gov/ttn/chief/ap42/index.html

APPENDIX F

COMMENT LETTERS ON THE DEA AND RESPONSES TO COMMENTS

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 • www.aqmd.gov

August 27, 2013

Charles F. Timms, Jr.
Broiles & Timms, LLP
445 South Figueroa Street, 27th Floor
Los Angeles, CA 90071-1630

Subject: Comment Letter on the Draft Environmental Assessment for Proposed Rule 1304.1 – Electrical Generating Facility Fee For Use Of Offset Exemption

E-mailed and sent via Federal Express on August 27, 2013

Dear Mr. Timms:

This letter acknowledges that the South Coast Air Quality Management District (SCAQMD) has received your comment letter regarding the Draft Environmental Assessment (EA) for Proposed Rule 1304.1 – Electrical Generating Facility Fee For Use Of Offset Exemption. Each comment in your letter has been bracketed and numbered and responses to each comment have been prepared. To comply with Public Resources Code §21092.5 (a) and CEQA Guidelines §15088 (b), which require the lead agency to provide responses to comments no later than 10 days prior to certification of the Final EA, a copy of your comment letter and responses to these comments are enclosed. In addition, your comment letter and SCAQMD responses to the individual comments will also be included in Appendix F of the Final EA for Proposed Rule 1304.1. The Final EA is scheduled to be considered for certification at the September 6, 2013 Governing Board Hearing. Once certified, the Final EA will be available for downloading from SCAQMD's website at: http://www.aqmd.gov/ceqa/aqmd.html.

If you have any questions or need more information on the environmental analysis conducted for this project, please do not hesitate to contact me by phone at (909) 396-2706 or by email at mkrause@aqmd.gov.

Sincerely,

Michael Krause

Michael Krause
Program Supervisor- CEQA Section
Planning, Rule Development and Area Sources

Enclosures

BROILES & TIMMS, LLP

445 SOUTH FIGUEROA STREET, 27TH FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828

STEVEN A. BROILES
CHARLES F. TIMMS, JR.

August 22, 2013

VIA EMAIL (JINABINET@AQMD.GOV AND HPOURZAND@AQMD.GOV) AND U.S. MAIL

Jeffrey Inabinet (c/o CEQA Section)
Henry Pourzand
Planning, Rule Development and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Proposed Rule 1304.1 (Adoption Hearing Set for September 6, 2013) Comments on Draft Environmental Assessment and Socioeconomic Report Cities of Burbank and Glendale

Dear Messrs. Inabinet and Pourzand:

Pursuant to the Notice of Completion of a Draft Environmental Assessment ("Draft EA") dated July 5, 2013, and the notice transmitting Draft Socioeconomic Report ("Draft SR") dated August 2, 2013, the Cities of Burbank and Glendale ("the Cities") hereby submit this comment letter on the Draft EA and Draft SR for Proposed Rule 1304.1.

As we will discuss further below, the Draft EA does not adequately address the potential adverse impacts resulting from any delay that the proposed fee may cause in the development of the Cities' boiler replacement projects. While the Draft EA does appear to adequately quantify the potential adverse emissions impacts resulting from such delay, it fails to adequately discuss feasible mitigation, which should include reducing the applicable fee to eliminate the potential for fee-induced project delay. In addition, the Draft EA does not address the potential adverse reliability impacts from such delay, for the simple reason that the analysis it relies on does not take into consideration the unique reliability issues posed by the Cities' limited interconnections with the regional electric grid. 1-1

Moreover, the Draft SR does not adequately address the potential socioeconomic impacts on the Cities resulting from the proposed fee. As currently drafted, PR 1304.1 would impose a fee ranging from 7% to 14% of the cost of the Cities' boiler replacement projects, with unknown consequences for the Cities' ability to finance the funds required to build these projects or to recoup them in higher electric utility rates from the Cities' customers. In addition, the Draft SR does not reveal how much the District will reduce emissions with the fee proceeds. This omission is important, because it does not allow the Governing Board to compare those reductions with the potential increased emissions resulting from project delay, or to compare the cost-effectiveness of those reductions with other pending or proposed emissions reductions efforts, including Glendale's feed-in tariff ("FIT") for distributed solar power. 1-1 cont.

These significant shortcomings of the Draft EA and Draft SR, along with similar and/or related omissions in the Draft Staff Report, are discussed in more detail below.

1. The Draft EA Appears to Adequately Quantify Potential Adverse Emissions Impacts But Does Not Adequately Discuss Feasible Mitigation

The Draft EA acknowledges that if the proposed fee is adopted, it may cause a delay in the Cities' anticipated boiler replacement projects, which would result in continued operation of the Cities' aging boilers, which have higher emission rates than replacement equipment would have. The Draft EA estimates that, as a "worst-case" scenario, the potential increased emissions of criteria pollutants from the Cities' aging boilers could total 318 lbs/day of PM_{10}, 258 lbs/day of VOC, 140 lbs/day of NO_x and 12 lbs/day of SO_x. See Draft EA at Chapter 4, Table 4-4.

The Cities appreciate this emissions analysis and suggest that the significant negative impacts from delayed boiler replacement projects could be mitigated by reducing or eliminating the fee for smaller boiler replacement projects up to 100 MW, such as those anticipated by the Cities. The reduction or elimination of this fee for smaller projects is important to the Cities because these projects do not benefit from the economies of scale that favor larger 100 MW+ projects that typically serve base load. These smaller projects are critically important given that they would provide less emitting, more efficient power to serve load during peak periods and provide necessary reserves to both conventional and renewable power resources, including standby power required to integrate customer-provided renewable generation (more on that below). 1-2

2. The Wolak Report Does Not Consider the Cities' Unique Reliability Issues

The Draft EA concludes that any delay in the Cities' anticipated boiler replacement projects will not affect the reliability of the electric supply system. See Draft EA at Chapter 4, pages 4-16 and 4-17. This conclusion rests entirely on a report prepared by Dr. Frank Wolak for the District ("Wolak"). Unfortunately, Wolak looked at *regional* reliability impacts and did not take into account the *local* reliability impacts on the Cities in light of their limited interconnections with the regional electric grid. Thus, his analysis and conclusions do not apply 1-3 to the Cities. The availability of alternative resources on a regional basis will not help the Cities address local reliability impacts if the proposed fee results in a delay in their boiler replacement projects and they continue to operate their aging boilers.

