SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Environmental Assessment:

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs)

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PREFACE

The Draft Environmental Assessment (EA) for the Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs) was circulated for a 45-day public review and comment period from November 2, 2007 to December 18, 2007. One public comment letter was received and minor modifications were made to the Draft EA so it is now a Final EA. Deletions and additions to the text of the Draft EA are denoted using ~~strikethrough~~ and underlined, respectively. The primary changes to the proposed project since the release of the Draft EA are:

- The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when precipitation causes a sewage treatment plant to exceed its design capacity.
- The Executive Officer may approve the burning of more than ten percent natural gas in a land fill or digester gas-fired engine, when it is necessary, if the engine required more natural gas in order for waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- The emission standards for CO and VOC for new electrical generation engines would be increased from 0.10 lb/MW-hr to 0.20 lb/MW-hr and 0.02 lb/MW-hr to 0.10 lb/MW-hr.
- An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2000 ppm. The engines would still be subject to the I&M plans.

These changes were made in response to comments on PAR 1110.2. The first change was made to allow the operations of natural gas engine during emergencies. This would reduce allow the use of more natural gas combustion instead of diesel emergency engines during emergencies. As shown in the air quality analysis natural gas combustion generates less criteria and toxic air pollutants. Since emergency operations are not expected, they are considered speculative and therefore were not analyzed in the Final EA.

The second change would allow the use of more than ten percent natural gas used at sewage treatment plants where heat from ICEs is used for digesters, and when rainfall causes a sewage treatment plant to exceed its design capacity. During rainy weather, air quality is at its best and the impact of the higher emissions should be minimal. During the winter, the facility that uses heat from the ICEs for digesters may need additional natural gas to sustain digester operations. This exception was added since digester operations at sewage facilities are considered an essential operation. Affected sewage treatment plant operators are expected to add a condition to their permits to operate that specify the temperature at which this exception would apply. Emissions were estimated and evaluated in this Final EA. The additional emissions would not be significant neither would they be considered a substantial increase in the severity of an adverse environmental impact that would require recirculation.

The final change was made because manufacturers have stated that it is not technically possible for new electrical generation engines that require permits to meet the CARB 2007 Distributed Generation Emission Standards, which require emission equipment to large central power plants. However, the Engine Manufacturers Association commented that by increasing the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC, some advanced engines may be able to comply. The choice of installing a new engine that complies with the CARB 2007 Distributed Generation Emission Standards and one that complies with the existing PAR 1110.2 with BACT is not expected to affect any environmental topic except for air quality. The revised CO and VOC limits, modified since the circulation of the Draft EA, would still achieve the same NOx reductions as the original proposal, and for an electrical generator without heat recovery, the revised limits will still achieve an 89 percent reduction of CO and a 77 percent reduction of VOC, compared to the current BACT limits for typical new engines. Therefore, altering the CO and VOC limits for new distributed generators is not expected to significantly adversely impact or substantially make any environmental topic found to be significantly adversely impacted in the Draft EA more severe.

These changes are expected to have similar affects on Alternatives B, C and D. Since Alterative A is the No Project Alternative, these changes would not affect it.

Pursuant to CEQA Guidelines §15088.5, recirculation is not necessary since the information provided does not result in new avoidable significant effects.

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CHAPTER 1

EXECUTIVE SUMMARY

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The 2007 AQMP concluded that major reductions in emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) are necessary to attain the air quality standards for ozone and particulate matter (PM10 and PM2.5).

Rule 1110.2 was originally adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC emissions from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent, or; 2) the engines be permanently removed from service and/or replaced with electric motors. The rule was amended in September 1990 to make minor clarifications to the rule language. Rule 1110.2 was then amended again in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule language.

The objective of proposed amended Rule (PAR) 1110.2 at this time is to further reduce NOx, VOC and CO emissions from gaseous and liquid-fueled ICEs. PAR 1110.2 would partially implement the 2007 AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve emission levels equivalent to best available control technology (BACT). The proposed amendments would affect stationary, non-emergency engines and would increase monitoring requirements; reduce the emission standards equivalent to the current BACT; require new electrical generating engines to meet the same requirements as large central power plants; and clarify portable engine requirements. The proposed project would also remove obsolete portable engine requirements from the existing rule.

A Notice of Preparation and Initial Study (NOP/IS) (Appendix D), were prepared pursuant to the California Environmental Quality Act (CEQA). The NOP/IS identified environmental topics to be further analyzed in this document. The NOP/IS identified air quality, hazards and hazardous materials, and solid/hazard wastes as environmental topic areas that may be adversely affected by the proposed project. The NOP/IS was distributed to responsible agencies and interested parties for a 30-day review and comment period from April 26,

[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).
[2] Health & Safety Code, §40460 (a).
[3] Health & Safety Code, §40440 (a).

2007, to May 25, 2007. During that public comment period SCAQMD received two comment letters on the NOP/IS. Comments were received suggesting that the proposed project could also create significant adverse aesthetics and energy impacts. These environmental topic areas, therefore, are also analyzed in this EA. The comment letters and responses to comments are included in Appendix E.

This ~~Draft~~Final Environmental Assessment (EA), prepared pursuant to CEQA Guidelines §15252 and is a substitute document for an environmental impact report. This ~~Draft~~Final EA includes a comprehensive analysis of potential aesthetics, air quality, energy, hazards/hazardous materials, and solid/hazardous waste impacts as a result of implementing the proposed project. Although the NOP/IS only identified as potentially significant adverse air quality, hazards/hazardous materials, and solid/hazardous waste impacts for further analysis in the Draft EA, comments were received on the NOP/IS asserting that the proposed project could also generate potentially significant adverse aesthetics and energy impacts.

Subsequent to the release of the Draft EA changes were made to PAR 1110.2 in response to comments on the proposed amendments. The primary changes to the proposed project since the release of the Draft EA are:

- The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when precipitation causes a sewage treatment plant to exceed its design capacity.
- The Executive Officer may approve the burning of more than ten percent natural gas in a land fill or digester gas-fired engine, when it is necessary, if the engine required more natural gas in order for waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- The emission standards for CO and VOC for new electrical generation engines would be increased from 0.10 lb/MW-hr to 0.20 lb/MW-hr and 0.02 lb/MW-hr to 0.10 lb/MW-hr.
- An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2000 ppm. The engines would still be subject to the I&M plans

~~Any comments received during the public comment period on the analysis presented in this Draft EA will be responded to and included in the Final EA prior to making a decision on the proposed amended rule, the SCAQMD Governing Board must review and certify the EA as providing adequate information on the potential adverse environmental impacts of the proposed amended rule.~~ One comment letter was received from the public during the 45-day public comment period from November 2, 2007 to December 18, 2007. The comment letter and responses to comments are included in Appendix F of this Final EA.

Throughout this document, references to the proposed project or PAR 1110.2 are used interchangeably.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PAR 1110.2 is a "project" as defined by the California Environmental Quality Act (CEQA). CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD's Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures when an impact is significant.

California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu 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 Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD has prepared this ~~Draft~~Final EA to evaluate potential adverse impacts from PAR 1110.2.

CEQA DOCUMENTATION FOR PROPOSED AMENDED RULE 1110.2

This ~~draft~~Final EA is a comprehensive environmental document that analyzes the environmental impacts from the currently proposed amendments to Rule 1110.2. SCAQMD rules, as ongoing regulatory programs, have the potential to be revised over time due to a variety of factors (e.g., regulatory decisions by other agencies, new data, lack of progress in advancing the effectiveness of control technologies to comply with requirements in technology forcing rules, etc.). The other documents which comprise the CEQA record for the currently proposed amendments to Rule 1110.2, include the NOP/IS of an EA for PAR 1110.2 (April 2007).

Notice of Preparation/Initial Study (NOP/IS) of an Environmental Assessment (EA) for the Proposed Amendments to Rule 1110.2, April 2007: The NOP/IS of an EA for the proposed amendments to Rule 1110.2 was released for a 30-day public review period from April 26, 2007, to May 25, 2007. The NOP/IS was released with an Initial Study, which contained a brief project description and the environmental checklist, as required by CEQA Guidelines. The environmental checklist contained a preliminary analysis of potential adverse environmental effects that may result from implementing the proposed amendments. The NOP/IS identified air quality, energy, hazards and hazardous materials, and solid/hazardous waste as the environmental topics that may be adversely affected by the proposed project. This NOP/IS is included in Appendix B of this ~~Draft~~Final EA.

PAST CEQA DOCUMENTATION FOR RULE 1110.2

Rule 1110.2, like other SCAQMD rules and regulations, comprises a regulatory program that changes over time due to advances in technology, regulatory requirements adopted by state and federal agencies, advances in technology not occurring as anticipated, etc. To reflect these changes, Rule 1110.2 has been amended a number of times since its original adoption in 1990. The following subsections describe the type of CEQA documents prepared for past amendments to Rule 1110.2 and summarize the modifications and analyses prepared for those documents. The current EA focuses on the currently proposed amendments to Rule 1110.2 and does not rely on the previously prepared CEQA documents described in the following subsections. The following documents can still be obtained by contacting the SCAQMD's Public Information Center at (909) 396-2309.

Final Environmental Assessment (EA) for Proposed Amended Rule 1110.2, June 2005 (SCAQMD No. 050318MK): A Draft EA for the proposed Rule 1110.2 was released for a 30-day public review period from March 18, 2005, to April 19, 2005. Proposed amendments to Rule 1101.2 included: removing exemption for all agricultural engines except emergency standby engines and engines powering orchard wind machines; adding more recordkeeping requirements; prohibiting use of portable engine generators to supply power to the grid or to a building, facility, stationary source or stationary equipment except in an emergency affecting grid stability; and removing outdated rule language. Rule 1110.1 was rescinded because it is superseded by the requirements of Rule 1110.2. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on June 3, 2005.

Final Subsequent Environmental Assessment for the Proposed Amended Rule 1110.2, November 14, 1997 (SCAQMD No. 970909DWS): Proposed amendments were made to address portable engine requirements under Rule 1110.2 and CARB's Statewide Portable Engine and Equipment Registration Regulation. Significant adverse impacts were identified and evaluated for air quality and energy. The Draft SEA was released for a 45-day public review and comment period from September 10, 1997 to October 28, 1997. No comments were received from the public.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, December 9, 1994: The proposed amendments clarified the meaning of the terms "originally installed" for purposes of determining compliance with the rule. A NOE was prepared for proposed amended Rule 1110.2, because the proposed amendments were administrative in nature and had no significant adverse impacts on the environment.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, August 12, 1994: The proposed amendments clarified the original intent that continuous in-stack CO monitoring system is not required if a continuous in-stack NOx monitoring system is not required. The proposed amendments harmonized Rule 1110.2 and RECLAIM.

Final Environmental Assessment (EA) for Proposed Rule 1110.2, September 7, 1990: The Governing Board requested that staff examine issues during the adoption hearing for Rule 1110.2 and provide recommendations Clarification of monitoring and periodic emission testing for engines over 1,000 bhp was added for NOx and CO emissions. A limited exemption was proposed for up-slope units at winter resort facilities that are operated less than 700 hours per year. Since the circumstances of the original project and the modifications were essentially the same, the Final EA for Proposed Rule 1110.2 was recertified for these changes.

Final Environmental Assessment (EA) for Proposed Rule 1110.2, August 3, 1990 (SCAQMD No. 900622ES): A Draft EA for the proposed rule was released for a 45-day public review period from May 25, 1990, to July 25, 1990. Four comment letters were received and responses were prepared. The EIR identified potential impacts and mitigation measures for water quality, risk of upset, transportation, energy, solid waste disposal, and human health. Significant adverse impacts were mitigated to less than significant. A mitigation monitoring plan was prepared.

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 adverse 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 before making a decision on the project. Accordingly, this ~~Draft~~Final 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.

Additionally, CEQA Guidelines §15124(d)(1) requires a public agency to identify the following specific types of intended uses of a CEQA document:

1. A list of the agencies that are expected to use the EA in their decision-making;
2. A list of permits and other approvals required to implement the project; and
3. A list of related environmental review and consultation requirements required by federal, state, or local laws, regulations, or policies.

To the extent that local public agencies, such as cities, county planning commissions, et cetera, are responsible for making land use and planning decisions related to projects that must comply with the requirements in PAR 1110.2, they could possibly rely on this EA during their decision-making process. Similarly, other single purpose public agencies approving projects at facilities complying with PAR 1110.2 may rely on this EA.

AREAS OF CONTROVERSY

During the public comment period for the NOP/IS and at public meetings held for PAR 1110.2, commentators expressed concerns about several issues. The expense of installing monitoring and emissions control equipment would cause facility operators to replace existing ICEs with alternative technology. Depending on the alternative technology used, it was asserted that PAR 1110.2 could lead to: increased emissions from certain compliance options; eliminating renewable energy sources if operators replace landfill or digester (biogas) ICEs with flares; replacing pumps with electric motors and emergency diesel generators, thus, creating adverse impacts to public services. Commenters stated that limited supplies of diesel fuel could lead to adverse public service impacts if emergencies last for an extended period of time, such as a loss of water when responding to major fire emergencies.

In response to public comments, SCAQMD staff added low-use exceptions from monitoring and future BACT limits, increased the combined horsepower threshold for CEMS to 1,500 horsepower and added several other exceptions which will significantly reduce the number of required CEMS. SCAQMD staff has also committed to conduct a technology assessment in 2010 to evaluate whether or not cost-effective control technologies are available to allow compliance by biogas engines with the final emission compliance limits in the proposed amended rule, avoid the need for biogas flaring, and eliminate or minimize potential adverse impacts identified by the regulated industry. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Based on these adjustments, SCAQMD staff believes that many of the controversial aspects of PAR 1110.2 for biogas and non-biogas facilities can be addressed.

SCAQMD staff asserts that if water agencies choose to replace ICEs with electric motors as a compliance option, it would be more efficient and less costly to use existing natural gas engines as emergency backup equipment than buying new diesel ICEs. Therefore, SCAQMD staff believes that using existing natural gas engines as emergency generators for electric motors would prevent widespread shortages of diesel fuel for emergency backup generators in the event of an extended emergency.

Comments were also received that the NOP/IS only addressed SCR as compliance option for emission control for biogas engines. In response to these comments this EA also evaluates potential adverse secondary environmental impacts from SCR, NOxTech, CL.Air ®, boilers, gas turbines, microturbines, fuel cells, and biogas-to-LNG facilities as potential compliance options.

Commenters were concerned that if multiple engines used biogas that not all engines would be able to run with 10 percent or less natural gas resulting in more flaring of biogas. SCAQMD staff has added an exception that would allow the use of more than 10 percent natural gas if it reduces flaring.

Commenters have expressed concerns about the distributed power emission standards. PAR 1110.2 would implement Senate Bill (SB) 1298 distributed generation emission standards for new electrical generating engines, which was adopted by the California state legislature in 2000. SB 1298 also established a goal to have local districts require permitted distributed generation (DG) equipment to meet BACT levels by the earliest practicable date. These standards have been in effect since January 1, 2007 for DG equipment that does not require a SCAQMD permit.

EXECUTIVE SUMMARY

CEQA Guidelines §15123 requires a CEQA document to include a brief summary of the proposed actions and their consequences. In addition, areas of controversy including issues raised by the public must also be included in the executive summary. This ~~Draft~~Final EA consists of the following chapters: Chapter 1 – Executive Summary; Chapter 2 – Project Description; Chapter 3 – Existing Setting, Chapter 4 – Potential Environmental Impacts and

Mitigation Measures; Chapter 5 – Project Alternatives; Chapter 6 - Other CEQA Topics and various appendices. The following subsections briefly summarize the contents of each chapter.

Summary of Chapter 1 – Executive Summary

Chapter 1 includes a discussion of the legislative authority that allows the SCAQMD to amend and adopt air pollution control rules, identifies general CEQA requirements and the intended uses of this CEQA document, areas of controversy and summarizes the remaining five chapters that comprise this ~~Draft~~Final EA.

Summary of Chapter 2 - Project Description

The objective of the project is to partially implement 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit to current BACT or replace existing equipment with equipment that meets current BACT requirements at the end of a predetermined life span. PAR 1110.2 would also increase rule compliance by better monitoring, recordkeeping and reporting. PAR 1110.2 would implement Senate Bill (SB) 1298 distributed generation emission standards for new electrical generating engines and, address issues raised by EPA with the current Rule 1110.2.

Summary of 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 PAR 1110.2 as identified in the Initial Study (Appendix D). The following subsections briefly highlight the existing setting for aesthetics, air quality, energy, hazards/hazardous materials, and solid/hazardous waste, which were the only environmental areas identified that could potentially be adversely affected by implementing PAR 1110.2.

Aesthetics

ICEs are used for commercial and industrial applications. ICEs can be housed within buildings or placed outside. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

Air Quality

SCAQMD staff conducted a survey in 2005 of non-agricultural, stationary, non-emergency engines. A total of 580 facilities were contacted, and 313 of those facilities responded (54 percent facility response rate). The survey collected data for 631 out of a total of 859 active engines (73.5 percent response rate based on number of engines). The resulting calculated total emissions for all survey engines were scaled up by category to account for the 76.3 percent representation rate.

A program of unannounced compliance testing conducted by SCAQMD's compliance department revealed that, although engines can generally meet emission limits when emission control systems are properly maintained and adjusted as is generally the case at the time of source testing; emissions during normal operation frequently exceed the emission limits. The resulting total calculated excess emissions for all stationary, non-emergency engines in the district are 9,195 pounds of NOx per day, 2,517 pounds of VOC per day and 54,243 pounds of CO per day.

Energy

The combined annual electricity production in Los Angeles, Orange, Riverside and San Bernardino County is 106,311 gigawatt-hours (gW-hours). The natural gas demand for California is approximately 5,732 million cubic feet per day. In 2001, refineries in California processed approximately 655 million barrels of crude oil.

California's Renewable Portfolio Standard (RPS) was developed under Senate Bills 1038, 1078, 1250 and 107. The senate bills require retail seller of electricity to increase the amount of renewable energy they procure by one percent each year until 20 percent of total retail sales are served with renewable energy by 2017.

The Energy Commission's 2003 Integrated Energy Policy Report recommended accelerating that goal to 2010, and the 2004 Energy Report Update further recommended increasing the target to 33 percent by 2020. The state's Energy Action Plan supported this goal. The PUC accelerated the RPS goal, requiring the utilities to obtain 20 percent of their power from renewables sources by 2010 (Senate Bill 107 codified this goal in state law).

On April 25, 2006, Governor Schwarzenegger signed Executive Order S-06-06. The Executive Order established targets for the production and use of biofuels and biopower, and directed state agencies with important biomass connections to work together to advance biomass programs in California, while providing environmental protection and mitigation. The Executive Order S-06-06 targets 20 percent biofuel by 2010, 40 percent by 2020 and 75 by 2050. Governor Schwarzenegger targeted biomass to contribute 20 percent of the 20 percent goal for renewable electricity generated under RPS for the 2010 and the 33 percent goal for 2020.

Hazards and Hazardous Materials

The use, storage and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage and transportation of hazardous materials. Risks of upset concerns are related to the risks of explosions or the release of hazardous substances in the event of an accident or upset conditions.

Solid/Hazardous Waste

Landfills are permitted by the local enforcement agencies with concurrence from the California Integrated Waste Management Board (CIWMB). Local agencies establish the maximum amount of solid waste which can be received by a landfill each day and the operational life of a landfill. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there are approximately 750,846,000 cubic yards (1,250,367,507 tons) of remaining capacity at Class

II and III facilities in Los Angeles, Orange County, Riverside and San Bernardino that accept construction waste. There are three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA, and Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors Buttonwillow and Westmorland have a remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036.

Summary of Chapter 4 - Environmental Impacts

CEQA Guidelines §15126(a) requires that a CEQA document, "shall identify and focus on the significant environmental effects of the proposed project. Direct and indirect significant effects of the project on the environment shall be clearly identified and described, giving due consideration to both the short-term and long-term effects."

The following subsections briefly summarize the analysis of potential adverse environmental impacts from the adoption and implementation of PAR 1110.2.

Aesthetics

In the NOP, SCAQMD staff stated that PAR 1110.2 would not require any new development, but may require minor modifications to building or other structures for retrofit or replacement. The NOP/IS concluded that modified or replacement equipment would not be substantially difference in physical appearance than the other existing commercial or industrial equipment at these facilities. It was concluded that retrofitted, replaced and/or new equipment would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to: trees, rock outcroppings, or historical buildings.

Subsequent to the release of the NOP, some biogas facilities stated they may choose to replace ICEs with biogas-to-LNG facilities, gas turbines, microturbines, boilers, or flares. A technology assessment will be completed in 2010 to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts, including rule changes if needed.

Biogas facility operators may choose to replace existing ICEs with biogas-to-LNG facilities, gas turbines, microturbines or boilers. Turbines, microturbines and boilers are similar in physical characteristics to ICE systems. It is unlikely that replacing ICEs with one of these technologies would modify the visual characteristics of the existing facilities. Because of the size of the biogas-to-LNG facilities, process equipment and truck loading racks, the equipment and truck loading operations may be visible from outside of the facility. In addition, the process equipment may need additional lighting. Therefore, the installation of a biogas-to-LNG facility may significantly alter the aesthetics of an existing facility.

Air Quality

PAR 1110.2 would require the installation and operation of CEMs systems, air to fuel ratio controllers, CO analyzers, replacement of three way catalyst or installation of oxidation catalyst on non-biogas ICEs. Facility operators of biogas ICEs are expected to install retrofit emission control technology, such as oxidation catalyst and SCR or NOxTech systems. However, commenters have stated that the cost of SCR systems may make it more economical to remove the existing biogas ICEs and replace them with an alternative technology (boilers, gas turbines, microturbines, fuel cells, and biogas-to-LNG plants).

Commenters have stated that the cost of monitoring and control technology would make replacing biogas ICEs with LNG facilities, gas turbines, microturbines, boilers, or flares more economical. These alternative technologies could result in increases in some emissions. SCAQMD staff has committed to conduct a technology review in 2010 to verify that feasible control options for biogas engines are available and that ICEs would not be replaced with continuous flaring. If the technology assessment shows the potential for flaring, staff will return to the Governing Board with a proposal addressing any new significant adverse impacts, including rule changes if needed. Therefore, the replacement of ICEs with flares is not analyzed in this report.

Based on cost estimates it was determined that replacing certain non-biogas engines with electric motors would have cost savings over installing emission controls, monitoring and complying with inspection and maintenance (I & M) requirements. SCAQMD staff estimated that 75 percent of the operators with engines that have cost savings would voluntarily replace ICEs with electric motors. The technology assessment in 2010 will evaluate the number of existing ICEs that are voluntarily replaced with electric motors. Emissions from control technology (ammonia slip from SCR) or ICE replacement technology (gas turbines, biogas to liquefied natural gas facilities, etc.), and secondary emissions from delivery or haul trucks, and emergency engines were estimated and evaluated.

Criteria Pollutants

Construction and operational emissions would occur concurrently; therefore, the emissions from both were added together. The resulting emissions were compared to SCAQMD operational criteria pollutant thresholds. The worst-case criteria emissions would occur if all biogas facility operators chose to replace ICEs with gas turbines. In this scenario, PAR 1110.2 would reduce 4,311 pounds of NOx per day, 46,868 pounds of CO per day, 1,995 pounds of VOC per day and 13 pounds of SOx per day. PM10 would increase by 142 pounds per day and PM2.5 would increase by 142 pounds per day. The PM10 increase would be below the significance threshold of 150 pounds per day. The PM2.5 emissions would be greater than the significance threshold of 55 pounds per day. Therefore, PAR 1110.2 would be significant for PM2.5 operational emissions.

Air Toxic Pollutants

Health risk is evaluated on a localized level by evaluating the adverse impacts of a facility on the near-by community. Health risks were estimated from the largest aqueous ammonia emissions associated with SCR at an affected facility, the largest diesel exhaust emissions from diesel emergency generators, and the largest amount of delivery trucks at an affected facility.

Only one of these scenarios would not typically occur at a single facility, since it was believed that biogas facility operators would install the same type of add-on control or ICE alternative technology for all biogas engines at a given facility. Therefore, biogas operators would either install SCR (ammonia), a biogas-to-LNG plant (diesel particulate from LNG trucks) or ICE alternative technology that would require an emergency generator (gas turbines or microturbines). However, some facilities have both non-biogas and biogas engines at the same facility. It is possible that a biogas facility would have emergency engines for both non-biogas electric motors and either SCR, a biogas-to-LNG plant or emergency generators for biogas ICE alternative technology.

The carcinogenic health risk from the facility with the largest number of diesel truck trips would be two in one billion (2.0×10^{-9}), which is less than the significant threshold of ten in one million (1.0×10^{-5}). The carcinogenic health risk from diesel emergencies generators at the largest biogas facility would be 3.4 in one million (3.4×10^{-6}), which is less than the significant threshold of ten in a million. The carcinogenic health risk from the facility with the largest non-biogas emergency engine would be 18 in one million (1.8×10^{-5}), which is greater than the significance threshold of 10 in a million. Therefore, PAR 1110.2 would be significant for carcinogenic health risk from diesel particulate emissions.

Diesel particulate filters have been certified as at least 85 percent efficient for stationary diesel engines. This control efficiency would be enough to reduce the health risk to below the significance threshold of 10 in one million even if the greatest carcinogenic health risk from both the biogas and non-biogas emergency engines at single facilities were added together (3.4 in one million + 18 in one million = 21.4 in one million x (1 – 0.85) = 3.2 in one million). Therefore, diesel particulate filters would mitigate carcinogenic health risk from PAR 1110.2 to not significant.

The chronic non-carcinogenic hazard indices from diesel particulate matter at LNG facilities or facilities with emergency generators would be less than the significance threshold of 1.0. The chronic and acute hazard indices from ammonia slip at the largest facility would be less than the significance threshold of 1.0.

Global Warming

Combustion processes generate greenhouse gas (GHG) emissions in addition to criteria pollutants. The GHG analysis focused on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs are longer-term, affecting global climate over a relatively long time frame. As a result, the SCAQMD current position is to evaluate GHG effects over a longer timeframe than a single day.

SCAQMD staff estimated that replacing certain non-biogas engines with electric motors would generate less cost than complying with the requirements of PAR 1110.2. SCAQMD staff estimated that approximately 25 percent of these 225 engines with cost savings may not be replaced because of reasons other than cost. Therefore, 169 engines were assumed to be voluntarily replaced in the air quality analysis. As a worst-case (gas turbine biogas compliance option) it was estimated that at least 15 non-biogas engines would need to be replaced with electric motors to achieve overall CO2 reductions from PAR 1110.2. It is possible that fewer than 169 non-biogas engines could be replaced with electric motors, but, given the lower costs of installing and operating electric motors, it is likely that at least 15 non-biogas engines or more would be replaced with electric motors.

Energy

Total Energy Impacts

Under the worst-case energy scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants), PAR 1110.2 would reduce natural gas used by at least 181,719 MMBtu per year, which includes the voluntary replacement of existing non-biogas engines with electric motors where it costs less than complying with PAR 1110.2. The total electricity production loss by the worst-case biogas scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants) would be 576,527 MW-hours per year which is less than one percent of 120,194 GW-hours per year available in Southern California. The maximum amount of diesel used in worst-case construction and operations would be 1,871 gallons of diesel per day, which is less than one percent of the 10 million gallons consumed per day in California, and therefore is less than significant.

Renewable Energy Impacts

A technical assessment will be completed in 2010, which will verify that PAR 1110.2 would not cause biogas facility operators to replace existing ICEs with continuous flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Because of the technology assessment under PAR 1110.2, SCAQMD staff believes that facilities operators will either use add-on control or replace ICEs with alternative technologies that would either generate electricity or LNG; there would be only adverse impacts to renewable energy supplies from efficiency losses between the existing ICEs and the ICEs with add-on control or ICE replacement technologies. The largest electrical loss from renewable energy sources because of differences in efficiency between alternative technologies and the existing ICEs would be 101,013 MW-hours per year for the microturbines compliance option.

There may be adverse energy impacts in an individual government program, but any energy losses other than from efficiency losses from one program may be made up in another program. For example, if a landfill gas facility operator chooses to replace an existing biogas ICEs with a LNG facility, not only would there be a loss of electricity generation, but the LNG facility would need energy from the grid to operate. However, the landfill gas would not be wasted, but treated and sold as LNG, which is a renewable fuel. Therefore, while this might affect the California's Renewables Portfolio Standard (RPS), which focuses only on electricity, it would assist renewable fuel/biomass goals under Governor Schwarzenegger's Executive Order S-06-06.

Hazards and Hazardous Materials

Ammonia Impacts

SCR systems require either urea or ammonia. Urea would not result in offsite adverse impacts. The Executive Officer has prohibited the permitting of control technology using anhydrous ammonia. To further reduce hazards associated with ammonia, a permit condition that limits the aqueous ammonia concentration to 19 percent is typically required. Since 20 percent aqueous ammonia is evaluated by CalARP, adverse impacts from aqueous ammonia were evaluated based on the 20 percent aqueous ammonia in this document. The NOP/IS determined that adverse impacts from transport of aqueous ammonia would be less than significant. No comments were received on this analysis so no further evaluation was completed in this document. SCAQMD staff estimated that the largest aqueous ammonia tank would be 5,000 gallons. The toxic endpoint for a 5,000 gallon aqueous ammonia tank would be 0.1 miles. Based on a survey of biogas facilities, some facilities have receptors with 0.1 miles of the existing ICEs. Since it is assumed that aqueous ammonia tanks for SCR system would need to be relatively near to the existing ICEs, it is assumed that the toxic endpoint for aqueous ammonia from a catastrophic failure of the storage tank would significantly adversely affect the receptors within 0.1 miles of the ICEs. Therefore, PAR 1110.2 is significant for aqueous ammonia accidental release.

Liquefied Natural Gas Impacts

Biogas to LNG plants would include LNG storage tanks. Based on the facility survey and design of the LNG facility at the Bowerman Landfill, the largest LNG tank would be 71,000 gallons. The overpressure from a catastrophic release of 71,000 gallons of LNG with a berm was estimated to be 0.2 mile. Based on a survey of biogas facilities, some facilities have receptors with 0.1 miles of the existing ICEs. Therefore, PAR 1110.2 is significant for LNG storage tank accidental release.

Four accidental release scenarios were identified for the transport of LNG: release of LNG into a pool that evaporates and disperses without ignition; the ignition of a flammable cloud, a boiling liquid expanding vapor explosion (BLEVE) occurs, or the tank ruptures, rockets away and ignites. The worst-case endpoint from these scenarios is 0.3 miles from a vapor cloud fire, BLEVE or where rocketing tank would land. Assuming that these accidents would occur near receptors, PAR 1110.2 is significant for LNG accidental release during transport.

The toxic endpoints and overpressures from facilities within a quarter mile of a schools or two miles of an airport or air field would not reach the schools, airport or air field.

Solid/Hazardous Waste

The NOP/IS stated that solid/hazardous waste might be significantly adversely impacted by PAR 1110.2. Adverse solid/hazardous waste impacts are associated with the replacement of ICEs and the disposal of catalysts. The replacement of ICEs would occur once during construction. The replacement of catalyst would occur both during construction and operation. An analysis was completed that compared the capacities of existing solid and hazardous waste landfills and it was determined that the adverse solid/hazardous waste impacts associated with PAR 1110.2 would not be significant.

Potential Environmental Impacts Found Not To Be Significant

The Initial Study for PAR 1110.2 includes an environmental checklist of approximately 17 environmental topics to be evaluated for potential adverse impacts from a proposed project. Review of the proposed project at the NOP/IS stage identified air quality, energy, hazards/hazardous material and solid/hazardous waste for further review in the Draft EA. The Initial Study concluded that the project would have no significant direct or indirect adverse effects on the remaining environmental topics. During that public comment period, SCAQMD received two comment letter on the NOP/IS; however, no comments were received on the NOP/IS or at the public meetings that changed this conclusion. The comment letters and its response are included in Appendix E. However, during the analysis for the Draft EA, SCAQMD staff determined that aesthetics may be significantly adversely impacted by PAR 1110.2. The screening analysis concluded that the following environmental areas would not be significantly adversely affected by PAR 1110.2:

- agriculture resources
- biological resources
- cultural resources
- geology/soils
- hydrology and water quality
- land use and planning
- mineral resources
- noise
- population and housing
- public services
- recreation
- transportation/traffic

Consistency

The Southern California Association of Governments (SCAG) and the SCAQMD have developed, with input from representatives of local government, the industry community, public health agencies, the United States Environmental Protection Agency (USEPA) - Region IX and the California Air Resources Board (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. Analysis of the proposed project shows that it is consistent with the RCPG.

Summary Chapter 5 - Alternatives

Four feasible alternatives to the proposed amended rule are summarized in Table 1-1: Alternative A (No Project), Alternative B (Low-Use Alternative), Alternative C (Compliance Only Alternative) and Alternative D (BACT). A comparison of the potential aesthetic and air quality adverse impacts from each of the project alternatives with PAR

1110.2 is given in Table 1-2. No other significant adverse impacts were identified for PAR 1110.2 or any of the project alternatives. The proposed project is significant for air quality from NOx emission during construction activities; for energy from total and renewable resource electricity adverse impacts, and for hazards/hazardous materials from accidental releases from aqueous ammonia storage and LNG transport and storage.

Alternative A (No Project Alternative)

Since Alternative A is the same as the existing setting, no significant construction emission impacts are expected. There would be no construction, so there would be no construction emissions. One of the primary reasons for amending Rule 1110.2 is to improve compliance with the emission concentrations of the rule by imposing CEMs requirements, inspection and monitoring plan requirements; monitoring, testing, recordkeeping, and reporting requirements; etc. By not amending Rule 1110.2, it is possible that a large number of affected engines would continue to operate out of compliance. NOx, CO and VOC emissions (9,195 lbs of NOx per day, 54,243 pounds of CO per day and 2,517 pounds of VOC per day) would exceed the significance criteria of 55 pounds per day of NOx, 550 pounds per day of CO and 55 pounds per day of VOC. Engines exceeding compliance limits could do so in amounts that exceed applicable SCAQMD significance thresholds. There would be no change in ICE operation so there would be no adverse energy impacts. There would be no change in control or operational equipment so there would be no new aqueous ammonia storage or LNG transport and storage. Because NOx, CO and VOC would be significant for Alternative A, it would not accomplish a major objective of the proposed project which is to further reduce NOx, CO and VOC emissions from ICEs. Since Alternative A does not implement the objective, the proposed project is preferred over Alternative A.

Alternative B (Low Use Alternative)

Alternative B would increase the low-use exception to concentration limits and extend the 15 minute averaging time for compliance limits to one hour. In PAR 1110.2, the low-use exception applies to ICEs that are used less than 500 hours per year or burn less than 1,000 MMBtu per year. Alternative B would increase the low-use exception to 1,000 hours or 2,000 MMBtu per year. Alternative B would include an exception for lean-burn engines from the CEMS requirement. These changes would require less new monitoring and control technology for low-use ICEs and for engines that can meet the compliance limit concentrations, but have fluctuations in concentrations. Alternative B also assumes that 169 non-biogas engines would be replaced by electric motors because there would be a cost savings over complying with PAR 1110.2. While there would be less new control technology installed overall, facility operators who need to install equipment, may still install that equipment at the same rate as proposed in PAR 1110.2. Operational emissions from Alternative B may be greater than PAR 1110.2 because less monitoring and emission controls are added. Therefore, to be conservative it is assumed that the adverse construction impacts from Alternative B would be similar to PAR 1110.2. Aesthetic, energy and hazards/hazardous material adverse impact are expected to be similar to PAR 1110.2 and therefore, significant. PAR 1110.2 would be preferred to Alternative B, because it would reduce more NOx, CO and VOC emissions, while still providing a low-use exemption.

Alternative C (Compliance Only Alternative)

Alternative C would keep the concentration compliance limits the same as the existing Rule 1110.2, but would add compliance requirements. It was assumed that no facilities would voluntarily replace existing ICEs with electric motors under Alternative C. Additional infrastructure and monitoring is not expected to change the visual character of the facility or surroundings, therefore, aesthetics would not be significant. Additional compliance requirements would not generate significant adverse construction or operational air quality impacts. Adverse energy impacts from monitoring equipment and travel associated with additional source test are expected to be minor; therefore, less than significant. Alternative C would have no significant hazards/hazardous material impacts, because hazards would not be generated from increased monitoring and source testing. Alternative C would not generate significant solid or hazardous waste from monitoring or source testing. Therefore, Alternative C would not be significant for any environmental topic. Alternative C would not generate any significant environmental impacts, but would not achieve as much emission reductions nor would Alternative C include the project objective of partly implement 2007 AQMP Control Measure MCS-01 – Facility Modernization.