1-3 cont.

Attachment 1 to this letter is a critique of some of the important aspects of Wolak's conclusions, as they apply to the Cities. This critique was prepared by Glendale's own expert in this area, Lon L. Peters, Ph.D., Integrated Resources Planning Administrator for Glendale Water and Power.

3. <u>The Draft SR Does Not Accurately Address the Impact the Fee Will Have on the Cities' Boiler Replacement Projects</u>

The Draft SR emphasizes the modest impact that the proposed fee may have on regional electric utility rates. See Draft SR at pp. 3-5. That emphasis may be misleading. The most significant cost problem raised by the proposed fee relates to the financing of the projects that will be burdened by the proposed fee, not the potential impact on rate payers. The proposed fee will increase the cost of the Cities' boiler replacement projects by 7% to 14%. The cost of an anticipated Burbank project will increase by about 7% in order to obtain offsets for PM_{10}, VOC and SO_x emissions. The cost of an anticipated Glendale project will increase by about 14% because Glendale is not in RECLAIM and also must obtain NO_x offsets as well as offsets for the other air contaminants. These additional costs will need to be financed along with rest of the project cost, either up front by a bigger bond issue or over time as regular O&M costs. 1-4

Note that the Draft Staff Report, released on August 7, 2013, understates the cost of the proposed fee on the Cities' anticipated replacement projects. The Draft Staff Report indicates that the proposed fees represent 3% to 5% of the costs of the replacement projects. See Draft Staff Report, Appendix B, Responses to Comments, p. 39. On the contrary, as discussed above and as the Cities have shown, the proposed fee in PR 1304.1 as currently drafted would impose a fee of from 7% to 14% on the Cities' replacement projects.

Moreover, the Draft SR assumes that the proposed fee will be completely passed through to the Cities' electric utility customers. It is not a foregone conclusion that this will occur. The Cities can only increase their rates by action of their respective City Councils. Utility rate cases are very contentious, and proposed rate increases are routinely and vigorously opposed by significant numbers of customers. Rate increases are politically sensitive matters, and the Cities' power departments do not always obtain the increases they request. Therefore it is not appropriate to assume that the cost of the proposed fee will be passed through to customers. Even if it is, there are likely to be detrimental consequences elsewhere in the operations of the power department assets, which the Draft SR does not take into account. For example, as the penetration of distributed solar generation increases, the Cities will need new reliable and flexible local generation that can "follow" (inversely) the variable solar output, and will have to set payments to solar generators that account for the costs of this flexible generation, in order to 1-5

1-5 cont.

meet the statutory requirements. More expensive local generation will discourage the integration of distributed solar generation within the Cities.

In fact, generally speaking, the Draft SR and the proposed fee itself are in conflict with California state policies and statutes regarding the shift to greater reliance on renewable energy supplies. Between now and 2020, both Burbank and Glendale must increase the share of their renewable energy supplies to 33 percent of retail load, from 20 percent currently. In the current session of the state legislature, at least one bill was introduced that would increase this obligation to 51 percent after 2020. The current policy objective will require a greater reliance on conventional generation that can "follow" the variable and intermittent output of solar and wind resources and ensure reliable operations. The proposed fee would unnecessarily increase the cost of replacing the Cities existing boilers with cleaner and more efficient conventional resources that will be required to integrate renewable resources, and may delay these important replacement projects. The District should not adopt regulations that are contradictory to broader energy policy goals. 1-6

4. **<u>The Draft SR Does Not Demonstrate that Fee Proceeds Will be Effectively Spent to Reduce Emissions</u>**

The Draft SR generally discusses the types of activities that will be pursued with the proceeds from the proposed fee. It states, for example, that 20% of the proceeds will be spent on solar photovoltaic projects and 80% of the proceeds will be spent on projects "similar to" mobile source control measures in the 2012 AQMP. See Draft SR at pp. 6-8.[1] The Draft SR, however, does not discuss how effective those activities will be in reducing emissions. That is an important omission, for several reasons.

For one thing, the Governing Board cannot compare the expected emissions reductions with the potential increases that may occur if the Cities' replacement projects are delayed and they continue to operate their aging boilers. The Draft EA estimates that PM_{10} emissions may increase by as much as 318 lbs/day, without any indication how much, if any, of that increase might be mitigated by PM_{10} emissions decreases once the replacement projects are permitted. 1-7

In addition, the Governing Board cannot compare the effectiveness of the proposed expenditures with other, similar expenditures that are already planned in the same area. For example, Glendale recently adopted a FIT for distributed solar power, as required by state law. To the extent the FIT reduces the need to generate power from fossil-fuel powered resources, the City will receive Renewable Energy Credits for use in compliance with the requirements of AB 32. Pursuant to its FIT, the City will offer a little over \$.09 per KWh for peak period distributed

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[1] We note that the specific control measures cited in the Draft SR rely on advancement of technologies to reduce NO_x emissions and are part of what has come to be known as the "black box." See 2012 AQMP, Appendix IV-B. The measures consist largely of financial incentives to accelerate the deployment of cleaner vehicles. In most cases, cost-effectiveness is not estimated.

solar power production.[2] This is based on Glendale's current estimate of avoided costs, as required by California law, and it appears to be in the mid-range of tariffs that other California cities are paying for distributed solar. The Draft SR does not indicate what price the District plans to pay for distributed solar with proceeds from the proposed fee.[3] If the price is higher than Glendale's, then the District may use the proposed fee to incentivize distributed solar projects within the City of Glendale that is simply not cost-effective when measured against Glendale's avoided costs. Ironically, the District plans to fund these incentives with fees charged against the Cities' boiler replacement projects. These are the very projects that would provide the necessary utility standby power that the solar customer would need to integrate the new solar installation into the grid. The Cities must recoup the cost of providing this standby power to their customers, and higher standby costs would be a disincentive to these projects.

The Cities continue to believe that relevant state statutes, and the Governing Board's own resolutions, were intended to require that cost-effectiveness be addressed before the Governing Board should consider adopting a rule such as PR 1304.1. These statutes are called out in the Draft SR, but they are brushed aside with the claim that the proposed rule is not a control measure. But the District staff has indicated that one purpose of the proposed rule is to reduce the size and/or operation of boiler replacement projects. The Draft Staff Report reiterates this purpose, noting that "facilities will have an incentive to take a realistic cap on emissions to reduce the need for offsets." See Draft Staff Report at p. 15. Moreover, Health and Safety Code § 40440.8 would appear to clearly require that cost-effectiveness be addressed in light of the significant adverse air quality impacts acknowledged in the Draft EA.

1-7 cont.

The Governing Board should be troubled that they are being asked to adopt PR 1304.1 before these serious cost-effectiveness questions have been conclusively resolved. The question is fundamental: is it appropriate to impose fees on boiler replacement projects, encourage the continued operation of aging boilers resulting in increases in emissions, and use the fee proceeds in cost-ineffective efforts to reduce emissions in other areas?

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[2] The ordinance adopting Glendale's FIT can be found at the following link: http://www.ci.glendale.ca.us/government/council_packets/Reports_061813/CC_8b_061813.pdf

[3] The Draft Socioeconomic Report uses units of measurement that are simply inscrutable. For example, the final column of Table 6 includes dollar values that are labeled "$/size". The derivation of these values cannot be discerned from the rest of Table 6 or from the note to Table 6. Furthermore, this label is not familiar to the Cities, and does not adhere to industry standards. This table provides no useful information on cost-effectiveness.

Please let us know if you have any questions. We appreciate the opportunity to provide these comments, and look forward to continuing to participate in the rulemaking process and help the District Governing Board make an informed decision on PR 1304.1.

Sincerely,

Charles F. Timms, Jr.

ATTACHMENT 1

CRITIQUE OF THE WOLAK ANALYSIS AS IT APPLIES TO THE CITIES

PREPARED BY LON L. PETERS

In this section, we review the analysis and conclusions of Wolak, Appendix D of the Draft EA. Although Wolak's analysis (see section 5) is a fairly straightforward application of the "shut down rule" to the question of repowering, the conclusions regarding Burbank and Glendale are incorrect for a variety of reasons. Even if the conclusions are relevant and accurate for other boiler owners/operators, they do not apply to the Cities.

In sections 3.1 and 3.2, Wolak refers to the policies of the California ISO (CAISO) that address resource adequacy and long-term procurement plans, concluding that these policies will ensure a reliable supply of power in southern California and therefore that the boilers at issue in this proceeding will be repowered, even with the proposed fee. In section 3.3, Wolak then states that Glendale and Burbank are subject to "similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA [Resource Adequacy] process and LTPP [Long-Term Procurement Plan] process" (p. 9). These "similar" requirements and planning processes are argued to lead to Integrated Resource Plans at the Cities that ensure reliability while minimizing costs to ratepayers.

Although the Cities have prepared "IRPs" in the past, neither City has undertaken the types of analysis that go into the CPUC RA and LTPP processes, for several reasons. Most importantly, Burbank and Glendale are not members of the CAISO; they operate within the Los Angeles Department of Water and Power (LADWP) balancing authority. Further, each City is interconnected to the LADWP system at only one substation. This of course makes reliability planning very different; Glendale and Burbank are actively concerned mainly with <u>local</u> reliability, defined by metrics applicable to retail load within each City's service territory, and are not as involved in nor able to influence investments or operations in the broader interconnected electrical grid of southern California. Wolak's conclusions (p. 11) that the package of state and municipal policies "is extremely unlikely to reduce the reliability of supply of electricity in Southern California or the entire state" does not apply to <u>local</u> reliability in Glendale and Burbank. There could be 10,000 MW of additional, efficient, reliable supply installed in the LA Basin, but neither Glendale nor Burbank could rely on that supply because of the bottleneck at each City's interconnection with LADWP. <u>Local</u> reliability is a function of <u>local</u> generation, not Basin-wide or state-wide generation: neither Burbank nor Glendale can rely on an outside party or resource to keep their respective customers' lights on. Wolak's conclusions about reliability are therefore incomplete and thus cannot be relied on in this context. 1-8

Wolak also concludes, interestingly, that the existence of repowered boilers and boilers in the process of being repowered <u>reduces</u> the "economic viability of additional units to repowering" (p. 10). Wolak concludes that the new, repowered generation in the LA Basin reduces the profitability of future plants, by reducing the expected price at which power can be sold in wholesale markets. This conclusion may or may not be overridden by Wolak's subsequent analysis in section 5, but it nonetheless should not be overlooked. Any conclusions reached under current conditions about the economics of repowering are not reasonable reflections of expected future conditions, and so the conclusions in section 5 are at least called into question.

Wolak's application of the shut-down rule to Glendale and Burbank is inappropriate, because it does not take into account specific facts. First, in Glendale's case, the marginal or variable cost of fuel (landfill gas, or LFG) that is currently burned in the aging boilers at the Grayson power plant is almost zero, because the LFG belongs to the City of Glendale, which makes it available to Glendale Water and Power at a fixed annual royalty fee. This royalty does not change with or depend on the quantity of LFG actually produced at Scholl Canyon or the quantity of energy generated with the LFG at the Grayson power plant in the City. Second, Glendale is not a participant in RECLAIM, but is subject to older, command-and-control limits on NO_X emissions: 35 tons per year. This means that the variable or marginal cost of a pound of NO_X emissions is zero for Glendale, up to the annual limit. These two facts mean that Wolak's <u>assumption</u> that $c_A < c_B$ may not be correct (p. 13). If this assumption is not correct, then the conclusion that the proposed fee will have no impact on the repowering decision is also subject to reasonable doubt.