Alternative D (BACT Alternative)

Alternative D, BACT Alternative, would lower compliance limits to BACT levels (11 ppm for NOx, 30 ppm for VOC and 70 ppm for CO). The compliance dates for the compliance limits were expanded from 2012 to 2014 for biogas engines as a natural life allowance. Alternative D would have adverse environmental impact similar to PAR 1110.2. Alternative D may exacerbate the adverse environmental impacts because larger or additional control may be required to meet the lower CO compliance concentration limits. Alternative D does include the same low-usage exemption as the proposed project. Alternative D would include a mandatory replacement of non-biogas engines for categories where there would be a cost savings over complying with PAR 1110.2. Alternative D would include an exception for facility operators that can demonstrate to the Executive Officer that other considerations would prevent the replacement of the existing ICEs with electric motors where there would be a cost savings over complying with PAR 1110.2. While in practice Alternative D would have greater adverse environmental impacts, the assumptions applied to PAR 1110.2 would also apply to Alternative D. Therefore, for this analysis the adverse environmental impacts from PAR 1110.2 and Alternative D would be similar. Alternative D would be significant for aesthetics, air quality, energy, and hazards/hazardous waste. PAR 1110.2 would be preferable to Alternative D, because the actual adverse impacts from PAR 1110.2 would be less than Alternative D. PAR 1110.2 includes lower CO compliance concentrations and low-use exception, which industry has requested based on cost effectiveness.

Since Alternatives A and C would not achieve proposed project objectives, the proposed project is preferred to Alternatives A and C. Since the proposed project would qualitatively be better than Alternative B, the proposed project is preferred to Alternative B. The proposed project is preferred to Alterative D, because it contains the low-use exception and higher CO compliance concentration limits, which industry has requested based on cost effectiveness. Therefore, the proposed project is preferred over the project alternatives.

Summary Chapter 6 - Other CEQA Topics

CEQA documents are required to address the potential for irreversible environmental changes, growth-inducing impacts and inconsistencies with regional plans. Consistent with the 2007 AQMP EIR, additional analysis of the proposed project confirms that it would not result in irreversible environmental changes or the irretrievable commitment of resources, foster economic or population growth or the construction of additional housing, or be inconsistent with regional plans.

Table 1-1
Summary of PAR 1110.2 and Project Alternatives

Requirement	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Compliance Limits	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 70 ppm CO
Efficiency Correction for Biogas	No	Yes	No	No	No
Averaging Times	15 min	15 min	1 hour	15 min	15 min
Compliance Dates	Emission limits 2010 - 2012 Monitoring 2008 - 2010	N/A	Emission limits 2010 - 2012 Monitoring 2008 - 2010	Monitoring 2008 - 2010	Emission limits 2012 - 2014 Monitoring 2008 - 2010
Natural Life Allowance	None	N/A	None	None	Additional two years to comply with concentration limits
Natural Gas Percentage Limits	10	N/A	10	25	10
Low Usage Exception from Non-Biogas Compliance Limits	Less than 500 hours or less than 1,000 MMBtu annually	None	Less than 1,000 hours or less than 2,000 MMBtu annually	None	Same as PAR 1110.2
CEMS	Stationary ICE groups of 1,500 bhp ICEs or more included in CEMS unless < 500 bhp or operated <1,000 hr/yr or < 8 x 10^9 Btu/year	N/A	Same as PAR 11102, except lean-burn engines are exempt from CEMS requirements	Same as PAR 1110.2	Same as PAR 1110.2

Table 1-1 (concluded)
Summary of PAR 1110.2 and Project Alternatives

Requirement	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Replacement of Existing ICE with Electric Motors	Voluntary	None	Voluntary	None	Mandatory

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

Environmental Topic	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Aesthetics	Significant	Not significant no Impact	Significant less than PAR 1110.2	Not significant	Significant Equivalent to PAR 1110.2
Air Quality					
Criteria	Significant	Significant, greater than PAR 1110.2	Significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Toxic	Significant	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2
Greenhouse Gas	Not significant beneficial effect	Not significant no beneficial effect	Not significant equivalent to PAR 1110.2	Not significant no beneficial effect	Not significant less than PAR 1110.2
Energy					
Electricity	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Natural Gas	Not significant beneficial effect	Not significant less than PAR 1110.2	Not significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Diesel	Not significant	Not significant no Impact	Not significant, less than PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Hazards/Hazardous Material	Significant	Not significant no Impact	Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Solid/Hazardous Waste	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, same as PAR 1110.2	Not significant Equivalent to PAR 1110.2

CHAPTER 2

PROJECT DESCRIPTION

PROJECT LOCATION

The SCAQMD has jurisdiction over an area of 10,473 square miles (referred to hereafter as the district), consisting of the four-county South Coast Air 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 subarea 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 nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion 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 (Figure 2-1).

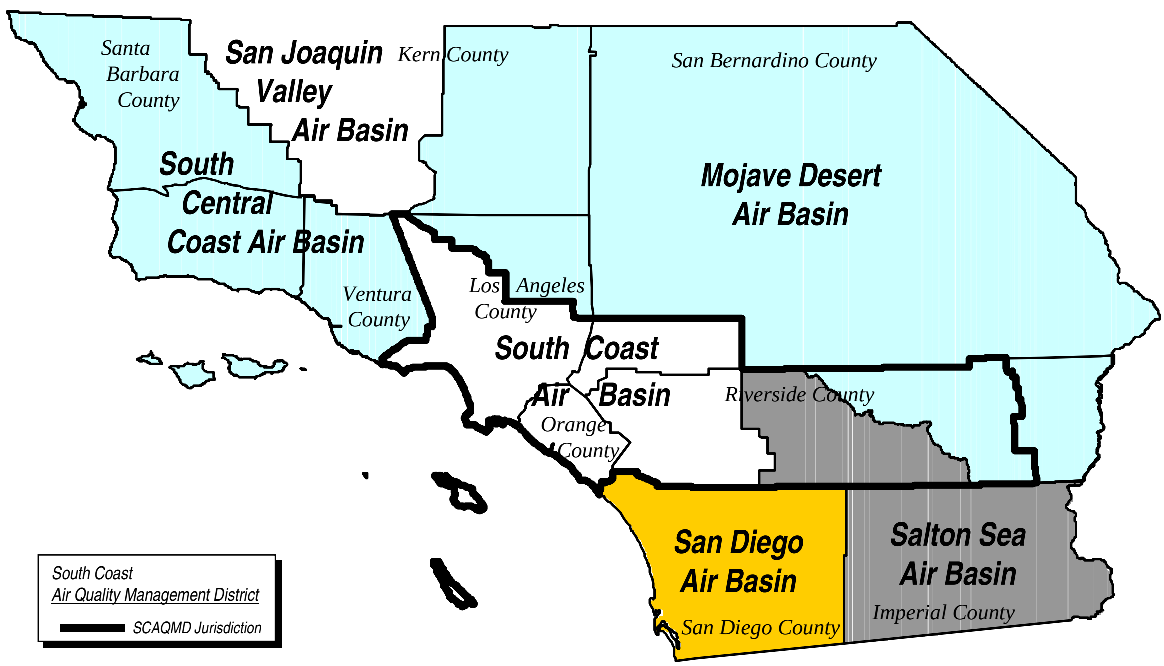

Figure 2-1
South Coast Air Quality Management District

BACKGROUND

Rule 1110.2 was originally adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC emissions from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language. Rule 1110.2 was then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

United States Environmental Protection Agency's Disapproval of Rule 1110.2

SCAQMD rules and regulations are submitted to both the California Air Resources Board and the United States Environmental Protection Agency (EPA) for approval and incorporation into the State Implementation Plan (SIP). EPA proposed the disapproval of Rule 1110.2, which means it cannot be incorporated into the SIP and, therefore, cannot contribute to the SCAQMD's attainment demonstration for state and national ambient air quality standards. EPA recommended the following to enable approval of the rule[4]:

- An inspection and monitoring plan similar to CARB' Reasonably Available Control Technology/Best Available Retrofit Control Technology (RACT/BARCT) document;
- Source testing every two years or 8,760 hours;
- Source testing at peak load as well as at under typical duty cycles; and
- Justification of the exemptions for engines at ski resorts, the far eastern portion of Riverside County, and San Clemente Island.

PROJECT OBJECTIVE

PAR 1110.2 partially implements 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit or replace existing equipment at the end of a predetermined life span to achieve NOx emissions equivalent to BACT. In addition to achieving NOx emission reductions, one of the objectives of PAR 1110.2 is to achieve further VOC and CO emission reductions based on the cleanest available technologies. PAR 1110.2 would also increase engine compliance through improved monitoring, recordkeeping and reporting. PAR 1110.2 would partially implement SB 1298 distributed generation emission standards for new electrical generating engines. Finally, a major objective of PAR 1110.2 is to address issues identified by EPA relative to the existing version of Rule 1110.2, so it can be approved for incorporation into the SIP~~ (see preceding discussion)~~.

REGULATORY BACKGROUND

There are three levels of regulatory requirements that apply to the affected facilities: 1) federal requirements (EPA); 2) state (CARB, and, 3) local (the SCAQMD). The following

[4] Memorandum from Andrew Steckel of EPA to Laki Tisopulos of SCAQMD dated March 31, 2005.

is an overview of federal, state and local regulatory programs that are applicable to the affected operations.

Federal Requirements

The federal Clean Air Act requires the SCAQMD to adopt an AQMP that identifies a control strategy to demonstrate compliance with the federal ambient air quality standards. To address this federal mandate, the 2007 AQMP for the district included AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve emission levels equivalent to BACT. In addition, there are other federal requirements that apply to internal combustion engines. The following is a brief summary of these requirements.

New Source Performance Standards

In a Consent Decree, EPA began working on New Source Performance Standards (NSPS) for new stationary ICEs. EPA recently finalized regulations for compression-ignition (CI or diesel) engines and has proposed regulations for spark-ignition (SI) engines. The Consent Decree requires standards for SI engines to be promulgated by December 2007.

Compression-Ignition Engine New Source Performance Standards (NSPS)

On July 11, 2006, EPA issued final regulations to limit NOx, PM, CO and non-methane hydrocarbon (NMHC) emissions from stationary CI engines, which are contained in Subpart IIII of 40 CFR 60. The compression-ignition (CI) engines NSPS establishes requirements for manufacturers, owners, and operators of new (i.e. engines whose construction, modification or reconstruction began after July 11, 2005) stationary CI engines. The CIE NSPS requires the use of on-engine controls, after treatment and lower sulfur fuel to achieve the same emission standards as required for nonroad engines described in a later section. It also specifies monitoring, reporting, recordkeeping, and testing requirements. Except for CO, the emission standards are not as stringent as the limits in the current Rule 1110.2 until the Tier 4 emission standards go into effect from 2011 to 2015.

Spark-Ignition Engine New Source Performance Standards (SIE NSPS)

On June 12, 2006, EPA issued proposed NSPS for stationary spark-ignition engines (SIE) that would apply to new (i.e. engines whose construction, modification or reconstruction began after a standard is proposed) stationary SI engines. The proposed new Subpart JJJJ of 40 CFR 60 will limit NOx, NMHC, and CO emissions. It also specifies monitoring, reporting, recordkeeping, and testing requirements.

The SIE NSPS requires the use of on-engine controls or after treatment to achieve the emission standards. For all SI engines less than 25 hp, gasoline SI engines and rich-burn propane engines, the emission limits are those in the EPA regulations for nonroad SI engines (40 CFR Parts 90 and 1048).

EPA NOx emission limits have been proposed for large natural gas, digester gas and landfill gas engines that are less stringent than the current Rule 1110.2. Facility operators in the district will be held to the more stringent SCAQMD Rule 1110.2 emission limit. The proposed CO and NMHC limits for the same engines are more stringent than the current Rule 1110.2, but not as stringent as SCAQMD BACT for new engines. The emission limits start at 463 ppmvd CO and 203 ppmvd NMHC and drop to 232 ppmvd CO and 142 ppmvd NMHC by 2010/2011 for natural gas engines[5]. Landfill and digester gas engines are limited to 579 ppmvd CO and 203 ppmvd NMHC.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

On June 15, 2004, the EPA issued a final rule to reduce hazardous air pollutant emissions (formaldehyde, acrolein, methanol, and acetaldehyde) from stationary engines, in the National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP), Subpart ZZZZ of 40 CFR 63. The RICE NESHAP establishes requirements for large (greater than 500 horsepower) stationary engines, both CI and SI, located at major sources of hazardous air pollutants.

The RICE NESHAP requires installation of oxidation catalysts on lean-burn engines and three-way catalysts (also known as non-selective catalytic reduction (NSCR) catalysts) to reduce hazardous air pollutants and CO and specifies recordkeeping, monitoring, and testing requirements. The RICE NESHAP requires that:

- Existing and new 4-stroke rich burn (4SRB) engines either reduce formaldehyde by 76 percent or limit the formaldehyde concentration to 350 parts per billion.
- New 2-stroke lean burn (2SLB) engines either reduce carbon monoxide (CO) by 58 percent or limit the formaldehyde concentration to 12 parts per million.
- New 4-stroke lean burn (4SLB) engines either reduce CO by 93 percent or limit the formaldehyde concentration to 14 parts per million.
- New compression ignition (CI) engines either reduce CO by 70 percent or limit the formaldehyde concentration to 580 parts per billion.

Formaldehyde and CO are surrogates for reducing the air toxics of concern from RICE. Therefore, by reducing formaldehyde and CO, facilities also will reduce other organic air toxics. Similarly, reducing CO will reduce formaldehyde and vice versa.

Only two facility operators within the district have notified EPA that they are subject to the major source RICE NESHAP: the natural gas storage facilities in Northridge and Santa Clarita operated by Southern California Gas Company.

On June 12, 2006, EPA proposed amendments to Subpart ZZZZ that will apply to new or reconstructed RICEs less than 500 hp at major sources, and new or reconstructed RICEs at minor sources. In general these RICEs will only have to comply with the proposed RICE SI NSPS or the adopted RICE CI NSPS. The exception is that new SI 4SLB RICEs from 250 to 500 hp (not including digester or landfill gas fired RICEs) will have to reduce CO by 93 percent or limit the formaldehyde concentration to 14 ppmvd.

Nonroad Engines

EPA regulates new nonroad engines, which include: engines that propel off-road equipment such as trains and bulldozers, and; portable engines that drive generators, wood chippers,

[5] Corrected to 15 percent O2 and assuming an engine efficiency of 30 percent based on higher heating value of the fuel.

and other equipment, and that are moved from place to place. Nonroad engines include CI and SI engines using diesel fuel, propane, gasoline and other fuels.

The Nonroad Preemption

The Clean Air Act Amendments of 1990 limit the ability of states and local districts to regulate nonroad engines. Only EPA can set emission standards for new construction and farm equipment under 175 hp. Federal regulations[6] allow California to regulate all other nonroad engines with an authorization from EPA. Other states cannot regulate the use of nonroad engines, but can adopt California standards.

Nonroad Diesel Engine Regulations

EPA has been regulating new nonroad diesels since 1996 pursuant to 40 CFR 89 Subpart A, Appendix A and 40 CFR 85 Subpart Q. Tier 1, Tier 2 and Tier 3 standards are in effect or are partly in effect and recently adopted and stringent Tier 4 standards will go into effect in the next decade. The emission standards vary by engine size, but as an example Table 2-1 shows the standards for nonroad diesel engines from greater or equal to 100 bhp to less than 175 bhp.

Table 2-1
EPA Nonroad Diesel Engine Emission Standards (grams/bhp-hr)
$175 \leq hp < 300$

Tier	Implementation Date	CO	NMHC	NOx + NMHC	NOx	PM
Tier 1	1996	8.5	1.0	-	6.9	-
Tier 2	2003	2.6	-	4.9	-	0.15
Tier 3	2006	2.6	-	3.0	-	0.15
Tier 4	2012-2014	2.6	0.14	-	0.30	0.015

Nonroad Spark-Ignited (SI) Engine Regulations

EPA regulated new nonroad SI engines over 25 hp since 2004 pursuant to 40 CFR 1048. Most of these engines use liquefied petroleum gas (propane), with others operating on gasoline or natural gas. EPA adopted the two tiers of emission standards shown in Table 2-2. The first tier of standards, which became effective in 2004, is based on a simple laboratory measurement using steady-state procedures. The Tier 1 standards are the same as those adopted earlier by CARB for engines used in California. The Tier 2 standards, which became effective in 2007, are based on transient testing in the laboratory, which ensures that the engines will control emissions when they operate under changing speeds and loads in the different kinds of equipment. EPA includes an option for manufacturers to certify their engines to a less stringent CO standard if they certify an engine with lower HC plus NOx

[6] 40 CFR 89, Subpart A, Appendix A and 40 CFR 85, Subpart Q

emissions. In addition to these exhaust-emission controls, manufacturers must take steps starting in 2007 to reduce evaporative emissions, such as using pressurized fuel tanks.

Table 2-2
EPA SI Engine Emission Standards (grams/bhp-hr)

Tier	Implementation Date	HC + NOx	CO
Tier 1	2004	3.0	37
Tier 2	2007	2.0	4.4

Starting with Tier 2, EPA adopted additional requirements to ensure that engines control emissions during all kinds of normal operation in the field. Tier 2 engines must have engine diagnostic capabilities that alert the operator to malfunctions in the engine's emission-control system.

State Requirements

The California Health and Safety Code also requires the SCAQMD to adopt an AQMP that identifies a control strategy demonstrating progress towards achieving the state ambient air quality standards. The CARB Governing Board adopted the SCAQMD's 2007 AQMP without substantial modification. CARB must submit the 2007 AQMP to EPA for final approval and incorporation into the SIP. The 2007 AQMP includes the control strategy MCS-01 – Facility Modernization, which proposes that existing equipment be retrofitted or replaced with BACT at the end of a pre-determined lifespan. PAR 1110.2 would require that existing ICEs be retrofitted or replaced with equipment that can meet BACT concentration standards.

Senate Bill 1298

Senate Bill 1298[7] was adopted in 2000 by the California state legislature to close a loophole for small electric generators that were exempt from local district permits and not required to have emission controls. In accordance with the law, CARB adopted the Distributed Generation Certification Program[8] for small generators that are exempt from local district permitting requirements. Small generators include ICE generators of 50 hp or less, microturbines, and fuel cells. As of January 1, 2007 these electrical generation technologies may only be sold in California if they are certified by CARB to have emissions equivalent to, or better than large central generating stations equipped with BACT. SB 1298 also established a goal to have local districts require permitted distributed generation (DG) equipment meet BACT levels by the earliest practicable date.

CARB Guidance for Stationary Spark-Ignited Engines

In 2001, CARB published "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines" as guidance for local air districts in adopting rules for stationary spark-ignited engines. Because of compliance problems with engines throughout the state,

[7] Sections 41514.9 and 41514.10 of the California State Health and Safety Code
[8] Sections 94200-94214, in Article 3, Subchapter 8, Chapter 1, Division 3 of Title 17, California Code of Regulations

CARB's publication recommended more frequent source testing than is currently required in Rule 1110.2 and an Inspection and Monitoring Plan requiring periodic monitoring and maintenance, including the use of a portable emissions analyzer.

Air Toxic Control Measures for Diesel Engines

CARB has adopted Air Toxic Control Measures (ATCMs) for both stationary and portable diesel engines. The purpose of these ATCMs is primarily to reduce diesel PM because it has been classified as a carcinogen by CARB. However, the ATCMs often result in emission reductions of other pollutants as well.