Wolak's application of the shut-down rule also assumes that the opportunity cost of capital to Glendale and Burbank is low enough to help ensure that $c_A < c_B$. Again, this ignores the reality of municipal finance. In Glendale's case, the City Council has adopted a policy that approximately one-third of new capital investments will be paid for out of current revenues, with the other two-thirds covered by the proceeds of bond sales. Although this policy helps ensure that Glendale's bond rating is relatively high, and thus helps keep the cost of borrowing down, the <u>effective</u> opportunity cost of capital <u>to the retail customers of Glendale</u> is the weighted average of one hundred percent (applied to the one-third of investments that are paid for by current revenues) and about 4.5 percent (applied to the two-thirds of investments paid for by bond proceeds): about 36 percent. This conclusion is consistent with Wolak's argument, in section 6, that these fees will be paid for by ratepayers, and also applies the "economic accounting perspective" of those same ratepayers. That is, the cost of capital to those who will ultimately pay the bills is not the same as the rate at which the utility can borrow money, <u>if</u> those paying the bills have decided, through their electoral processes, to establish policies that rely on current revenues for long-lived capital projects. Given that the fixed cost of the existing boilers is in the low millions per year, the fixed cost of a new combustion turbine, <u>calculated at the appropriate cost of capital</u>, could easily be higher, in fact much higher, than Wolak assumes. 1-8 cont.

However, Wolak's conclusion that ratepayers will, in all cases, pay the entire cost of the proposed new fees is also incorrect. For a privately held company, emissions fees are an operating cost, deducted from gross income before calculating corporate income tax liabilities.

For example, if the marginal corporate income tax rate (federal plus state) is approximately 33 percent, then one-third of the boiler fees will flow to federal and state taxpayers in the form of higher income taxes, *ceteris paribus*. That is, if state and federal expenditures are not reduced as a result of the deductibility of the boiler fee, other taxes will have to rise in order to compensate for the deductibility of the boiler fee. This means that state and federal taxpayers will, in this example, effectively carry one-third of the burden of boiler fees if the boilers belong to privately held corporations. In the case of Glendale and Burbank, which pay no federal or state income tax, there is no ability to shift the new fee to federal or state taxpayers. The entire fee will flow to the retail ratepayers of Glendale and Burbank. This re-emphasizes the conclusion that the opportunity cost of capital is (a) much higher than is assumed in Wolak's estimates, and (b) much higher than it would be for privately owned boilers. Both results undermine Wolak's conclusions.

Section 6 also argues that owners of repowered generation could earn "significant" additional revenues by selling ancillary services. Unfortunately, this argument does not apply to Glendale or Burbank, which are both cut off from ancillary service markets due to the fact that neither is a member of CAISO as well as the nature of the contractual relationship between the Cities and the transmission system of LADWP. Glendale and Burbank do not have the transmission rights that would enable such sales. Therefore, this argument does not apply to the Cities. 1-8 cont.

Wolak concludes (p. 16) that in "virtually all . . . cases" generator owners will decide to repower even with the fee. This allows the possibility that some generation owners will <u>not</u> decide to repower with the fee, or will delay repowering and continue to run the older boilers. Glendale currently operates about 100 MW of boiler capacity, burning LFG and natural gas. Glendale is the exception to Wolak's general conclusions, which Wolak himself admits may occur.

Responses to Comment Letter #1
(Broiles & Timms, LLP, August 22, 2013)

1-1 The comment notifies the SCAQMD that this comment letter is being submitted on behalf of the Cities of Burbank and Glendale ("Cities") for the Draft Environmental Assessment (Draft EA) and the Draft Socioeconomic Report (Draft SR) for Proposed Rule 1304.1. This comment also highlights some concerns with the Draft EA, Draft SR and Draft Staff Report that are presented in more detail further in the letter. Thus, responses to the specific concerns are presented in Responses to Comments 1-2 through 1-8.

1-2 The comment acknowledges that the Draft EA adequately analyzes and quantifies potential adverse emissions impacts that may occur if the proposed fee causes a delay in the Cities' anticipated boiler replacement projects. Also in the comment, the Cities suggest that the adverse impact could be mitigated by reducing or eliminating the proposed fee for smaller boiler replacement up to 100 MW, which they claim that the DEA did not adequately address. The Draft EA, however, did analyze both eliminating or reducing the proposed fee in the form of alternatives to the project as required by the CEQA Guidelines §15126.6 and evaluated in Chapter 5 of the Draft EA. More specifically, the Draft EA provided an analysis of reducing the fee for all projects and eliminating the fee by not approving the proposed project. The No Project (Alternative A) alternative would maintain current requirements and conditions to obtain offsets from the SCAQMD internal accounts if eligible under the Rule 1304(a)(2) exemption. As such, under Alternative A, electrical generating facilities (EGFs) that use the specific offset exemption under Rule 1304(a)(2) would continue the status quo of not paying for the amount of offsets provided by the SCAQMD internal accounts. Alternative D would require EGFs that use the specific offset exemption under Rule 1304(a)(2) to pay a lower fee than listed in the proposed project for the amount of offsets provided from the SCAQMD internal accounts.

As discussed in Chapter 5, implementation of Alternative A would result in no significant adverse air quality impacts. However, Alternative A would not fulfill three out of the four objectives of the project including not recouping the value of the offsets currently provided for free, not maximizing the availability of funds for investment in air quality improvement projects, and not reducing the depletion rate of offsets from the SCAQMD's internal offset bank. By not recouping the value of the offsets and not maximizing funds for investment in air pollution improvement projects, Alternative A fails to further the goals of the Air Quality Management Plan (AQMP) by providing additional criteria pollutant and corresponding greenhouse gas emission reductions. By not reducing the depletion rate of the offsets, the internal offset bank is limited in assisting critical projects such as essential public services including hospitals, school and sewage treatment facilities.

Similarly with a reduced fee, Alternative D would provide less investment in air pollution improvement projects and corresponding emissions reductions. However, Alternative D, would result in less potential significant adverse air quality impacts as compared to the proposed project if boiler replacement projects are delayed. Because established energy reliability plans and existing regulation is expected to allow for the equipment to breakdown, it is anticipated any potential delay in repowering as a result of Alternative D would be temporary. While Alternative D will generate some funds for investment in air pollution improvement projects, it does not achieve the project objective to maximize the availability of funds because the lower fee correlates to less investment than the proposed project.

Both Alternatives A and D would avoid or substantially lessen the potential significant adverse effects of the project and analysis of these alternatives is provided to foster informed decision making and meaningful public participation in accordance with CEQA Guidelines §15126.6(a). Because both Alternatives A and D do not achieve all the project objectives, staff is recommending the proposed project to the SCAQMD Governing Board as achieving the best balance between achieving the project objectives and minimizing the adverse environmental impacts to air quality and GHG emissions, and energy. Ultimately, the approval of the proposed project or one of the alternatives to the project will take place at the discretion of the SCAQMD Governing Board at the public hearing on September 6.

1-3 The Wolak Report analyzed both regional and local reliability impacts of the Proposed Rule. The SCAQMD disagrees with the premise that the proposed fee will delay repowering projects in the Cities (see Wolak Report, Appendix D). Further, as explained in Section 3.3 of the Wolak Report, municipal utilities such as the City of Glendale Water and Power (GWP) and Burbank Water and Power (BWP) are not subject to CPUC oversight, but they have "similar short-term resource adequacy requirements and long-term planning processes, similar to the CPUC RA [Resource Adequacy] process and LTPP [Long Term Procurement Plan] process." Both GWP and BWP also produce an Integrated Resource Plan (IRP), which is a planning document designed to account for future electricity demand while maintaining a high level of reliability and minimizing ratepayer impacts. In 2007, GWP produced an IRP that considered a 10-year planning horizon and concluded that the City had sufficient resources to meet expected loads during that planning horizon. Similarly, BWP produced an IRP in 2006 that considered a 20-year planning horizon and concluded that the City will "meet substantially all of its load growth requirements over the next 20 years with a combination of energy efficiency measures and renewable energy supplies." While the SCAQMD acknowledges that the Cities have a limited interconnection to the grid, Dr. Wolak notes that the fee did not cause this result but rather it was the result of integrated resource planning decisions and that paying a fee is likely to be the least cost solution to ensuring reliable supply of electricity. For a response to the critique prepared by Dr. Lon Peters, please refer to response to comment 1-8.

1-4 This comment states that the Draft Staff Report indicates that the proposed fees represent three to five percent of the costs of the replacement projects, while the Cities of Glendale and Burbank estimate the fee to represent seven to 14 percent of the costs of the Cities' replacement projects. The commenter does not provide any detailed cost of replacement projects, but in the original comment letter, does provide specific PTE levels for the cities of Burbank and Glendale. Therefore, staff relied on installation cost included in Dr. Wolak's analysis, including a specific estimated cost of $115 Million for a 71 MW repower at City of Pasadena's Glenarm Generation Station, which equates to a cost of approximately $1.6 Million per MW. (See Footnote 45 of Dr. Wolak's report). Dr. Wolak also includes a cost estimate of $782 Million for the 600 MW Haynes Generation Station, which equates to $1.3 Million per MW. The three to five percent cost projection in the staff report is based on the estimated single payment using the PTE provided by the commenter and fee rates in the proposed rule, without including any offset fees for NOx, since most cities and EGFs are part of RECLAIM, and therefore NOx offsets are included in that separate program, as is the case with the City of Burbank that is included in the RECLAIM program.

The total estimated fee under Proposed Rule 1304.1 for the 100 MW repower project operating at a 100% Capacity Factor is $7,878,626, which does not include any offest fees for NOx, and considering a project cost of $1.6 Million per MW based on the City of Pasadena repower project, the estimated total cost of the repower project is $160,000,000. Therefore the estimated fee would represent 4.9% of the total repower cost for the City of Burbank repower project, not the 7% noted by the Commenter. This does not include any credit provided for the actual operation of existing steam boilers over the past two years.

However, in the case of City of Glendale that opted to not participate in the RECLAIM program, NOx offset fees will be part of the total fees under Proposed Rule 1304.1. Based on data provided by the Commenter on behalf of the City of Glendale (i.e., the PTE for a 75 MW Turbine operating at 100% capacity factor), the estimated single fee for PM10, SOx, and VOC would be $5,502,411 and the NOx offset fee would be an additional $5,643,974. Using the City of Pasadena's cost estimate of $1.6 Million per MW of repower, the City of Glendale repower project would cost an estimated $120 Million, and the estimated single payment for PM10, SOx, and VOC would be 4.6% of the total repower project, and 9.2% including the NOx offset fee, significantly below the 14% included in the comment. Staff further notes that if the City of Glendale opts to participate in the RECLAIM program, in lieu of paying the estimated NOx offset fees from Proposed Rule 1304.1, the cost of compliance would approximately be the same. This does not include any credit provided for the actual operation of existing steam boilers over the past two years.