Stationary Diesel ATCM – SCAQMD Rule 1470

SCAQMD has adopted Rule 1470 to implement the state ATCM for stationary diesel engines. Rule 1470 requires emergency diesel engines to: limit the annual operating hours for maintenance and testing; avoid operation during school hours when near a school: and install a diesel particulate filter when located within 328 feet of a school. Non-emergency diesel engines, with some notable exceptions, must also install a diesel particulate filter to meet the required emission limit.

Existing stationary agricultural engines were not subject to the original stationary diesel ATCM, but on November 16, 2006, CARB adopted the first of several amendments to the ATCM that make existing stationary agricultural engines subject to the ATCM requirements. The most recent amendments to the ATCM relative to existing stationary agricultural engines have not yet received approval by the Office of Administrative Law. The ATCM requires the following for stationary agricultural diesel engines, not including wind machines, emergency engines, or engines less than50 hp:

- Except for generator sets, uncertified engines from 51 to 750 hp must meet Tier 3 diesel PM emission requirements by December 31, 2010 or December 31, 2011, depending on horsepower. The compliance requirements of this ATCM will cause operators of engines eligible for the January 1, 2014 compliance date allowed by paragraph (h)(12) of PAR 1110.2 to have to retrofit or replace equipment sooner to comply with the ATCM.
- Generator sets, uncertified engines over 750 hp, and Tier 1 or Tier 2 engines must meet Tier 4 diesel PM emission requirements by December 31, 2014 or December 31, 2015, depending on horsepower. By these dates these same engines will already be required to be in compliance with PAR 1110.2.
- Operators must register their engines with local air pollution control districts by submitting detailed information about each engine. The regulation also allows local districts to charge fees for this registration.

Portable Diesel ATCM

CARB adopted a portable diesel ATCM (§§93116 through 93116.5 of Title 17 of the California Code of Regulations) on February 24, 2004, which will have a substantial effect on portable diesel engines, including agricultural portable engines, greater than 50 hp. The ATCM requirements include:

- As of January 1, 2006, any newly permitted portable diesels must be certified to the current model year standards (Tier 2 or Tier 3 depending on the horsepower). However, CARB recently adopted emergency rules to loosen this requirement to allow resident Tier 1 and 2 engines to continue to operate.
- By January 1, 2010, uncertified portable diesels may no longer be used in California.
- Operators of portable diesel fleets must reduce the fleet average PM emissions to increasingly lower levels by 2013, 2017 and 2020 by engine replacements or retrofit of PM control devices.

Agricultural portable engines are subject to this ATCM, although CARB is developing regulations for agricultural portable engines.

CARB Portable Equipment Registration Program (PERP) Regulation

Health & Safety Code §§41750-41755 (Assembly Bill 531), effective January 1, 1996, required CARB to adopt regulations to establish a statewide registration program for portable engines and other equipment. CARB adopted the regulation on March 27, 1997. Portable engine owners or operators may register under the statewide program or get a permit from SCAQMD. Those that register with CARB are exempt from AQMD permits and emission requirements. As of January 1, 2006, newly registered engines must be certified to the current model year emission standards (Tier 2 or Tier 3 depending on the horsepower). However, CARB adopted emergency rules to loosen this requirement to allow resident Tier 1 and 2 engines to continue to be registered. Portable agricultural engines are not eligible for the CARB PERP program.

Off-Road Diesel Engines

CARB began regulating new off-road[9] diesel engines before EPA, but later harmonized its regulations in Title 13, Chapter 9, Article 4 of the California Code of Regulations (CCR) with EPA nonroad diesel emission standards. On December 9, 2004, CARB approved amendments to incorporate EPA Tier 4 standards into state law. The regulation is not final, however, until approved by the Office of Administrative Law. The NOx, non-methane hydrocarbon and PM emission standards will be the same as EPA's, but there are some minor differences in areas other than the emission standards.

Off-Road Spark-Ignited (SI) Engines

CARB has been regulating new off-road SI engines over 25 hp since 2001 in Title 13, CCR, Chapter 9, Article 4.5. In May 2006, CARB adopted standards consistent with EPA for 2007 to 2009 model years, and more stringent standards starting in 2010. The emission standards are shown in Table 2-3.

[9] EPA uses the term nonroad for the same purpose.

Table 2-3
CARB Off-Road SI Engine Emission Standards (grams/bhp-hr)

Implementation Date	Engine Displacement	HC + NOx	CO
2002	≤ 1.0 Liters	9.0	410
2001-2003	> 1.0 Liters	3.0	37
2007-2009	> 1.0 Liters	2.0	3.3
2010	> 1.0 Liters	0.6	15.4

CARB also adopted fleet average emissions standards for forklifts, scrubbers/sweepers, industrial tow tractors and airport ground support equipment. Starting in 2009 fleet operators will have to reduce average HC plus NOx emissions by retrofits or replacements. By 2013, fleet average emissions will have to be reduced to 1.5 to 3.4 g/bhp-hr, depending on the type of fleet.

Distributed Generating Technologies that Meet CARB 2007 DG Standards

Distributed energy resources are small-scale power generation technologies (typically in the range of three to 10,000 kW) located close to where electricity is used (e.g., a home or business) to provide an alternative to or an enhancement of the traditional electric power system. The distributed generating (DG) certification program requires manufacturers of electrical generation technologies that are exempt from district permit requirements to certify their technologies to specific emission standards before they can be sold in California. CARB has certified that the DG equipment shown in Table 2-4 meet the 2007 standards.

Table 2-4
Certified Technologies to CARB 2007 DG Standards

Company Name	Technology
United Technologies Corporation Fuel Cells	200 kW, Phosphoric Acid Fuel Cell
FuelCell Energy, Inc.	250 kW, DFC300A Fuel Cell
Plug Power Inc.	5 kW, GenSys™ 5C Fuel Cell
FuelCell Energy, Inc.	1 MW, DFC1500 Fuel Cell
Ingersoll-Rand Energy Systems	250 kW, 250SM Microturbine
FuelCell Energy, Inc.	300 kW, DFC300MA Fuel Cell
ReliOn, Inc.	2 kW, T-2000 hydrogen-fueled fuel cell
ReliOn, Inc.	1.2 kW, T-1000 hydrogen-fueled fuel cell

The following DG technologies do not require CARB certification because they are normally required to be permitted by the SCAQMD. The following equipment can, however, also meet CARB's 2007 emission standards.

- Kawasaki GPB15X Gas Turbine–1.423 gross MW at ISO conditions (sea level, 59^{o}F), guaranteed emission limits of 2.5 ppm NOx, six ppm CO and two ppm VOC, all dry basis, corrected to 15 percent O2, down to 70 percent of rated load. These emission limits together with heat input of 20.7 MMBtu/hr (LHV) and 53.7 percent waste heat recovery specified by the manufacturer meet the CARB 2007 standards.

- Large combustion gas turbines with combined heat and power (CHP) are similar to the central station combined-cycle power plants that are the basis of the 2007 CARB DG standards.

Facility operators may install other DG technologies such as: zero-emission solar or wind DG. All of the preceding technologies are either inherently low-emission or will have CEMS to assure proper operation of their add-on emission controls.

Local SCAQMD Requirements

ICEs are required to comply with SCAQMD administrative or prohibitory rules such as Rule 203 – Permit to Operate, Rule 401 – Visible Emissions, Rule 402 – Nuisance, Rule 404 – Particulate Matter- Concentration, and Rule 405 – Solid Particulate Matter – Weight. In addition to Rule 1110.2, other rules that control emissions from ICEs are summarized in the following subsections.

Regulation XIII

Federal and state laws require the development and implementation of New Source Review (NSR) programs to ensure that the operation of new, modified, or relocated stationary emission sources in nonattainment areas does not interfere with the attainment and maintenance of National Ambient Air Quality Standards (NAAQS). Local NSR programs must, at a minimum, comply with the requirements established pursuant to federal and state law. The general requirements of NSR programs include: (1) pre-construction review; (2) the installation of air pollution control equipment; and, (3) the mitigation of emission increases by providing emission offsets.

To satisfy requirement (2), the SCAQMD requires BACT for any emissions increase greater than one pound per day from a new, modified, or relocated source within the district. BACT has historically been defined in SCAQMD NSR rules as the most stringent emission limit or control technology which has been achieved in practice for that category or class of source; or contained in a SIP; or other limit that is technologically feasible and cost-effective. SCAQMD rules require BACT for all sources to be at least as stringent as the lowest achievable emission rate (LAER) as defined in the federal Clean Air Act (CAA).

Rule 1470

Rule 1470 applies to stationary compression ignition engines which are engines that remain in one location for 12 months or longer. Rule 1470 primarily regulates DPM emissions by establishing fuel use specifications, operating requirements and PM emission limits for existing diesel-powered engines. Rule 1470 also established emission standards for new stationary diesel engines less than or equal to 50 brake horsepower (bhp) installed after January 1, 2005 based on Title 13 §2423. Title 13 §2423 includes emission standards for NOx, VOC, NOx and VOC combined, CO and PM. Rule 1470 also includes recordkeeping, reporting and monitoring requirements, a compliance schedule, test methods and exemptions.

Although Rule 1470 is based on CARB's ATCM, it contains more stringent requirements for stationary diesel-fueled emergency standby and prime engines located on school grounds or 100 meters or less from existing schools, resulting in reduced emissions of DPM and cancer risk to neighboring schools. Rule 1470 also prohibits non-emergency use (e.g., testing) of diesel emergency standby engines located on school grounds or 100 meters or less from existing schools when school activities are taking place.

Regulation XX – RECLAIM

In 1993 SCAQMD adopted Regulation XX – RECLAIM. This regulation established a cap-and-trade NOx and SOx trading market, with declining annual emission reduction requirements, regulating more than 300 of the largest NOx and SOx sources in SCAQMD's jurisdiction. Operators of affected facilities are exempt from the requirements of specified NOx and SOx stationary source-specific SCAQMD Rules. The program allows facility operators flexibility with regard to complying with the declining NOx and SOx annual allocations, either through installing air pollution control equipment, purchasing RECLAIM trading credits, or a combination of the two.

RECLAIM facility operators are not subject to the source-specific NOx control requirements of Rule 1110.2. RECLAIM facility operators may decide as part of their compliance options to comply with their annual allocation under the program to install air pollution control equipment on ICEs. Although ICEs in the RECLAIM program are not subject to Rule 1110.2 NOx emission control requirements, they are still subject to the VOC and CO emissions control requirements of Rule 1110.2.

SCAQMD BACT Guidelines

NOx, CO and VOC emission levels for stationary engines that are required by SCAQMD's non-major source BACT guidelines are shown in Table 2-5. These limits are typically met by rich-burn engines with a three-way catalyst (TWC), along with an air-to-fuel ratio controller (AFRC). Lean-burn engines generally come with low-NOx combustion modifications built into the engine by the manufacturer to reduce the emissions and then use SCR plus oxidation catalyst to reduce emissions to BACT levels.

Table 2-5
SCAQMD BACT Guidelines for Stationary Engines at Non-major Polluting Facilities

	PPMVD, corrected to 15% O2					
	Uncontrolled Emission		BACT		Percent Reduction by Control Technology	
Criteria Pollutant	Rich-Burn	Lean-Burn	Rich-Burn (NSCR)*	Lean-Burn (SCR + CatOx)	Rich-Burn (NSCR), %	Lean-Burn (SCR + CatOx), %
NOx	590	1090	10	9	98+	99+
CO	1629	136	69	33	95+	75+
VOC	23	91	29	25	---	73+

*Assuming engine is 30 percent efficient (HHV basis).

PROJECT DESCRIPTION

Summaries of the proposed amendments to Rule 1110.2 by subdivision are provided in the following subsections. A copy of PAR 1110.2 can be found in Appendix B.

Applicability

PAR 1110.2 applies to all stationary and portable engines over 50 rated bhp.

Definitions

This subdivision lists keywords related to gaseous- and liquid fueled engines and defines them for clarity and to enhance enforceability. A new definition for “oxides of nitrogen” and revised definition of “approved emission control plan” and engine are proposed to simply clarify the intent of the rule. New definitions for “net electrical energy”, “operating cycle”, “rich-burn engine with a three-way catalyst”, “lean-burn engine” and “useful heat recovered” were developed to support the new requirements discussed later.

The definition of “engine” is revised to clarify that engines used to control VOC emissions from soil vapor extraction are subject to Rule 1110.2.

Requirements

Operators of affected operations would be required to comply with the following requirements by January 4, 2008 unless otherwise stated.

Stationary Engines

Reduction of the Emission Concentration Limits

Subparagraphs (d)(1)(B) and (d)(1)(C) currently limit NOx, VOC and CO concentrations to 36 (less than 500 bhp) or 45 (greater than 500 bhp), 250 and 2000 parts per million, dry volume (ppmvd) respectively for non-biogas-fired (non-landfill/non-digester gas) engines. The proposed amendments will reduce these limits by 2010 or 2011 to levels comparable to current BACT (see Table 2-6). This section provides a new exception from concentration limits effective on and after July 1, 2010 for engines that operate less than 500 hours per year or use less than $1x10^9$ Btu per year of fuel. For two stroke engines with oxidation catalyst and insulated exhaust ducts and catalyst housing, case-by-case CO and VOC limits may be established by the Executive Officer with USEPA approval.

Revisions to the Efficiency Correction for Stationary Engines

The current rule in subparagraph (d)(1)~~©~~(c) allows most stationary engines listed in Table III of the rule, to upwardly adjust the NOx and VOC ppmvd emission limits based on the actual engine efficiency or the manufacturer’s rated efficiency. More efficient engines are allowed higher ppmvd limits.

The proposed amended subparagraph (d)(1)~~©~~(c) limits the efficiency correction to biogas-fired engines, requires that the correction be based on actual efficiency from (American Society of Mechanical Engineers) ASME test procedures, requires engines to use at least 90 percent biogas on a monthly basis, and requires the corrected emission limits to be stated on the operating permit. An allowance for burning more than 10 percent natural gas is provided if the only alternative to limiting natural gas to 10 percent would be shutting down engine and flaring more landfill or digester gas. In response to comments, several changes have been made to PAR 1110.2. The Executive Officer may approve more than the 10 percent natural gas if the 10 percent limit would result in more biogas flaring; or if more than 10 percent natural gas is required in order for an engine's waste heat boiler to provide enough thermal energy for a sewage treatment plant, and if other boilers are unable provide the needed thermal energy. Also, the 10 percent limit will be based on a facility average, rather than for each individual engine. Finally, the calculation of the monthly facility average natural gas percentage may exclude natural gas used during the following situations: during: electrical outages; during Stage 2 or higher electrical emergencies called by the California Independent System Operator; and when rainfall causes a sewage treatment plant to exceed its design capacity. Once an engine complies with the emission limits effective July1, 2012 there will be no limit on the percentage of natural gas burned.

Table 2-6
Proposed Concentration Limits for Non-Biogas Engines

CONCENTRATION LIMITS FOR NON- BIOGAS-FIRED ENGINES			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	36 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	11 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
All Engines	11	30	250

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.

©

Emission Standards for Biogas Engines

In addition to allowing biogas engines to continue to use an efficiency correction factor, the following emission concentration limits are proposed for biogas-fired engines:

Table 2-7
Proposed Concentration Limits for Biogas Engines

Concentration Limits For Landfill and Digester Gas-Fired Engines			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
Concentration Limits Effective July 1, 2012			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
All Engines	11	30	250

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.
3 ECF is the efficiency correction factor.

Initially, only the VOC limit for landfill gas engines would change, to be consistent with other current requirements. In 2012, the emissions limits would drop to BACT levels, just as is proposed for non-biogas engines, except for CO. These emission limits would become effective provided that SCAQMD staff conducts a technology assessment and reports to the Governing Board by July 2010.

Air-to-Fuel Ratio Controllers

The current rule doesn't require an air-to-fuel ratio controller (AFRC) for ICEs. The proposed amendments require ICEs without a CEMS or a Regulation XX (RECLAIM) approved CEMS to install an AFRC with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and USEPA.

Emission Standards for New Non-Emergency Electrical Generation Engines

New non-emergency electrical generation engines are proposed in subparagraph (d)(1)(F) to be subject to the emission standards in the following table.

Table 2-8
Proposed Emission Limits for New Electrical Generation Engines

Pollutant	Emission Limit (lbs/MW-hr)
NOx	0.07
CO	0.2 ~~0.10~~
VOC	0.10 ~~0.02~~

These emission standards do not apply to biogas engines or engines installed before the date of rule adoption or for which an application has been deemed complete before October 1, 2007 and engines installed by an electric utility on Santa Catalina Island. In addition, notwithstanding Rule 2001, these emission standards do not apply to NOx emissions from new non-emergency engines driving electrical generators subject to Regulation XX (RECLAIM).

For engines that do not produce combined heat and power (CHP), the emission standards are based on the net electrical megawatt-hours (MWe-hours) produced. CHP (also know as cogeneration) engines may also take credit for the thermal megawatt-hours (MWth-hours) of useful heat produced, with one MWth-hour for each 3.4 million British thermal units (BTU). The thermal energy could take the form of hot water, steam or other medium.

For CHP engines, the operator will choose short-term emission limits in pounds per MWe-hours that the engine must meet at all times. The operator will also choose an annual electrical energy factor (EEF), such that when the short-term emission limit is multiplied by the annual EEF, the result does not exceed the values in the Table 1-3. The EEF is the annual net electrical energy produced divided by the sum of the electrical and thermal energy produced. The operator will have to also meet the annual EEF limit.

Portable Engines

Staff proposes to remove the emission limits and related requirements for portable engines in subparagraph (d)(2)(A) and add a reference to the California Air Resources Board (CARB)-adopted, portable diesel (Airborne Toxic Control Measures) ATCM and the Large Spark-Ignition Fleet Requirements, to which some portable engines are subject.

Compliance

Paragraphs (e)(1) and (e)(3) are proposed for deletion because they are not necessary. New paragraph (e)(2) includes schedules that will allow time for review and approval of applications for permits to construct, CEMS application, and I&M plan applications. Public agencies will be allowed one more year than the dates on the rule schedule for CEMS applications except for landfill or digester gas engines. New paragraphs (e)(3) through (e)(7) propose compliance schedules for non-agricultural engines required to meet the future emission limits, the stationary engine continuous emission monitoring system (CEMS) requirements, and the inspection and monitoring (I&M) plans. .

New engines will be required to comply with the new CEMS and I&M requirements when they begin operation.

Facilities with more than five engines without air-to-fuel ratio controllers are allowed an additional three months to install equipment on up to half of affected engines. The other facility operators that need to install AFRCs would follow the regular schedule which is one year from the date of rule adoption. An exception has been added for facilities that will be removing engines from service or replacing with electric motor and will not be required to comply with the earlier steps of this subdivision.