1-5 The comment states that it is not appropriate to assume that the cost of the proposed fee will be passed through to the customers. Under response to comment 1-8, Dr. Wolak discusses the contentious nature of rate cases at the CPUC and how they are analogous to municipal rate cases. He concludes that a City Council is more likely to defer to the recommendations of their municipal power departments than the CPUC is to defer to investor-owned utilities. Refer to response to comment 1-8 for a more detailed discussion from Dr. Wolak about how the City Councils are no less likely than the CPUC to approve rate increases and pass the cost of the proposed fee on to the customers.

SCAQMD staff has examined the impact not only in terms of absolute dollars in comparison to the cost of a proposed repower/regeneration project, but in terms of the fee as a percentage of the cost of electricity and as a function of revenue (see Staff Report at pp 32-33; ".... Burbank Water and Power, with generation operating revenues of $202,268,000,[1] would yield an anticipated incremental cost ratio of offset fees compared to generation revenue of $148,109/$202,268,000 = 0.0732% for Example 2A and $315,179/$202,268,000 = 0.156% for Example 2B"). Moreover, Dr. Wolak has examined the issue and has opined that the proposed fee is not a considerable impediment. This is even more so the case for the cities as their proposal is to permit the repowered units at a 100 percent capacity factor, which implicitly suggests that the new units will be operating a significant number of hours each year (and far in excess of the current capacity of the older units). The more the new units operate, the greater the operational cost savings are to the city due to the increase in efficiency of the new units compared to the older units. Additionally, if the Cities generate power in excess of their municipal demand, they will be able to sell that surplus power and turn a profit.

SCAQMD staff's analysis indicates that Proposed Rule 1304.1 does not present a significant obstacle to the permitting of new replacement generation at the cities.

1-6 This comment states that the Draft Staff Report and the proposed fee itself are in conflict with California state policies and statutes regarding the shift to greater reliance on renewable energy supplies. The SCAQMD disagrees with the Cities that the proposed fee will deter investment in cleaner, more efficient units. While the SCAQMD acknowledges that the Cities, like power generators in the rest of the State, have a statutory obligation to achieve a 33% renewable generation portfolio by 2020 in accordance with the Renewable Portfolio Standard (RPS), the proposed fee and the RPS are not incompatible. The proposed rule does not impede the permitting of quick start, load-following electrical generation needed to integrate variable generating sources such as renewables. The Cities' existing portfolio of electrical generation does not allow for such flexibility with the current rankine-cycle units. While the proposed rule will assess a fee if the Cities elect to use the 1304(a)(2) exemption when repowering their old, rankine-cycle utility boilers, the fee is not an economic impediment to repowering that would inhibit achievement of the RPS. Rather, continued operation of the old utility boilers is a much greater impediment to achievement of the RPS.

1-7 The comment alleges that the Draft Socioeconomic Report must assess the cost-effectiveness of the proposed rule. While the commenter acknowledges that the Draft SR explains that the proposed rule is not a control measure, so that a cost-effectiveness analysis is not required, the commenter cites to Health & Safety Code section 40440.8 for the proposition that such an analysis is required. However, section 40440.8(b)(4) states that the SCAQMD must prepare a socioeconomic analysis when adopting a proposed rule that will affect air quality or emissions limitations and that analysis must include "[t]he availability and cost-effectiveness of alternatives to the rule or regulation, as determined

[1] City of Burbank Proposed Annual Budget 2013-2014. Burbank Water and Power, Electric Fund (496), Statement of Changes in Net Assets, Fiscal Year 2013-14 Proposed Budget, ", page 4, Column "Actual FY 11-12.

pursuant to Section 40922." However, Health & Safety Code section 40922 very specifically describes the cost-effectiveness requirement as applicable to the adoption and implementation of a "specific control measure." The proposed rule merely assesses a fee on the use of an existing offset exemption in Rule 1304(a)(2) and does not propose a new control measure. Therefore, the cost-effectiveness analysis is not required.

SCAQMD staff did analyze the economic impact of the rule and potential air quality improvement projects in the socioeconomic analysis. That analysis identified potential projects that could be used as investment alternatives as part of the overall impact assessment of proposed Rule 1304.1 (see socioeconomic report at page 8; "The PR 1304.1 proceeds are used to finance additional costs for clean technologies beyond current regulations. For all the projects, it is assumed that proceeds from PR 1304.1 would be used to pay for the entire incremental capital costs while operating and maintenance expenditures would be subsumed by the direct beneficiaries of these projects.").

The SCAQMD has consistently explained in Working Group meetings and in the Public Workshop that funds generated from the payment of the proposed fees will be used to fund air quality improvement projects consistent with the 2012 AQMP and in the vicinity of the repowering projects. This approach will be executed in a way that is similar to the RFP process for the distribution of AB1318 funds generated by fees paid to the SCAQMD for offsets used for the CPV Sentinel project. Additionally, at the August 16 Stationary Source Committee Meeting, the Executive Officer and Committee Members discussed that, subsequent to the September 6 Governing Board Meeting, the SCAQMD staff will develop a mechanism that will provide details about the expenditure of funds generated by the proposed fee and bring such a mechanism back to the Governing Board for discussion and approval.

Note that the monies are proposed to be used to reduce potential significant adverse air quality impacts through the installation of photovoltaic cells on both residence and commercial buildings and the funding of "black box" projects needed to meet the 8 hour ozone standard. Some of these "black box" projects include zero and near-zero emission technology for the movement of goods and services in the basin. Cost effectiveness not is required to account for these types of projects as they are not regulatory control measures but supplemental projects that the SCAQMD is undertaking to reduce emissions from the proposed project and to aid in the advancement of technology which will facilitate compliance with the 8-hour ozone standard and the new PM2.5 standard.