Monitoring, Testing and Recordkeeping

The primary focus of the proposed amendments in this subdivision is to improve the poor compliance record of stationary engines.

Additional CEMS Requirements

The existing subparagraph (f)(1)(A) requires 1,000 hp engines and larger, that produce two million bhp-hours per year or more to have a NOx CEMS that measures and records exhaust gas concentrations both uncorrected and corrected to 15 percent oxygen on a dry basis and have data gathering and retrieval capability approved by the Executive Officer. The proposed amendments add CO emissions monitoring back into the rule in subparagraph (f)(1)(A), as it was before the 1997 amendment, but only for rich-burn engines.

In addition, the CEMS requirement will be extended to stationary engines at facilities with multiple engines at the same location (within 75 feet of each other, measured from engine block to engine block) that have a cumulative stationary engine horsepower rating of 1,500 bhp or more. However, the following engines will not be counted toward the cumulative hp rating: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1,000 hours per year or a combined fuel usage of less than 8 x 10^9 Btu per year (higher heating value); and engines already required to have a CEMS.

To avoid circumvention of the requirements, groups of existing engines within 75 feet are based on their location on October 1, 2007. New engines must not be located farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that there is a space limitation or operational need.

Also, in cases where an operator has multiple engines for reliability purposes, with some as standby, the proposed rule would not require a group of engines to have a CEMS if there are permit conditions that limit the simultaneous operation in such a way that the maximum combined rating does not exceed 1,500 bhp.

The 500 bhp exception will reduce the number of new CEMS to less than 100. The other exceptions may reduce the number further, but staff isn't certain by how much.

Lean-burn engines are excluded from the requirement of a CO CEMS. Also excluded from a CO CEMS are engines in RECLAIM that are not required to have a NOx CEMS by Regulation XX.

To reduce the cost, the CEMS can be time-shared between all engines < 1000 hp.

Clause (f)(1)(A)(ix) will allow current CEMs operators to take their CEMS out of operation for up to two weeks in order to add the required CO CEMs.

New clauses (f)(1)(A)(vi) and (f)(1)(A)(vii) provides several exceptions to Rule 218 for the required new CEMS to make timesharing more feasible, and streamline the requirements. They include: allowing digital storage of data, instead of a strip chart; requiring relative accuracy testing on the same schedule as source testing, instead of annually. For timeshared CEMS, they include: requiring a 15-minute sampling time for each timeshared engine; allowing unequal sample line lengths; reducing the minimum number of relative accuracy tests to five for each engine; reducing cylinder gas audits to quarterly; not requiring NO2 monitoring for rich-burn engines; allowing daily calibration error (CE) tests at the analyzer instead of at the probe tip, except for once per week (not requiring CEMS operation or calibration when there is a continuous record of engine non-operation.

Source Testing for Stationary Engines

The current requirement of subparagraph (f)(1)(C) is that emissions testing be done once every three years. The proposed amendments increase the frequency of source testing to every two years, or 8,760 operating hours, whichever occurs first. The testing frequency may be decreased to once every three years if an engine has not operated more than 2,000 hours since last source test.

In addition, the following source testing reforms are proposed:

- Emissions must be tested at for at least 15 minutes at peak load and for at least 30 minutes during normal operation. The source test can no longer be at one load under steady state conditions, unless that is the typical duty cycle. In addition NOx and CO must be tested for at least 15 minutes at actual peak load and actual minimum load. These two tests will not be required if the permit limits the engine to operating at one load.

- Pretests to determine if the engine needs repairs will not be allowed.
- The test must be conducted at least 40 operating hours or one week after any engine tuning or maintenance.
- If a test is started and shows non-compliance, it may not be aborted to allow engine tuning or repairs. The test must be completed and reported.
- A source testing contractor approved by SCAQMD must be used.
- A source test protocol must be submitted and approved by the District at least 60 days before the test is conducted. The protocol will also identify the critical parameters that will be measured during the test, as required by the Inspection and Maintenance Plan (discussed later). If longer than 60 days is needed to approve a protocol more time may be allowed to conduct test.
- SCAQMD must be notified of the test date.
- The test report must be submitted to SCAQMD within 60 days of the test date. This will assure that noncompliance will be reported.
- The operator must provide source testing facilities including sampling ports in the stack, safe sampling platforms, safe access to sampling platforms, and utilities for test equipment. Agricultural engines at remote locations that comply with California General Safety Orders are excused from this clause. Agricultural engines on wheels and moved to storage during the off-season are excused from this requirement.

Inspection and Monitoring (I&M) Plan for Stationary Engines

An I&M Plan will be added to the rule in subparagraph (f)(1)(D). Except for engines monitored by a CEMS, stationary engine operators will submit to SCAQMD for approval an I&M Plan application for each facility to assure continued compliance of the engines between source tests. The I&M Plan will include identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This will include:

- Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller and loads;
- Procedures for verifying the AFRC is controlling the engine to the set point during the daily monitoring;
- Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer;
- For engines with catalysts, maximum allowed exhaust temperature at the catalyst inlet per manufacturer specifications;
- For lean-burn engine with selective catalytic control devices, minimum exhaust temperature at the catalyst inlet for reactant flow and procedures for using portable NOx and oxygen analyzer to establish acceptable reactant flow rate as a function of load;
- Procedures for at least every 150 operating hours, emissions checks by a portable NOx, CO and oxygen (O2) analyzer. The schedule can be reduced to monthly, or every 750 operating hours if three consecutive weekly tests show compliance. If the monthly test

is non-compliant or for rich-burn engines with three-way catalyst the oxygen sensor is replaced, then weekly tests must be resumed. For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMS, the CO emission check will be quarterly or every 2000 engine operating hours. In order to be representative of actual operation, the test will be conducted at least 72 hours after any engine or control system maintenance or tuning. Within 48 hours of finding an operating parameter out-of-range an additional emission check will need to be conducted. The portable analyzer will be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the SCAQMD's "Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Sources Subject to South Coast Air Quality Management District Rule 1110.2"

- Procedures for at least daily recordkeeping of monitoring data and actions required by the plan, including formats of the recordkeeping of engine load or flow rate, set points, and the maximum and acceptable ranges of parameters identified by clause (f)(1)(D)(i), elapsed time meter hours, and hours since last emission check required;
- For rich-burn engines with TWCs, the difference of the exhaust temperature at the inlet and outlet of the catalyst which can indicate changes in the effectiveness of the catalyst;

An I&M Plan will not be required for an engine if it is required by this rule to have a NOx and CO CEMS or voluntarily has a NOx and CO CEMS.

Operating Log

Because dual-fuel engines may consume both liquid and gaseous fuels, proposed paragraph (F)(1)(E) is proposed to require fuel use of both fuels to be logged, instead of either fuel.

New Non-Emergency Electrical Generating Engines

New monitoring procedures are required for the proposed emission standards for new, non-emergency, electrical generating engines. All such engines will be required to monitor: the net electrical output (MWe-hours) of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator and heat recovery equipment; and the useful heat recovered (MWth-hours), which is the thermal energy recovered and put to an actual useful purpose.

Emissions in pounds per MWe-hour must be calculated based on CEMS data, source tests, and weekly emission checks. Mass emissions will be calculated using an F factor method from EPA 40 CFR 60, Appendix A, Method 19, or other approved method. Because Method 19 does not directly address VOC and CO, necessary conversion factors are provided in the rule. An annual report is required to verify compliance with the annual EEF.

Portable Analyzer Training

In order to assure that persons conducting the portable analyzer testing are properly trained to understand the equipment and the procedures for conducting testing, maintenance and calibration, subparagraph (f)(1)(G) requires persons to take a District-approved training program and obtain a certification issued by the District. SCAQMD intends to conduct the training.

Reporting noncompliance to the Executive Officer

If an engine owner/operator finds an engine to be operating outside the acceptable range for control equipment parameters, engine operating parameters, engine exhaust NOx, CO, VOC or oxygen concentrations, the owner/operator will: report the noncompliance within one hour in the same manner required by paragraph (b)(1) of Rule 430 – Breakdowns; immediately correct the noncompliance or shut down the engine within 24 hours or the end of an operating cycle, in the same manner as required by subparagraph (b)(3)(iv) of Rule 430; and comply with all requirements of Rule 430 if there was a breakdown.

Within seven calendar days after reported noncompliance has been corrected, but no later than thirty days from initial noncompliance date, operators will be required to submit a written noncompliance report which includes:

- Identification of equipment
- Duration of noncompliance
- Date of correction and information demonstrating compliance was achieved
- Types of excess emissions
- Quantification of excess emissions
- Determination of noncompliance as a result of operator error, neglect or improper operation or maintenance
- Verification that steps were immediately taken to correct noncompliance
- Description of corrective measures undertaken and/or to be undertaken to avoid similar noncompliance
- Photos or images of equipment which failed, if available

The rule provides a 72 hour window in which to report any engine or control system parameter which goes out of the acceptable range established by the Inspection and Monitoring plan or permit condition. In case of emergencies that prevent reporting all required information within the 72 hour limit, an allowance may be granted to extend the time of reporting.

Exemptions

Emergency, Flood Control and Fire Fighting Engines

The current rule exempts several types of engines from the subdivision (d) emission limits. Paragraph (h)(2) exempts emergency engines while paragraph (h)(3) exempts fire fighting and flood control engines. The proposed amendments do the following: combine the exemptions into paragraph (h)(2); require all of these engines to operate less than 200 hours per year; and require that permits conditions specifically limit the annual operating hours. This exemption also applies to agricultural emergency standby engines that are exempt from permit and operate 200 hours or less per year.

Start up Exemption

The current rule has no exemption during engine startups, after an engine overhaul or major repair requiring removal of a cylinder head or initial commissioning of new engine. The proposed amendments in paragraphs (h)(10),(11) and (12) will provide an exemption from:

- Startups for complying with the emission limits in the rule until emission controls reach operating temperature, but not longer than 30 minutes. AQMD may approve a longer period and make it a condition of the permit to operate;
- After an engine overhaul or major repair for a period not to exceed four operating hours;
- Initial commissioning of new engine for a period specified by permit conditions up to a maximum of 150 operating hours.

CONTROL TECHNOLOGIES

Although Rule 1110.2 controls emissions from both liquid-fueled (e.g., gasoline and diesel) and gaseous-fueled (e.g., natural gas, biogas, etc.) ICEs, the majority of engines expected to be affected by PAR 1110.2 are gaseous-fueled ICEs. Control technologies that are anticipated to be used to comply with PAR 1110.2 are described relative to the gaseous fuel used by the ICE. For the purposes of this discussion and the analysis in Chapter 4, the two primary fuel types under consideration are non-biogas and biogas. Non-biogas refers to natural gas, which is a gaseous fossil fuel consisting primarily of methane, but also includes significant quantities of ethane, butane, propane, carbon dioxide, nitrogen, helium and hydrogen sulfide. Biogas typically refers to a (biofuel) gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and carbon dioxide. In most cases, biogas from landfills and sewage treatment contains siloxanes. The following subsections summarize the various types of control technologies expected to be used to comply with PAR 1110.2, divided into the two main categories of non-biogas and biogas engines.

Non-Biogas Engines – Retrofit Technologies

To comply with PAR 1110.2 the following control technologies are expected to be used by operators of non-biogas engines: oxidation catalyst, selective catalytic reduction or improved non-selective catalytic reduction. These control technologies are summarized in the following subsections.

Oxidation Catalyst

To meet the compliance limits of PAR 1110.2, SCAQMD staff expects that operators of non-biogas, RECLAIM, lean-burn engines that were not subject to BACT to install oxidation catalysts. Oxidation catalysts have two simultaneous tasks: 1) oxidation of carbon monoxide to carbon dioxide ($2CO + O2 \rightarrow 2CO2$) and 2) oxidation of unburned hydrocarbons (unburned and partially-burned fuel) to carbon dioxide and water ($2CxHy + (2x+y/2)O2 \rightarrow 2xCO2 + yH2O$). An oxidation catalyst contains materials (generally precious metals such as platinum or palladium) that promote oxidation reactions between oxygen, CO, and VOC to produce carbon dioxide and water vapor. These reactions occur when exhaust at the proper temperature and containing sufficient oxygen passes through the catalyst. Depending on the catalyst formulation, an oxidation catalyst may obtain reductions at temperatures as low as 300 or 400^{o}F, although minimum temperatures in the 600 to 700^{o}F range are generally required to achieve maximum reductions. The catalyst will maintain adequate performance at temperatures typically as high as 1350°F before problems with physical degradation of the catalyst occur. In the case of rich-burn engines, where the exhaust does not contain enough oxygen to fully oxidize the CO and VOC in the exhaust, air can be injected into the exhaust upstream of the catalyst.

This type of catalytic converter is widely used on lean-burn engines to reduce hydrocarbon and carbon monoxide emissions.

The oxidation catalyst is a corrugated base metal substrate with an alumina wash coat loaded with precious metals such as platinum. The alumina is porous allowing for large surface areas to promote oxidation of any unreacted CO and hydrocarbons with oxygen remaining in the exhaust gas. Most oxidation catalysts can be retrofitted onto the engine without disruption of the existing design configuration.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion control equipment that is considered to be BACT for new equipment and BARCT for existing equipment. SCR can be used, if cost-effective, for NOx control of combustion sources like engines, boilers, process heaters, and gas turbines and it is capable of reducing NOx emissions by as much as 90 percent or higher. A typical SCR system design consists of an ammonia or urea reductant storage tank, ammonia vaporization and injection equipment, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of reductant and air into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor with catalyst, the catalyst, reductant, and oxygen in the flue gas exhaust react primarily (i.e., selectively) with NO and NO2 to form nitrogen and water. The amount of reductant introduced into the SCR system is approximately a one-to-one molar ratio of reductant to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalyst structures: the first type is one in which the catalyst is coated onto a metal structure and the second type is one with a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two forms: 1) solid, block configurations or 2) modules, plate or honeycomb type. Catalysts are comprised of a base material of titanium dioxide (TiO2) that is coated with either tungsten trioxide (WO3), molybdic anhydride (MoO3), vanadium pentoxide (V2O5), or iron oxide (Fe2O3). These materials are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 degrees Fahrenheit (°F) and the maximum operating temperature for the catalyst is 800 °F. Zeolite SCR catalysts have a higher temperature operating range. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between

550°F and 750°F to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns associated with SCRs is the oxidation of sulfur dioxide (SO2) in the exhaust gas to sulfur trioxide (SO3) and the subsequent reaction between SO3 and ammonia to form secondary particulates such as ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance. The production of secondary particulates can be substantially minimized by reducing the quantity of injected ammonia, maintaining the exhaust temperature within a predetermined range, and maintaining a precise NOx to ammonia molar ratio to minimize the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip is typically zero to five ppm.

Lean-burn engines can use SCR to control NOx. All lean-burn, non-biogas engines are controlled with the exception of RECLAIM engines, which are exempt from the NOx limited Rule 1110.2.

Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) is another post-combustion control technique used to reduce the quantity of NOx in the flue gas by injecting ammonia or urea. The main differences between SNCR and SCR is that the SNCR reaction between ammonia and NOx in the hot flue gas occurs without the need for a catalyst and at much higher temperatures (i.e., between 1,200°F to 2,000°F). The SNCR reaction is also affected by the short residence time of ammonia and the molar ratio between ammonia and the initial quantities of NOx such that small quantities of unreacted ammonia remains (i.e., ammonia slip) and is subsequently released in the flue gas. With a control efficiency ranging between 50 and 85 percent, SNCR does not achieve as great of NOx emission reductions as SCR. Therefore, SNCR would not be considered equivalent to BARCT unless combined with other NOx control technologies.

Three-way Catalyst

Three-way catalysts reduce NOx in addition to oxidizing carbon monoxide and unburned hydrocarbons. The oxidation process is described above under the subheading oxidation catalysts. Reduction of NOx emissions requires an additional step. Platinum catalysis can be used to reduce NOx emissions. The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The three-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric. An electronic controller, which includes an oxygen sensor and feedback mechanism, is often necessary to maintain the air/fuel ratio in this narrow band. At this air/fuel ratio, the oxygen concentration in the exhaust is low, while concentrations of VOC and CO are not excessive.

The core, or substrate in modern catalytic converters is most often a ceramic honeycomb, however stainless steel foil honeycombs are also used. The purpose of the core is to "support the catalyst" and therefore it is often called a "catalyst support". In an effort to make converters more efficient, a washcoat is utilized, most often a mixture of silica and alumina. The washcoat, when added to the core, forms a rough, irregular surface which has a far greater surface area than the flat core surfaces, which is desirable to give the converter core a larger surface area and, therefore, more places for active precious metal sites. The catalyst is added to the washcoat (in suspension) before application to the core. The catalyst itself is most often a precious metal. Platinum is the most active catalyst and is widely used. However, it is not suitable for all applications because of unwanted additional reactions and/or cost. Palladium and rhodium are two other precious metals that are used. Platinum and rhodium are used as a reduction catalyst, while platinum and palladium are used as an oxidization catalyst.

Non-Biogas Engines – Replacement Technologies

The cost of compliance (CEMS, I&M, add-on control technology, etc.) may make it less costly to remove the existing non-biogas ICEs and replace them with other technologies, primarily electric motors. Replacing ICEs with electric motors means they would no longer be subject to the requirements of PAR 1110.2. The follow briefly describes electric motors used as a non-biogas replacement technology.

Electric Motors

An electric motor converts electrical energy into mechanical energy. Most electric motors work by electromagnetism, but motors based on other electromechanical phenomena, such as electrostatic forces and the piezoelectric effect, also exist. The fundamental principle upon which electromagnetic motors are based is that there is a mechanical force on any current-carrying wire contained within a magnetic field. The force is described by the Lorentz force law and is perpendicular to both the wire and the magnetic field. Most magnetic motors are rotary, but linear motors also exist. In a rotary motor, the rotating part (usually on the inside) is called the rotor, and the stationary part is called the stator. The rotor rotates because the wires and magnetic field are arranged so that a torque is developed about the rotor's axis. The motor contains electromagnets that are wound on a frame. Though this frame is often called the armature, the term is often erroneously applied. Correctly, the armature is that part of the motor across which the input voltage is supplied. Depending upon the design of the machine, either the rotor or the stator can serve as the armature.

For some operators, removing the existing ICEs driving pumps or compressors and replacing them electric motors may less costly when compared to the cost of complying with PAR 1110.2, which may include the costs of installing CEMS, inspection and maintenance, installing add-on control technology, etc. For the same reason, operators of ICE electrical generators may choose to simply shut the ICE down and buy electricity from the grid to operate the motors. Operators who choose this option, however, may also need to install an emergency backup generator. In the analysis of impacts in Chapter 4 SCAQMD staff assumed that 40 percent of the affected facility operators would use their existing ICEs for emergency backup generators and 20 percent were assumed to use diesel-fueled emergency generators. The remaining 40 percent are not expected to need emergency generators. It is expected that this assumption is an over estimation since some facility operators would not require emergency generators.