With regard to the ability for the Governing Board to make a decision based on not knowing the specific emission reduction benefit from the air pollution improvement projects, under CEQA, the lead agency must make reasonable assumptions upon which to base the analysis, but not engage in speculation. The SCAQMD used that standard in evaluating the types of projects that the funds may potentially be used for, but decided that determining the amount of reductions at this point would be speculative. For that reason, the CEQA analysis for the proposed project does not take credit for any such reductions, and presents instead a worst-case adverse impact scenario. This satisfies

CEQA's information disclosure requirements. The project objectives will allow the Governing Board to evaluate the goals of this project as compared to the issues they raise, all of which are discussed in the Draft EA.

1-8 Attachment 1 was prepared by Dr. Frank A. Wolak in response to the letter dated August 22, 2013 prepared by the Cities and the critique of his July 5, 2013 report ("An Economic and Reliability Analysis of the Proposal to Assess a Fee to Access the South Coast Air Quality Management District's Offset Bank") by Lon L. Peters ("the Peters report") attached to the comment letter and bracketed as comment 1-8.

ATTACHMENT 1

Response to Cities of Burbank and Glendale Letter of August 22, 2013

by

Frank A. Wolak
Director, Program on Energy and Sustainable Development
Professor, Department of Economics
Stanford University
Stanford, CA 94305-6072

August 25, 2013

This document responds to the letter dated August 22, 2013 prepared by the Cities of Burbank and Glendale ("the Cities") and the critique of my July 5, 2013 report ("An Economic and Reliability Analysis of the Proposal to Assess a Fee to Access the South Coast Air Quality Management District's Offset Bank") by Lon L. Peters ("the Peters report") attached to the letter. Both the letter by the Cities and the Peters report argue that the Cities face unique reliability issues posed by their limited interconnections with the regional electric grid and will therefore be adversely impacted the South Coast Air Quality Management District's Proposed Rule 1304.1.

The letter and the Peters report claims that the Cities face unique reliability issues are undermined by the fact that there are seven municipal utilities in the South Coast Air Quality Management District (the District), one of which (Pasadena) is adjacent to the City of Glendale, that do not appear to face the similar reliability issues. The cities of Anaheim, Azuza, Banning, Colton, Pasadena, Riverside, and Vernon are all participating transmission owners (PTOs) in the California Independent System Operator's (ISO) control area, which means that their transmission network facilities are jointly operated by the California ISO along with the other PTOs.

Section 3 of the letter notes that, "The Cities can only increase rates by the action of their respective City Councils." It continues, "Utility rate cases are very contentious, and proposed rates increases are routinely and vigorously opposed by significant numbers of consumers. Rate increases are politically sensitive matters, and the Cities' power departments do not always obtain the increases they request." Changing the words "the Cities" to "investor-owned utilities" and the words "City Councils" to "California Public Utilities Commission" accurately describes the experience of California's three investor-owned utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

Rate cases at the California Public Utilities Commission (CPUC) are highly contentious and they are routinely opposed by significant numbers of consumers, but also by many professional intervenors such as The Utility Reform Network (TURN) and Utility Consumers' Action Network (UCAN). The CPUC Intervenor Compensation Program even provides for individuals or groups that participate in these proceedings to receive compensation for the costs associated with that participation. The CPUC also has a Division of Ratepayer Advocates (DRA) whose statutory mission is to "obtain the lowest possible rate for service consistent with reliable and safe service levels." For these reasons, it seems difficult to argue that rate cases filed by the Cities power departments are more contentious and subject to greater scrutiny than rate cases filed by investor-owned utilities.

It also seems reasonable to conclude that City Councils of the Cities will be significantly more likely to accept the recommendations of their power departments than the CPUC is to accept the recommendations of investor-owned utilities. The CPUC has the legal obligation to regulate investor-owned utilities and a $1.4 billion annual budget to hire the expert staff necessary for the task. Moreover, the CPUC regulates multiple electric utilities, as well as telecommunications, natural gas, and water utilities, so it has considerable experience setting prices and determining whether appropriate service reliability standards are met. Setting utility rates is just one of the many tasks of a City Council must undertake. Few, if any, City Council members have the same experience with or expertise in determining whether appropriate utility service reliability standards are met as the CPUC. Hence, it is reasonable to conclude that the City Councils of the Cities will be more likely than the CPUC to approve rate increases that its power departments deem are necessary to maintain a reliable supply of electricity and that the cost of the accessing the District's Offset bank under Proposed Rule 1304.1, if deemed necessary to maintain a reliable supply of electricity to the Cities by their power departments, will be passed on to consumers in their rates.

The Peters report acknowledges that the Cities have prepared Integrated Resource Plans (IRPs) in the past and that they do not participate in the CPUC RA and LTPP processes, two facts I noted in my July 5, 2013 report. However, it is important to emphasize that as customers of the Western Area Power Administration (WAPA), the Energy Policy Act of 1992 requires the Cities of Burbank and Glendale to submit IRPs to WAPA every five years. The current Resource Planning Approval Criteria (10 CFR Part 905) went into effect May 1, 2000. Consequently, the decision of the Cities to operate within the Los Angeles Department of Water and Power (LADWP) balancing authority and be interconnected to the LADWP system at one substation was the result of previous integrated resource planning decisions by the Cities. As discussed above, seven other cities and their municipal utilities within the District made different decisions in the past to ensure a reliable supply of electricity for their citizens.

The Cities are also members of the Western Electricity Coordinating Council (WECC). The WECC is the Regional Entity responsible for coordinating Bulk Electricity System reliability in the Western Interconnection. Through their WECC membership, the Cities can participate in the processes for transmission planning and system operation in the Western Interconnection in order to ensure that their own reliability needs can be met. The inability of Glendale and Burbank to access the potential 10,000 MW of additional, efficient and reliable supply in the LA Basin mentioned in the Peters report is the result of integrated resource planning decisions made in the past by the Cities. Consequently, paying to access the District's Internal Offset Accounts under Proposed Rule 1304.1 to re-power a local generation unit is likely to be the least cost solution to ensuring a reliable supply of electricity for the Cities' customers given these previous integrated resource planning decisions.