Biogas Engines – Retrofit Technologies

Emissions control of biogas engines typically requires biogas pre-treatment systems (BPTS) to remove siloxanes that would inactivate the catalysts. Biogas engines are expected to use a biogas pre-treatment system (BPTS) with SCR and oxidation catalyst (see the description SCR and oxidation catalysts in the subsections under "Non-biogas Engines), or use technologies that do not require BPTS, such as NOxTech or the CL.AIR® system. The following subsections briefly describe the NOxTech and CL.AIR® emissions control technologies for biogas engines.

Biogas Pre-Treatment Systems (BPTS)

BPTSs are designed to remove siloxanes from biogas streams to prevent fouling of emissions control systems. Typically the system consists of a condenser followed by a vessel or vessels segmented with different layers of carbon or silica gel media. Each medium is designed to filter siloxane, H_2S and VOCs, respectively. The change-out time for the vessel or vessels is approximately every 60 to 90 days. Inlet and outlet samples are taken at specific intervals to determine vessel condition. Tests have indicated that the control efficiency of BPTS produces non-detect levels of siloxanes, i.e., in the 100 ppb range.

NOx Tech Emissions Control for Biogas

NOxTech is an emissions control system for diesel and biogas engines. Emissions of hydrocarbons, CO, soot, and NOx are reduced in a one-step process. Engine exhaust is preheated in annular heat exchange tubes in the NOxTech reactor. In the reaction chamber, injected fuel auto ignites in the preheated exhaust and self-sustains autocatalysis based on engine load and, with the injection of urea or ammonia, reduces NOx. NOxTech controls emissions auto catalytically by gas-phase reactions. The gas-phase autocatalysis is self-sustained by auto thermal combustion, so NOxTech is not affected by contaminants which poison, foul, and plug catalysts. Feedback from a NOx analyzer can trim chemical injection in combination with the feed forward control.

When temperature in the reaction chamber is controlled in the range of 1,400-1,550°F, criteria pollutants, including ammonia slip, are maintained to specified limits. Biogas is a suitable fuel for auto thermal combustion and NOxTech equipment limits the additional biogas consumption within five to 10 percent of the engine fuel rate. Heat recovery minimizes this fuel penalty.

CL.Air Exhaust Treatment System

The CL.Air® system is designed for the post-combustion treatment of engine exhaust pollutants. The system is based on a regenerative heat exchanger and consists of two thermal storage media, a reaction chamber and a switching unit. The exhaust gas flows from the engine at a temperature of approximately 986°F via the switching unit into the first medium, where it is heated to approximately 1,472°F. For startup, the entering flue gas is heated by electrical heating elements. In the reaction chamber, the exhaust gas reacts with the oxygen it contains, oxidizing carbon monoxide and HC to produce carbon dioxide and water.

The exhaust gas emits heat again as it passes through the second medium and at a temperature of 1,022°F to 1,058°F it reaches the switching unit, which directs it to the smokestack or a downstream waste heat boiler. After a flow period of two to three minutes the direction of flow is reversed, and the exhaust gas takes heat away from storage medium two and passes it on to storage medium one. In this manner, the energy requirement of the thermal reactor is minimized (i.e., no additional heating is required). The CL.Air® system is not typically subject to the fouling problems catalytic emission control systems would have.

Biogas Engines – Replacement Technologies

The cost of compliance (CEMS, I&M, add-on control technology, etc.) may make it less costly to remove the existing biogas ICEs and replace them with other technologies. These technologies include boilers, gas turbines, microturbines, fuel cells and biogas-to-LNG systems. Replacing ICEs with the technologies described below means they would no longer be subject to the requirements of PAR 1110.2, but may be subject to other source-specific rules or regulations such as Regulation XIII – New Source Review. The follow is a description of each replacement technology.

Boilers

Boilers are steel or cast-iron pressure vessels designed to transfer heat from the combustion of a fuel to water contained in the vessel to produce hot water or steam. The principle components of a boiler are a burner, a firebox, heat exchanger and a means of creating and directing gas flow though the unit. Landfill gas-fired boilers in the district produce steam that drive electrical generators.

Gas Turbines

Gas turbines convert energy stored in a fluid into mechanical energy by channeling the fluid through a system of stationary and moving vanes. The moving vanes are attached to a rotor to turn either a shaft, producing work output in the form of torque, or to generate velocity and pressure energy in a jet. Gas turbines can be used in combined-cycle cogeneration and simple-cycle arrangements. Combined cycle systems are typically used for very large systems and generally have higher capital costs than simple cycle gas turbines. Although combined cycle systems are more efficient, thus, generating lower emissions, to be conservative the analysis of impacts in Chapter 4 assumed that simple-cycle systems, not combined cycle systems, would be a possible replacement for existing biogas engines in response to PAR 1110.2.

The CEC states that gas turbines generate relatively low amounts of NOx and CO and are fairly efficient when compared to ICEs. The most common turbines at landfills in California are Solar Turbines rated from one to five megawatts. The benefits of installing gas turbines are their lower maintenance and lower emissions, but they require more up front capital costs.

Microturbines

Microturbines are small combustion turbines and are composed of a compressor, a combustor, a recuperator (some models), a turbine, a generator and an alternator. According to the CEC, microturbines are available in sizes between 30 and 150 kilowatts. The advantage of microturbines is their non-labor-intensive operation, although gas treatment systems with biogas are needed. Microturbines have reached commercial status at several biogas facilities in the district.

Fuel Cells

Fuel cells use an electrochemical process that uses a catalyst to react hydrogen and oxygen, which produces direct current (DC) electricity, heat, CO2 and water. According to the CEC, the two commercially available fuel cells for biogas application are molten carbonate fuel cells (MCFCs) and phosphoric acid fuel cells (PAFCs). Fuel cells consist of a fuel reformer to produce hydrogen from methane in biogas, fuel cell stack and inverter. Fuel cells generate negligible criteria pollutant emissions.

A BPTS is required to remove contaminants from biogas that would foul catalysts in the fuel reformer and stack. Fuel cells have high gas to energy conversion efficiencies, but have high capital cost. Since fuel cells generate negligible direct and indirect emissions, adverse environmental impacts were not analyzed further in this EA.

Biogas-to-Liquefied Natural Gas (LNG) Systems

Biogas-to-LNG systems convert biogas to LNG and CO2. LNG is created when natural gas is cooled to minus 260ºF, reducing six-hundred cubic feet of gas into one cubic foot of liquid methane. This process consists of several stages of compression and cooling. LNG plants would consist of a power generation building, programmable logic control/motor control center building, compress skids, refrigeration skids, liquefier skids, storage tanks and loading equipment. The plant is composed of vessels, compressors, pipes, valves, filters, coolers instruments and process components in six modules: purification, CO2 removal, refrigeration, liquefaction and post purification, instrument air, and controls. An LNG storage and dispensing system is needed to transfer LNG from the facility to trucks.

The LNG facility at the Frank R. Bowerman Landfill in Irvine, California was used as a basis for the analysis in this report.[10] The Bowerman facility uses ICEs to supply power to the LNG facility. Since LNG systems are assumed to replace existing ICEs at affected facilities, it was assumed that facility operators who choose to install LNG plants in place of existing ICEs would use electricity from the power grid. Since the LNG facility would require some energy in the form of heat, it was assumed that operators that replace existing ICEs at affected facilities would install boilers to generate heat for the facility.

[10] Prometheus Energy Company, Bowerman I Natural Gas Process Facility Project Description, prepared for SCAQMD, undated.

The Bowerman facility has a LNG storage tank that can store five days worth of LNG generated at the facility. Dr. John Barclay of Prometheus Energy has stated that typical design of LNG storage tanks includes a capacity of three days.[11]

[11] Phone conversation between Dr. John Barclay, Chief Technology Officer of Prometheus Energy Company and James Koizumi of SCAQMD, August 1, 2007.

CHAPTER 3

EXISTING SETTING

Introduction
Aesthetics
Air Quality
Hazards/Hazardous Material
Solid/Hazardous Waste

INTRODUCTION

In order to determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project's impacts against the backdrop of the environment as it exists at the time the notice of preparation is published. The CEQA Guidelines 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" (CEQA Guidelines §15360; see also Public Resources Code §21060.5). Furthermore, a CEQA document must include a description of the physical environment in the vicinity of the project, as it exists at the time the notice of preparation is published, from both a local and regional perspective (CEQA Guidelines §15125). Therefore, the "environment" or "existing setting" against which a project's impacts are compared consists of the immediate, contemporaneous physical conditions at and around the project site (Remy, et al; 1996).

AESTHEICS

General Affected Facilities

ICEs are used for commercial and industrial applications. ICEs can be housed within buildings or placed outside. If placed within a building, the ICEs will have ducting to the outside of the building. Building and fire codes regulate the placement and height of the exhaust stack.

If placed outside ICEs may be placed within housing that protects the ICEs from weather and reduces noise or may be exposed to the elements. The majority of the ICE and related equipment with the exception of ducting is low in height and not visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities may buffer the view of such equipment.

Biogas Facilities

Digester Gas

Digester gas facilities are placed industrial areas and are typically visibly industrial. Storage tanks and piping may be visible from outside the property line. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

Landfill Gas

Active landfills are placed in industrial areas and are typically visibly industrial. Earthmoving equipment, heavy duty diesel transfer and disposal trucks may be seen from outside the property line. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

AIR QUALITY

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, carbon monoxide (CO), nitrogen dioxide (NO2), particulate matter less than 10 microns (PM10), particulate matter less than 2.5 microns (PM2.5) sulfur dioxide (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 sulfate, visibility, 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 3-1. The SCAQMD monitors levels of various criteria pollutants at 34 monitoring stations. The 2004 air quality data from SCAQMD's monitoring stations are presented in Table 3-2.

Table 3-1
State and Federal Ambient Air Quality Standards

AIR POLLUTANT	STATE STANDARD Concentration/ Averaging Time	FEDERAL PRIMARY STANDARD Concentration/ Averaging Time (>)	MOST RELEVANT EFFECTS
Ozone	0.09 ppm, 1-hour average > 0.07 ppm, 8-hr avg.>	0.08 ppm, 8-hour average	(a) Pulmonary function decrements and localized lung edema in humans and animals; (b) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (c) Increased mortality risk; (d) 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; (e) Vegetation damage; (f) Property damage
Carbon Monoxide	9.0 ppm, 8-hour average> 20 ppm, 1-hour average>	9 ppm, 8-hour average 35 ppm, 1-hour average	(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; (d) Possible increased risk to fetuses
Nitrogen Dioxide	0.18 ppm, 1-hour average> 0.030 ppm, annual average>	0.053 ppm, annual average	(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; (c) Contribution to atmospheric discoloration

Table 3-1 (Concluded)
State and Federal Ambient Air Quality Standards

AIR POLLUTANT	STATE STANDARD Concentration/ Averaging Time	FEDERAL PRIMARY STANDARD Concentration/ Averaging Time (>)	MOST RELEVANT EFFECTS
Sulfur Dioxide	0.04 ppm, 24-hour average> 0.25 ppm, 1-hour average>	0.03 ppm, annual average 0.14 ppm, 24-hour average	(a) Bronchoconstriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in person with asthma
Suspended Particulate Matter (PM10)	20 $\mu g/m^3$, annual arithmetic mean > 50 $\mu g/m^3$, 24-hour average>	150 $\mu g/m^3$, 24-hour average	(a) Exacerbation of symptoms in sensitive patients with respiratory or cardiovascular disease; (b) Declines in pulmonary function growth in children; (c) Increased risk of premature death from heart or lung diseases in the elderly
Suspended Particulate Matter (PM2.5)	12 μg/m3, ann. arithmetic mean >	15 $\mu g/m^3$, annual arithmetic mean 35 $\mu g/m^3$, 24-hour average(1)	
Sulfates	25 $\mu g/m^3$, 24-hour average>=	--(2)	(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; (f) Property damage
Lead	1.5 $\mu g/m^3$, 30-day average>=	1.5 $\mu g/m^3$, calendar quarter	(a) Increased body burden; (b) Impairment of blood formation and nerve conduction
Visibility-Reducing Particles	In sufficient amount to give an extinction coefficient >0.23 km^{-1} (visual range less than 10 miles), with relative humidity <70%, 8-hour average (10am – 6pm, PST)	--(2)	Visibility impairment on days when relative humidity is less than 70 percent

ppm = parts per million

(1) The U.S. EPA lowered the PM2.5 24-hour average standard from 65$\mu g/m^3$ to 35$\mu g/m^3$ in September 2006. The 65$\mu g/m^3$ standard will be in effect until 2010.

(2) No federal standard established.

Table 3-2
2006 Air Quality Data – South Coast Air Quality Management District

CARBON MONOXIDE (CO)						
					No. Days Standard Exceeded[a]	
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hour)	Max. Conc. (ppm, 8-hour)	Federal ≥ 9.5 ppm, 8-hour	State > 9.0 ppm, 8-hour
LOS ANGELES COUNTY (Co)						
1	Central Los Angeles	362	3	2.6	0	0
2	Northwest Coast Los Angeles Co	365	3	2.0	0	0
3	Southwest Coast Los Angeles Co	363	3	2.3	0	0
4	South Coastal Los Angeles Co1	360	4	3.4	0	0
4	South Coastal Los Angeles Co2	--	--	--	--	--
6	West San Fernando Valley	365	5	3.4	0	0
7	East San Fernando Valley	365	4	3.5	0	0
8	West San Gabriel Valley	360	4	2.8	0	0
9	East San Gabriel Valley 1	365	2	1.7	0	0
9	East San Gabriel Valley 2	363	2	2.0	0	0
10	Pomona/Walnut Valley	365	3	2.1	0	0
11	South San Gabriel Valley	232*	3*	2.7*	0*	0*
12	South Central LA County	365	8	6.4	0	0
13	Santa Clarita Valley	363	2	1.3	0	0
ORANGE COUNTY						
16	North Orange County	362	6	3.0	0	0
17	Central Orange County	365	5	3.0	0	0
18	North Coastal Orange County	365	4	3.0	0	0
19	Saddleback Valley	365	2	1.8	0	0
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	365	3	2.1	0	0
23	Metropolitan Riverside County 2	365	4	2.3	0	0
23	Mira Loma	364	4	2.7	0	0
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	362	1	1.0	0	0
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	365	2	1.0	0	0
30	Coachella Valley 2**	--	--	--	--	--
SAN BERNARDINO COUNTY						
32	NW San Bernardino Valley	360	3	1.8	0	0
33	SW San Bernardino Valley	--	--	--	--	--
34	Central San Bernardino Valley 1	365	3	2.0	0	0
34	Central San Bernardino Valley 2	364	3	2.3	0	0
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		8	6.4	0	0
	SOUTH COAST AIR BASIN		8	6.4	0	0

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- = 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 (35ppm and 20 ppm) were not exceeded, either.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

OZONE (O_3)										
							No. Days Standard Exceeded			
							Federal [b)]		State[c)]	
Source Rec. Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hr)	Max. Conc. (ppm, 8-hr)	Fourth Highest Conc. (ppm, 8-hr)	Health Advisory ≥ 0.15 ppm, 1-hr	> 0.12 ppm, 1-hr	> 0.08 ppm, 8-hr	> 0.09 ppm, 1-hr	> 0.07 ppm, 1-hr
LOS ANGELES (LA) COUNTY (Co)										
1	Central LA	362	0.11	0.079	0.077	0	0	0	8	4
2	NW Coastal LA Co	365	0.10	0.074	0.069	0	0	0	3	0
3	SW Coastal LA Co	360	0.08	0.066	0.062	0	0	0	0	0
4	South Coastal LA Co1	364	0.08	0.058	0.058	0	0	0	0	0
4	South Coastal LA Co2	--	--	--	--	--	--	--	--	--
6	West San Fernando V	361	0.16	0.108	0.105	1	6	17	32	39
7	East San Fernando V	365	0.17	0.128	0.099	2	6	12	25	23
8	W San Gabriel Valley	365	0.15	0.117	0.095	1	5	7	25	24
9	E San Gabriel Valley 1	364	0.17	0.120	0.091	2	7	10	23	19
9	E San Gabriel Valley 2	363	0.18	0.128	0.107	2	10	15	37	31
10	Pomona/Walnut Valley	365	0.15	0.128	0.109	2	9	16	32	30
11	S San Gabriel Valley	250*	0.13*	0.095*	0.080*	0*	1*	3*	9*	5*
12	South Central LA Co	365	0.09	0.066	0.064	0	0	0	0	0
13	Santa Clarita Valley	359	0.16	0.120	0.112	1	20	40	62	64
ORANGE (OR) COUNTY (Co)										
16	North Orange Co	362	0.15	0.114	0.092	1	3	4	8	9
17	Central Orange Co	365	0.11	0.088	0.072	0	0	1	5	3
18	North Coastal OR Co	365	0.07	0.064	0.062	0	0	0	0	0
19	Saddleback Valley	356	0.12	0.105	0.092	0	0	6	13	17
RIVERSIDE (RV) COUNTY (Co)										
22	Norco/Corona	--	--	--	--	--	--	--	--	--
23	Metropolitan RV Co 1	365	0.15	0.116	0.113	1	8	30	45	59
23	Metropolitan RV Co 2	--	--	--	--	--	--	--	--	--
23	Mira Loma	364	0.16	0.119	0.107	1	4	25	39	48
24	Perris Valley	351	0.17	0.122	0.114	3	12	53	76	84
25	Lake Elsinore	362	0.14	0.109	0.102	0	3	24	40	58
29	Banning Airport	357	0.14	0.115	0.104	0	8	44	57	78
30	Coachella Valley 1**	361	0.13	0.109	0.101	0	2	23	37	67
30	Coachella Valley 2**	364	0.10	0.089	0.087	0	0	7	4	29
SAN BERNARDINO (SB) COUNTY										
32	Northwest SB Valley	365	0.17	0.130	0.114	2	14	25	50	54
33	Southwest SB Valley	--	--	--	--	--	--	--	--	--
34	Central SB Valley 1	361	0.16	0.123	0.116	1	12	29	47	49
34	Central SB Valley 2	362	0.15	0.127	0.119	3	10	29	52	57
35	East SB Valley	365	0.16	0.135	0.125	5	11	36	60	64
37	Central SB Mountains	365	0.16	0.142	0.112	2	9	59	71	96
38	East SB Mountains	--	--	--	--	--	--	--	--	--
DISTRICT MAXIMUM			0.18	0.142	0.125	5	20	59	76	96
SOUTH COAST AIR BASIN			0.18	0.142	0.125	10	35	86	102	121