The Peters report argues that application of the shutdown rule discussed in my report is inappropriate to apply to Glendale and Burbank because the "marginal or variable cost of fuel (landfill gas, or LFG) that is currently burned in the aging boilers at the Grayson power plant is almost zero, because the LFG belongs to the City of Glendale, which makes it available to Glendale Water and Power at a fixed annual royalty fee." Peters noted, in a conversation on July 16, 2013 with R. Pease of the District, that if the city repowers this generation facility, it will also have to spend over $10 million to upgrade the fuel supply to make the LFG pipeline quality. Peters' argument also fails to recognize that this LFG has an "opportunity cost" in the sense that it has alternative use to being burned in the Grayson power plant.

The City of Glendale is giving up the revenue it could earn from the selling the LFG for this alternative use for each unit of LFG that is consumed in the Grayson power plant. If the price of this alternative use is greater than the net revenue that the City of Glendale could derive from burning this gas in the Grayson facility, then the citizens of Glendale would benefit from selling this gas rather than burning it in the Grayson unit. If this LFG is upgraded to be pipeline quality, then the opportunity cost argument becomes even stronger. The natural gas could be sold at the prevailing price of pipeline natural gas in Southern California.

Peters' second argument that because Glendale is not a participant in RECLAIM the shutdown rule in my report does not apply also fails to recognize the concept of opportunity cost. If a generation unit has a finite annual limit on NO_x emissions, such as the 35 tons mentioned in the Peters report, this annual limit sets an opportunity cost on producing NO_x for that generation unit. The generation unit owner should assign a specific $/ton opportunity cost of NO_x emissions that enters into the variable cost of producing electricity from that unit. When the fuel cost plus NO_x emissions opportunity cost is below the cost to the utility of purchasing replacement electricity, the unit owner should operate, and whenever the sum of these variable costs is above the prevailing cost of replacement electricity, the unit should not operate. The opportunity cost of NO_x emissions for this unit is simply the $/ton price of NO_x emissions that results in 35 tons of emissions from that unit on an annual basis when the above rule for operating the unit is followed.

Once the concept of opportunity cost is recognized for LFG and NO_x emissions, the shutdown rule faced by Glendale and Burbank is not significantly different from that discussed in my report.

The Peters report also seems to argue that the Cities of Burbank and Glendale face a substantially higher cost of capital than investor-owned utilities. He bases his argument on the fact that Glendale has a policy that "approximately one-third of new capital investments will be paid for out of current revenues, with the other two-thirds covered by the proceeds of bond sales." He argues that this results in a cost of capital of 36 percent, which is more than double the cost of capital to California's investor-owned utilities. However, this same paragraph argues that the City of Glendale has relatively high bond rating and is able to borrow money at 4.5 percent rate, which is below that rate that California's investor-owned utilities must pay on their long-term bonds. It is therefore hard to square Peters' argument that the Glendale faces a cost of capital of 36 percent with these facts. If Glendale is able to borrow at a 4.5 percent rate, requiring a 36 percent rate of return on investment would burden the citizens of Glendale with substantially higher than necessary financing costs for new investments. Finally, Peters' argument that Glendale faces a higher cost of capital than investor-owned utilities directly contradicts the well-known argument made by the American Public Power Association (APPA) that municipal utilities have a lower cost of capital than investor-owned utilities.

The Peters report also fails to recognize distinction between the economic incidence of a fee and who ultimately pays for the fee. All revenues received from the sales of electricity are, by definition, paid by electricity consumers. If these revenues cover the firm's costs, which could include a fee to access the District's Internal Offset Accounts and plus an appropriate return on capital invested, then it is necessarily the case that the cost of the fee is recovered from consumers, as I state in my report. However, the economic incidence of the fee is a different issue that my report did not address. For example, a higher price of electricity brought about by the fee may reduce the demand for electricity and thereby shift the incidence of the fee. However, this does not change the basic fact that electricity consumers pay the entire cost of the fee.

The Peters report argues that if Glendale and Burbank were owners of repowered generation units they could not earn revenues from selling ancillary services. Peters noted in his July 16, 2013 conversation with R. Pease that the Cities currently have the ability to sell energy to other entities in the WECC. However, it is important to emphasize that their inability to sell ancillary services is easily addressed. If the Cities qualified their generation units with the California ISO to sell specific ancillary services that the units were physically capable of selling, they could do so. The California ISO allows all ancillary services except for Regulation Reserve to be sold by generation units located outside of the control area. If a generation resource located outside of the California ISO control area is able to comply with the ISO's Dynamic Scheduling Protocol in Appendix M of the ISO tariff, the unit can even sell Regulation Reserve.[1] Moreover, if the Cities joined the California ISO control area, as seven other municipal utilities in the District have done, they could more easily sell both energy and all ancillary services their generation units are qualified to sell in the California ISO markets. Lack of access to transmission rights to sell energy to other entities in California or the WECC should also not prevent the cities from selling energy from units they might re-power. There is an active market for transmission rights that the Cities could use to purchase the necessary transmission capacity to make these sales. In short, there are no long-term barriers to the Cities selling either energy or ancillary services from any generation units they might own now or in the future.

The long-term reliability challenges faced by the Cities are not appreciably different from those faced by other municipal utilities located in the District. The past integrated resource planning decisions made by the Cities appear to have left them with fewer options than other municipal utilities in the District for maintaining a reliable supply of electricity without having to pay to access the District's Internal Offset Accounts. For the reasons, described in my report and elaborated on in these responses to comments, it seems unlikely that the Cities will compromise the reliability of supply of electricity if the least cost approach to meeting its energy needs is to re-power a unit and pay the fee to access the District's Offset Bank which is then passed on to consumers in the Cities.

[1] Section 8.3.2 of Fifth Replacement Electronic Tariff of California Independent System Operator Corporation, available at http://www.caiso.com/Documents/Section8_AncillaryServices_Jul11_2013.pdf.