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- - Pollutant not monitored	** Salton Sea Air Basin

b) The federal 1-hour ozone standard was revoked and replaced by the 8-hour average ozone standard effective June 15, 2005. The 8-hour average California ozone standard of 0.07 ppm was established effective May 17, 2006.

c) The state standard is 1-hour average NO_2 > 0.25 ppm. The federal standard is annual arithmetic mean NO_2 > 0.0534 ppm. Air Resources Board has approved to lower the NO_2 1-hour standard to 0.18 ppm and establish a new annual standard of 0.030 ppm. The revisions are expected to become effective later in 2007.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

NITROGEN DIOXIDE (NO_2)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hour[d])	Annual Average[d] AAM Conc. (ppm)
LOS ANGELES COUNTY				
1	Central Los Angeles	360	0.11	0.0288
2	Northwest Coastal Los Angeles Co	365	0.08	0.0173
3	Southwest Coastal Los Angeles Co	351	0.10	0.0155
4	South Coastal Los Angeles Co1	357	0.10	0.0215
4	South Coastal Los Angeles Co2	--	--	--
6	West San Fernando Valley	363	0.07	0.0174
7	East San Fernando Valley	365	0.10	0.0274
8	West San Gabriel Valley	365	0.12	0.0245
9	East San Gabriel Valley 1	365	0.11	0.0258
9	East San Gabriel Valley 2	362	0.10	0.0206
10	Pomona/Walnut Valley	365	0.10	0.0307
11	South San Gabriel Valley	204*	0.10*	0.0283*
12	South Central LA County	363	0.14	0.0306
13	Santa Clarita Valley	359	0.08	0.0184
ORANGE COUNTY				
16	North Orange County	361	0.09	0.0224
17	Central Orange County	343	0.11	0.0197
18	North Coastal Orange County	361	0.10	0.0145
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	365	0.08	0.0199
23	Metropolitan Riverside County 2	--	--	--
23	Mira Loma	332	0.08	0.0194
24	Perris Valley	--	--	--
25	Lake Elsinore	352	0.07	0.0151
29	Banning Airport	355	0.11	0.0161
30	Coachella Valley 1**	359	0.09	0.0103
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest SB Valley	337	0.10	0.0310
33	Southwest SB Valley	--	--	--
34	Central SB Valley 1	362	0.09	0.0270
34	Central SB Valley 2	362	0.09	0.0252
35	East SB Valley	--	--	--
37	Central SB Mountains	--	--	--
38	East SB Mountains	--	--	--
	DISTRICT MAXIMUM		0.14	0.0310
	SOUTH COAST AIR BASIN		0.14	0.0310

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin
-- = Pollutant not monitored	

d) The state standards are 1-hour average SO_2 > 0.25 ppm and 24-hour average SO_2 > 0.04 ppm. The federal standards are annual arithmetic mean SO_2 > 0.03 ppm, 24-hour average > 0.14 ppm, and 3-hour average > 0.50 ppm. The federal and state SO_2 standards were not exceeded.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SULFUR DIOXIDE (SO_2)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Concentration[e)]	
			(ppm, 1-hour)	(ppm, 24-hour)
LOS ANGELES COUNTY				
1	Central Los Angeles	365	0.03	0.006
2	Northwest Coast Los Angeles County	--	--	--
3	Southwest Coast Los Angeles County	363	0.02	0.006
4	South Coastal Los Angeles County 1	364	0.03	0.010
4	South Coastal Los Angeles County 2	--	--	--
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	360	0.01	0.004
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 LA County	--	--	--
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
18	North Coastal Orange County	353	0.01	0.004
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	365	0.01	0.004
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**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	--	--	--
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	365	0.01	0.003
34	Central San Bernardino Valley 2	--	--	--
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
	DISTRICT MAXIMUM		0.03	0.010
	SOUTH COAST AIR BASIN		0.03	0.010

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- = Pollutant not monitored	** Salton Sea Air Basin

e) PM10 samples were collected every 6 days at all sites except for Station Number 4144 and 4157 where samples were collected every 3 days.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM10 f),						
				No. (%) Samples Exceeding Standard		
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m^3, 24-hour)	Federal > 150 µg/m^3, 24-hour	State > 50 µg/m^3, 24-hour	Annual Average i) AAM Conc. (µg/m^3)
LOS ANGELES COUNTY (Co)						
1	Central Los Angeles	59	59	0	3(5.1)	30.3
2	NW Coastal Los Angeles County	--	--	--	--	--
3	SW Coast Los Angeles County2	51	45	0	0	26.5
4	South Coastal Los Angeles County1	61	78	0	6(9.8)	31.1
4	South Coastal Los Angeles County2	58	117	0	19(32.7)	45.0
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	54	71	0	10(18.5)	35.6
8	West San Fernando Valley	--	--	--	--	--
9	East San Gabriel Valley 1	58	81	0	7(12.1)	31.9
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central LA County	--	--	--	--	--
13	Santa Clarita Valley	58	53	0	1(1.7)	23.4
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	56	104	0	7(12.5)	33.4
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	50	57	0	1(2.0)	22.8
RIVERSIDE COUNTY						
22	Norco/Corona	57	74	0	10(17.5)	36.5
23	Metropolitan Riverside County 1	118	109	0	71(60.2)	54.4
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	124	0	41(69.5)	64.0
24	Perris Valley	54	125	0	19(35.2)	45.0
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	55	75	0	8(14.6)	31.1
30	Coachella Valley 1**	57	73+	0+	2(3.5)+	24.5+
30	Coachella Valley 2**	115	122+	0+	57(49.6)+	52.7+
SAN BERNARDINO COUNTY-						
32	NW San Bernardino Valley	--	--	--	--	--
33	SW San Bernardino Valley	62	78	0	17(27.4)	42.3
34	Central San Bernardino Valley 1	60	142	0	31(51.7)	53.5
34	Central San Bernardino Valley 2	57	92	0	24(42.1)	46.0
35	East San Bernardino Valley	60	103	0	12(20.0)	36.2
37	Central San Bernardino Mountains	58	63	0	1(1.7)	26.2
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		142+	0+	71	64.0
	SOUTH COAST AIR BASIN		142+	0+	75	64.0

KEY:

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

f) PM2.5 samples were collected every 3 days at all sites except for the following sites: Station Numbers 060, 072, 077, 087, 3176, and 4144 where samples were taken every day, and Station Number 5818 where samples were taken every 6 days.

i) U.S. EPA has revised the federal 24-hour PM2.5 standard from 65 µg/m^3 to 35 µg/m^3; effective December 17, 2006.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM2.5 g)						
					No. (%) Samples Exceeding Standard	Annual Averages j)
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m³, 24-hour)	98th Percentile Conc. in µg/m3 24-hr	Federal > 65 µg/m³, 24-hour	AAM Conc. (µg/m³)
LOS ANGELES COUNTY						
1	Central Los Angeles	330	56.2	38.9	0	15.6
2	Northwest Coastal Los Angeles Co	--	--	--	--	--
3	Southwest Coastal Los Angeles Co 2	--	--	--	--	--
4	South Coastal Los Angeles Co 1	290*	58.5*	34.9*	0*	14.2*
4	South Coastal Los Angeles County 2	320	53.6	35.3	0	14.5
6	West San Fernando Valley	92	44.1	32.0	0	12.9
7	East San Fernando Valley	104	50.7	43.4	0	16.6
8	West San Gabriel Valley	113	45.9	32.1	0	13.4
9	East San Gabriel Valley 1	278*	52.8*	38.5*	0*	15.5*
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	116	72.2	43.1	1(0.9)	16.7
12	South Central LA County	107	55.0	44.5	0	16.7
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	330	56.2	40.5	0	14.1
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	106	47.0	25.7	0	11.0
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	300	68.5	53.7	1(0.3)	19.0
23	Metropolitan Riverside County 2	105	55.3	47.7	0	17.0
23	Mira Loma	113	63.0	52.5	0	20.6
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	111	24.8	15.9	0	7.7
30	Coachella Valley 2**	107	24.3	19.1	0	9.5
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	107	53.7	41.5	0	18.5
34	Central San Bernardino Valley1	112	52.6	43.8	0	17.6
34	Central San Bernardino Valley2	102	55.0	48.4	0	17.8
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	42*	40.1*	40.1*	0*	11.2*
	DISTRICT MAXIMUM		72.2	53.7	1	20.6
	SOUTH COAST AIR BASIN		72.2	53.7	1	20.6

KEY:

µg/m³ = micrograms per cubic meter of air	-- = Pollutant not monitored
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin

g) Total suspended particulates, lead, and sulfate were determined from samples collected every 6 days by the high volume sampler method, on glass fiber filter media.

j) Federal PM2.5 standard is annual average (AAM) > 15 µg/m³. State standard is annual average (AAM) > 12 µg/m³.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

TOTAL SUSPENDED PARTICULATES TSP h)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m³, 24-hour)	Annual Average AAM Conc. (µg/m³)
LOS ANGELES COUNTY (Co)				
1	Central Los Angeles	59	109	63.3
2	Northwest Coastal Los Angeles Co	56	76	40.2
3	Southwest Coast Los Angeles Co 2	56	84	43.1
4	South Coastal Los Angeles Co 1	62	157	62.9
4	South Coast Los Angeles Co 2	59	192	71.1
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	--	--	--
8	West San Gabriel Valley	60	123	42.8
9	East San Gabriel Valley 1	59	142	68.4
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	58	768	79.3
12	South Central LA County	58	147	68.4
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	59	169	91.2
23	Metropolitan Riverside County 2	59	131	72.9
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	NW San Bernardino Valley	58	105	54.6
33	SW San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	59	190	101.0
34	Central San Bernardino Valley 2	54	174	87.0
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
	DISTRICT MAXIMUM		768	101.0
	SOUTH COAST AIR BASIN		768	101.0

KEY:

µg/m³ = micrograms per cubic meter of air	-- = Pollutant not monitored
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin

h) Federal annual PM10 standard (AAM > 50 µg/m³) was revoked effective December 17, 2006. State standard is annual average (AAM) > 20 µg/m3.

Table 3-2 (Concluded)
2006 Air Quality Data – South Coast Air Quality Management District

		LEAD[h)]		SULFATES (SOx)[h)]	
Source Receptor Area No.	Location of Air Monitoring Station	Max. Monthly Average Conc[k)] (µg/m^3)	Max. Quarterly Average Conc.[k)] (µg/m^3)	Max. Conc. (µg/m^3, 24-hour)	No. (%) Samples Exceeding State Standard ≥ 25 µg/m^3, 24-hour
LOS ANGELES COUNTY (Co)					
1	Central Los Angeles	0.02	0.01	18.2	0
2	Northwest Coastal Los Angeles Co	--	--	12.2	0
3	Southwest Coastal Los Angeles Co 2	0.01	0.01	13.6	0
4	South Coastal Los Angeles Co 1	0.01	0.01	17.8	0
4	South Coastal Los Angeles Co 2	0.01	0.01	18.8	0
6	West San Fernando Valley	--	--	--	--
7	East San Fernando Valley	--	--	--	--
8	West San Gabriel Valley	--	--	28.7	1(1.7)
9	East San Gabriel Valley 1	--	--	20.8	0
9	East San Gabriel Valley 2	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--
11	South San Gabriel Valley	0.03	0.02	28.6	1(1.7)
12	South Central LA County	0.02	0.02	24.1	0
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	0.01	0.01	10.8	0
23	Metropolitan Riverside County 2	0.01	0.01	9.9	0
23	Mira Loma	--	--	--	--
24	Perris Valley	--	--	--	--
25	Lake Elsinore	--	--	--	--
29	Banning Airport	--	--	--	--
30	Coachella Valley 1**	--	--	--	--
30	Coachella Valley 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	NW San Bernardino Valley	0.01	0.01	9.1	0
33	SW San Bernardino Valley	--	--	--	--
34	Central San Bernardino Valley 1	--	--	10.3	0
34	Central San Bernardino Valley 2	0.02	0.01	11.0	0
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM		0.03	0.02	28.7	1
SOUTH COAST AIR BASIN		0.03	0.02	28.7	1

KEY:

µg/m^3 = micrograms per cubic meter of airF	** Salton Sea Air Basin
-- = Pollutant not monitored	

h) Federal annual PM10 standard (AAM > 50 µg/m^3) was revoked effective December 17, 2006. State standard is annual average (AAM) > 20 µg/m3.

k) Federal lead standard is quarterly average > 1.5 µg/m3; and state standard is monthly average > µg/m3. No location exceeded lead standards.

Criteria Pollutants

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. In 2002, 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 25 locations in the Basin and neighboring SSAB areas in 2006. Carbon monoxide concentrations did not exceed the standards in 2006. The highest eight-hour average carbon monoxide concentration recorded (6.4 ppm in the South Central Los Angeles County area) was 71 percent of the federal carbon monoxide standard. The maximum annual average nitrogen dioxide concentration (0.0310 ppm recorded in the Northwest San Bernardino Valley area) was 58 percent of the federal standard. Concentrations of the remaining pollutants remained well below the federal standards.

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 Registrar 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 Registrar 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 (0.03-0.05 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 2006, the SCAQMD regularly monitored ozone concentrations at 29 locations in the Basin and SSAB. All areas monitored were below the stage 1 episode level (0.20 ppm), but the maximum concentrations in the Basin exceeded 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 2006, the maximum ozone, PM10 and PM2.5 concentrations in the Basin continued to exceed federal standards by wide margins. Maximum one-hour and eight-hour average ozone concentrations were 0.18 ppm and 0.142 ppm (the one-hour was recorded in East San Gabriel Valley and the eight-hour was recorded in Central San Bernardino Mountains area). The eight-hour standard was 178 percent of the federal standards. The federal one-hour standard was revoked and replaced by the eight hour standard on June 15, 2005. Maximum 24-hour average and annual average PM10 concentrations were 142 $\mu g/m^3$ recorded in the South Coastal San Bernardino Valley area and 64.0 $\mu g/m^3$ recorded in the Mira Loma area. The 24-hour standard was 94 percent of the federal 24-hour. The federal annual average standards were revoked December 17, 2006. Maximum 24-hour average and annual average PM2.5 concentrations (72.2 $\mu g/m^3$ recorded in the South Central Los Angeles County area and 20.6 $\mu g/m^3$ recorded in the Mira Loma area) were 206 and 137 percent of the federal 24-hour (65 $\mu g/m^3$) and annual average standards, respectively.

In 1997, the USEPA promulgated a new 8-hour national ambient air quality standard for ozone. Soon thereafter, a court decision ordered that the USEPA could not enforce the new standard until adequate justification for the new standard was provided. The USEPA appealed the decision to the Supreme Court. On February 27, 2001, the Supreme Court upheld USEPA's authority and methods to establish clean air standards. The Supreme Court, however, ordered USEPA to revise its implementation plan for the new ozone standard. The EPA has since adopted the new 8-hour standard. Meanwhile, the California Air Resources Board (CARB) and local air districts continue to collect technical information in order to prepare for an eventual State Implementation Plan (SIP) to reduce unhealthful levels of ozone in areas violating the new federal standard. California has previously developed a SIP for the one-hour ozone standard, which has been approved by USEPA for the South Coast Air Basin.

The objective of the 2007 AQMP is to attain and maintain ambient air quality standards. Based upon the modeling analysis described in the Draft Program Environmental Impact Report for the 2007 AQMP implementation of all control measures contained in the 2007 AQMP is anticipated to bring the district into compliance with the federal eight-hour ozone standard by 2024 and the state eight-hour ozone standard beyond 2024.

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 NO_2 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 NO_2 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 2006, nitrogen dioxide concentrations were monitored at 24 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 U.S. county. The nitrogen dioxide state standard was not exceeded at any SCAQMD monitoring location in 2006. The highest one-hour average concentration recorded (0.14 ppm in South Central Los Angeles) was 56 percent of the state 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 2006 at any of the seven SCAQMD locations monitored. Though sulfur dioxide concentrations remain well below the standards, sulfur dioxide is a precursor to sulfate, which is a component of fine particulate matter, PM_{10}, and $PM_{2.5}$. Standards for PM_{10} and $PM_{2.5}$ were both exceeded in 2006. Sulfur dioxide was not measured at SSAB sites in 2006. 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.

The elderly, people with pre-existing respiratory and/or cardiovascular disease and children appear to be more susceptible to the effects of PM10 and PM2.5.

The SCAQMD monitored PM10 concentrations at 20 locations in 2006. Highest PM10 concentrations were recorded in Riverside and San Bernardino counties in and around the Metropolitan Riverside County area and further inland in San Bernardino Valley areas. The federal 24-hour standard was not exceeded at any of the locations monitored in 2005. The much more stringent state standards were exceeded in most areas.

The SCAQMD began regular monitoring of PM2.5 in 1999 following the U.S. EPA's adoption of the national PM2.5 standards in 1997. In 2005, PM2.5 concentrations were monitored at 19 locations throughout the district. Maximum 24-hour average concentration has increased at some locations compared to 2001, the basis of the 2003 AQMP air quality data. The PM2.5 annual average concentrations and the highest 98th percentile PM2.5 concentrations (which the federal 24-hour PM2.5 standard is based on), however, are lower than 2001 levels at all locations monitored.

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 the metropolitan area of Los Angeles County. 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 two 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 bony tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.

The federal and state standards for lead were not exceeded in any area of the SCAQMD in 2005. There have been no violations of the 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 (0.03 μg/m3) was two percent of the federal standard. Additionally, special monitoring stations immediately adjacent to stationary sources of lead (e.g., lead smelting facilities) have not recorded exceedances of the standards in localized areas of the Basin since 1991 and 1994 for the federal and state standards, respectively. The maximum monthly and quarterly average lead concentration (0.44 μg/m3 and 0.34 μg/m3 in Central Los Angeles), measured at special monitoring sites immediately adjacent to stationary sources of lead were 29 and 23 percent of the state and federal standards, respectively. No lead data were obtained at SSAB and Orange County stations in 2005, and because historical lead data showed concentrations in SSAB and Orange County areas to be well below the standard, measurements have been discontinued.

Sulfates

Sulfates 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 sulfur dioxide. 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 sulfur dioxide at ambient levels are also associated with sulfates. Thus, both mortality and morbidity effects have been observed with an increase in ambient sulfate concentrations. However, efforts to separate the effects of sulfates 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 nonacidic particles like ammonium sulfate. Whether the effects are attributable to acidity or to particles remains unresolved.

In 2005, the state sulfate standard was not exceeded anywhere in the Basin. No sulfate data were obtained at SSAB and Orange County stations in 2005. Historical sulfate data showed concentrations in the SSAB and Orange County areas to be well below the standard, and measurements have been discontinued.

Visibility Reducing Particles

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.

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. They 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.

Greenhouse Gases

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 the following directives:

- 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;
- develop an emissions inventory and control strategy for methyl bromide; and,
- support the adoption of a California greenhouse gas emission reduction goal.

Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse. 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 electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

CO2 is an odorless, colorless natural 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. CH_4 is a flammable gas and is the main component of natural gas. N_2O, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes (fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions) also contribute to its atmospheric load. 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. SF_6 is an inorganic, odorless, colorless, nontoxic, nonflammable gas. SF_6 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. As reported by the California Energy Commission (CEC), California contributes 1.4 percent of the global and 6.2 percent of the national GHGs emissions (CEC, 2004). The GHG inventory for California is presented in Table 3-3 (CEC, 2005). Approximately 80 percent of GHGs in California are from fossil fuel combustion (see Table 3-3).

In June 2005, Governor Schwarzenegger signed Executive Order #S-3-05 which established the following greenhouse gas reduction targets:

- By 2010, Reduce to 2000 Emission Levels,
- By 2020, Reduce to 1990 Emission Levels, and
- By 2050, Reduce to 80 percent below 1990 Levels.

Table 3-3
California GHG Emissions and Sinks Summary
(Million metric tons of CO_2 equivalence)

Gas/Source	1990	2004
Carbon Dioxide (Gross)	**317.4**	**355.9**
Fossil Fuel Combustion	306.4	342.4
Residential	29.0	27.9
Commercial	12.6	12.2
Industrial	66.1	67.1
Transportation	161.1	188.0
Electricity Generation (In State)	36.5	47.1
No End Use Specified	1.1	0.2
Cement Production	4.6	6.5
Lime Production	0.2	0.1
Limestone & Dolomite Consumption	0.2	0.3
Soda Ash Consumption	0.2	0.2
Carbon Dioxide Consumption	0.1	0.1
Waste Combustion	0.1	0.1
Land Use Change & Forestry Emissions	5.5	6.1
Land Use Change & Forestry Sinks	(22.7)	(21.0)
Carbon Dioxide (Net)	**294.7**	**334.9**
Methane (CH4)	**26.0**	**27.9**
Petroleum & Natural Gas Supply System	1.0	0.5
Natural Gas Supply System	1.6	1.4
Landfills	8.1	8.4
Enteric Fermentation	7.5	7.2
Manure Management	3.3	6.0
Flooded Rice Fields	0.4	0.6
Burning Ag & Other Residues	0.1	0.1
Wastewater Treatment	1.4	1.7
Mobile Source Combustion	1.2	0.6
Stationary Source Combustion	1.3	1.3
Nitrous Oxide (N2O)	**32.7**	**33.3**
Nitric Acid Production	0.4	0.2
Waste Combustion	0.0	0.0
Agricultural Soil Management	14.7	19.2
Manure Management	0.8	0.9
Burning Ag Residues	0.1	0.1
Wastewater	0.9	1.1
Mobile Source Combustion	15.6	11.8
Stationary Source Combustion	0.2	0.2
High Global Warming Potential Gases (HFCs, PFCs & SF6)	**7.1**	**14.2**
Substitution of Ozone-Depleting Substances	4.5	12.6
Semiconductor Manufacture	0.4	0.6
Electricity Transmission & Distribution (SF6)	2.3	1.0
Gross California Emissions (w/o Electric Imports)	**383.3**	**431.3**
Land Use Change & Forestry Sinks	**(22.7)**	**(21.0)**
Net Emissions (w/o Electric Imports)	**360.6**	**410.3**
Electricity Imports	**43.3**	**60.8**
Gross California Emissions with Electricity Imports	**426.6**	**492.1**
Net California Emissions with Electricity Imports	**403.9**	**471.1**

Source: CEC, 2005

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. AB32 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." AB32 represents the first enforceable state-wide program in the U.S. 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, AB32 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.

AB32 will require 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 AB32 will require significant development and implementation of energy efficient technologies and shifting of energy production to renewable sources.

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. Some data indicate that the current temperature record differs from previous climate changes in rate and magnitude.

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 400-450 ppm carbon dioxide-equivalent concentration is required to keep global mean warming below 2° Celsius, which is assumed to be necessary to avoid dangerous climate change.

The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, and air quality. 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 (i.e., 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 and hurricanes 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 specifically mentioned in AB 32 such as rising sea levels and changes in snow pack. The extent of climate change impacts at specific locations remains unclear. However, it is expected that California agencies will more precisely quantify impacts in various regions of the State. As an example, it is expected that the 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.

Toxic Air Contaminants

Historically, the 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 toxic air contaminants (TACs) requires a similar regulatory approach as explained in the following subsections.

Control of TACs under the TAC Identification and Control Program

California's TAC identification and control program, adopted in 1983 as Assembly Bill (AB) 1807, is a two-step program in which substances are identified as TACs, and airborne toxic control measures (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 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 state law, a federal National Emission Standard for Hazardous Air Pollutants (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 the 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 (AB2588) 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 AB2588 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.

In October 1992, the SCAQMD Governing Board adopted public notification procedures for Phase I and II facilities. These procedures specify that AB2588 facilities must provide public notice when exceeding the following risk levels:

- Maximum Individual Cancer Risk: greater than 10 in 1 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.

The SCAQMD continues to complete its review of the health risk assessments submitted to date and may require revision and resubmission as appropriate before final approval. Notification will be required from facilities with a significant risk under the AB2588 program based on their initial approved health risk assessments and will continue on an ongoing basis as additional and subsequent health risk assessments are reviewed and approved.

Control of TACs with Risk Reduction Audits and Plans

Senate Bill (SB) 1731, enacted in 1992 and codified at Health and Safety Code §44390 et seq., amended AB2588 to include a requirement for facilities with significant risks to prepare and implement a risk reduction plan which will reduce the risk below a defined significant risk level within specified time limits. SCAQMD Rule 1402 - Control of Toxic Air Contaminants from Existing Sources, was adopted on April 8, 1994, to implement the requirements of SB1731.

In addition to the TAC rules adopted by SCAQMD under authority of AB1807 and SB1731, the SCAQMD has adopted source-specific TAC rules, based on the specific level of TAC emitted and the needs of the area. These rules are similar to the state's ATCMs because they are source-specific and only address emissions and risk from specific compounds and operations.

Cancer Risks from Toxic Air Contaminants

New and modified sources of toxic air contaminants in the SCAQMD are subject to Rule 1401 - New Source Review of Toxic Air Contaminants and Rule 212 - Standards for Approving Permits. Rule 212 requires notification of the SCAQMD's intent to grant a permit to construct a significant project, defined as a new or modified permit unit located within 1000 feet of a school (a state law requirement under AB3205), 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 below), respectively.

Health Effects

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 noncarcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. The California Environmental Protection Agency (CalEPA) Office of Environmental Health Hazard Assessment 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 noncancer 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).

Existing Emissions from Rule 1110.2 Engines

SCAQMD staff conducted a survey in 2005 of non-agricultural, stationary, non-emergency engines. Operators at a total of 580 facilities were contacted, and 313 of those facility operators responded (54 percent facility response rate). The survey collected data for 631 out of a total of 907 active engines (70 percent response rate based on number of engines). Emissions were calculated based on fuel consumption data gathered via the survey, but because source test emissions data often underestimate actual emissions, Rule 1110.2 concentration limits were used for some of the engines to make the estimates more realistic. The resulting calculated total emissions for all survey engines were scaled up to account for the percent response rate by engine category to obtain a complete emissions inventory for the entire universe of regulated engines.

Unannounced Compliance Testing

A program of unannounced compliance testing conducted by SCAQMD's Compliance Division revealed that, although engines can generally meet emission limits when emission control systems are properly maintained and adjusted as is generally the case at the time of source testing; emissions during normal operation frequently exceed the emission limits. The tendency for an engine to have excess emissions will differ depending upon whether it is a rich-burn or lean-burn engine, what emission limits it must meet, BACT or Rule 1110.2, and whether or not it has a CEMS. Newer engines would have been subject to more stringent BACT requirements than the source-specific requirements in Rule 1110.2. Table 3-4 shows the average ratio of measured emissions to allowed emissions found in the testing program with engines categorized based on these three parameters.

Table 3-4
Average Ratio of Measured Emission to Allowed Emission Found in Unannounced Testing

Rich/Lean	Limits	CEMS	Tests	NOx	CO
Lean	BACT	No	3	1.81	0.33
Lean	BACT	Yes	7	0.76	0.39
Lean	Rule	No	1	0.89	0.10
Rich	BACT	No	169	5.19	5.21
Rich	BACT	Yes	8	0.11	37.76
Rich	Rule	No	39	2.12	0.70

In 1993 the SCAQMD adopted Regulation XX – RECLAIM. This regulation established a NOx and SOx cap-and-trade emission reduction market program that required over 300 of the largest emitting facilities in the district to meet the requirements of that program rather than the requirements of specified source-specific SCAQMD Rules. Therefore, while some engines in the district are not subject to the NOx requirements of Rule 1110.2; they are still subject to the VOC and CO requirements of Rule 1110.2.

Excess emissions of both NOx and CO were clearly evident from rich-burn engines with BACT limits not having CEMS. Excess emissions of CO were evident from rich-burn engines with BACT limits having CEMS and of NOx from rich-burn engines with Rule 1110.2 limits not having CEMS. Although there was some suggestion of excess NOx emissions from lean-burn engines with BACT limits not having CEMS, the number of tests was considered too small to be conclusive and, because of the inherently low emissions of this type of engine, lean-burn engines are less likely to have large exceedances. There were no tests on rich-burn engines with Rule 1110.2 limits having CEMS.

To estimate the extent of excess emissions from the entire population of engines in the district (actual emissions), staff applied factors to the allowed emission rates from each engine for which survey data were available. These factors were based on the ratios derived from the results of unannounced testing summarized in Table 3-4. Since VOC emissions were not measured, to estimate excess VOC emissions from each engine, the same CO factor was also applied to the allowed VOC emission rates based on the general observation that these pollutants generally trend together, i.e., rise or fall in the same direction.

Table 3-5 summarizes the calculated emissions based on the survey data, the estimated excess emissions based on the average exceedance factors found in compliance testing and the resulting total calculated/estimated emissions from stationary, non-emergency engines.

Table 3-5
Emissions from Stationary, Non-Emergency Engines

Description	NOx	CO	VOC	SOx	PM-2.5	CO2
Annual, tons/year	1,678	9,947	459	101	160	1,249,971
Daily, pounds/day	9,195	54,506	2,517	551	877	6,849,158

ENERGY

In 2005, 37 percent of the petroleum came from in-state, with 21 percent coming from Alaska, and 42 percent being supplied by foreign sources. Also in 2005, 78 percent of the electricity came from instate sources, while 22 percent was imported into the state. The electricity imported totaled 62,456 gigawatt hours (gW-hours), with 20,286 gW-hours coming from the Pacific Northwest, 42,170 gW-hours from the Southwest. (Note: A gigawatt is equal to one million kilowatts). For natural gas in 2005, 38 percent came from the Southwest, 23 percent from Canada, 15 percent from in-state, and 24 percent from the Rockies.[12]

Electricity Production

Assembly Bill 1890, which was signed into law in 1996, attempted to restructure California's electricity market. Flaws in the market design combined with natural gas supply shortages and a number of other factors to produce an energy crisis in the state that resulted in numerous rolling blackouts, huge electricity price spikes, and bankruptcy or near-bankruptcy for two of the state's private utilities. The legislature responded by rescinding much of the deregulation scheme, creating a new state power authority, and enacting emergency energy conservation measures, mostly in the form of rebates and incentives. Currently, it is not clear whether lawmakers will choose to try again with a restructured market, or return to the former regulated market. This uncertainty has deterred many private investors from pursuing energy projects, meaning that the state, and the region's, future energy supply is far from assured.

Power plants in California provide approximately 85 percent of the in-state electricity demand. Hydroelectric power from the Pacific Northwest provides another 2.6 percent, down due to drought conditions in recent years, and power plants in the Southwestern U.S. provide another 13 percent. The relative contribution of in-state and out-of-state power plants depends upon, among other factors, the precipitation that occurred in the previous year and the corresponding amount of hydroelectric power that is available. Two of the largest power plants in California are located in southern California: Alamitos and Redondo Beach. Both of these plants consume natural gas. San Onofre, the state's largest power plant in terms of net capability, is nuclear powered and is located in San Diego County.

Local electricity distribution service is provided to customers within southern California by one of two privately owned utilities – either Southern California Edison Company or San Diego-based Sempra Energy – or by a publicly-owned utility, such as the Los Angeles Department of Water and Power and the Imperial Irrigation District.

Southern California Edison is the largest electricity utility 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. Southern California Edison Company provides approximately 70 percent of the total electricity demand in southern California. Sempra Energy provides local distribution service to the southern portion of Orange County.

The Los Angeles Department of Water and Power is the largest of the publicly owned electric utilities in southern California. Los Angeles Department of Water and Power provides electricity service to most customers located in the City of Los Angeles and provides approximately 20 percent of the total electricity demand in the Basin. Other cities that operate their own electric utilities in southern California include Burbank, Glendale, Pasadena, Azusa, Vernon, Anaheim, Riverside, Banning, and Colton. Two water districts provide local electric service within the southern California: Imperial Irrigation District and Southern California Water Company. Imperial Irrigation District provides electricity to

[12] CEC, California's Major Source of Energy, December 2005.

customers in Imperial County and the Coachella Valley portion of Riverside County. Southern California Water Company provides electric service to the community of Big Bear. Anza Electric Cooperative provides local distribution service to the Anza Valley area of southern Riverside County.[13]

Table 3-6 shows the amount of electricity delivered to residential and nonresidential entities in the counties in the Basin.

Table 3-6
California Utility Electricity Deliveries for 2000

County	Residential		Non-residential		Total	
	Number of Accounts	kWh[1] (million)	Number of Accounts	kWh (million)	Number of Accounts	kWh (million)
Los Angeles	2,956,616	18,342	356,167	45,577	3,312,783	63,919
Orange	878,934	6,092	120,907	13,612	999,841	19,704
Riverside	500,171	4,396	157,503	6,425	657,674	10,821
San Bernardino	547,654	3,774	67,131	8,093	914,785	11,867
Total	4,883,375	32,604	701,708	73,707	5,885,083	106,311

California Energy Commission, California Gross System Electricity Production for 2005, December 2005.
[1] kilowatt-hour (kWh): The most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt (1000 watts) of electricity supplied for one hour.

Natural Gas

Four regions supply California with natural gas. Three of them—the Southwestern U.S., the Rocky Mountains, and Canada—supplied 87 percent of all the natural gas consumed in California in 2004. The remainder is produced in California. In 2004, approximately 50 percent of all the natural gas consumed in California was used to generate electricity. Residential consumption represented approximately 22 percent of California's natural gas use with the balance consumed by the industrial, resource extraction, and commercial sectors.

Southern California Gas Company, a privately-owned utility company, provides natural gas service throughout the district, except for the City of Long Beach, the southern portion of Orange County, and portions of San Bernardino County. The service area for the Long Beach Gas & Electric Department, a municipal utility owned and operated by the City of Long Beach, includes the cities of Long Beach and Signal Hill, and sections of surrounding communities, including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. San Diego Gas & Electric Company provides natural gas service to the southern portion of Orange County. In San Bernardino County, Southwest Gas Corporation provides natural gas service to Victorville, Big Bear, Barstow, and Needles.[14]

Table 3-7 provides the estimated use of natural gas in California by residential, commercial and industrial sectors. In 2005, about 67 percent of the natural gas consumed in California was for industrial and electric generation purposes.

[13] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005
[14] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005 and CEC, 2004 Natural Gas Use in California.

Table 3-7
California Natural Gas Demand 2005
(Million Cubic Feet per Day – MMcf/day)

Sector	Utility	Non-Utility	Total
Residential	1,286	--	1,286
Commercial	567	--	567
Industrial	844	630	1,474
Electric Generation	1,711	683	2,394
Total	4,419	1,313	5,732

Source: CEC, California Natural Gas Demand -2005, 2006.

Liquid Petroleum Fuels

California is currently ranked fourth in the nation among oil producing states, behind Louisiana, Texas, and Alaska, respectively. Crude oil production in California averaged 731,150 barrels per day in 2004, a decline of 4.7 percent from 2003. Statewide oil production has declined to levels not seen since 1943. In 2005, the total receipts to refineries of roughly 674 million barrels came from in-state oil production (39.4 percent), combined with oil from Alaska (20.1 percent), and foreign sources (40.4 percent).[15]

California is a major refining center for West Coast petroleum markets with combined crude oil distillation capacity totaling more than 1.9 million barrels per day, ranking the state third highest in the nation. California ranks first in the U.S. in gasoline consumption and second in jet fuel consumption.

A large network of crude oil pipelines connects producing areas with refineries that are located in the San Francisco Bay area, Los Angeles area and the Central Valley. Major ports in northern and southern California receive Alaska North Slope and foreign crude oil for processing in many of the state's 21 refineries.

Most gasoline and diesel fuel sold in California for on-road motor vehicles is refined in California to meet state-specific formulations required by CARB. Major petroleum refineries in California are concentrated in three counties: Contra Costa County in northern California, Kern County in central California, and Los Angeles County in southern California. In Los Angeles County, petroleum refineries are located mostly in the southern portion of the county.[16]

In 2001, refineries in California processed approximately 655 million barrels of crude oil. Almost half of the crude oil came from in-state oil production facilities; 21 percent came from Alaska; and the remaining (approximately 29 percent) came from foreign sources. The long-term oil supply outlook for California remains one of declining in-state and Alaska supplies leading to increasing dependence on foreign oil sources.[16]

California's Renewable Energy Program

California's Renewable Portfolio Standard (RPS) was developed under Senate Bills 1038, 1078, 1250 and 107. The senate bills require retail sellers of electricity to increases the

[15] CEC, Oil and Petroleum in California, December 2006.

[16] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005 and CEC, 2004 Natural Gas Use in California.

amount of renewable energy they procure by one percent each year until 20 percent of total retail sales are served with renewable energy by December 31, 2010.

The Energy Commission's 2003 Integrated Energy Policy Report recommended accelerating that goal to 2010, and the 2004 Energy Report Update further recommended increasing the target to 33 percent by 2020. The state's Energy Action Plan supported this goal.

On April 25, 2006, Governor Schwarzenegger signed Executive Order S-06-06. The Executive Order established targets for the production and use of biofuels and biopower, and directed state agencies with important biomass connections to work together to advance biomass programs in California, while providing environmental protection and mitigation. The Executive Order S-06-06 targets 20 percent biofuel by 2010, 40 percent by 2020 and 75 by 2050. Governor Schwarzenegger targeted biomass to contribute 20 percent of the goal for renewable electricity generated under RPS for the 2012 and 2020 goals.

The CEC's Renewable Energy Program (REP) provides funding for renewable facilities as long as 25 percent of the total energy input was comprised of energy from fossil fuels during a calendar year. Any facility that is developed and awarded a power purchase contract as a result of an Interim RPS procurement solicitation approved by the CPUC under Decisions 02-08-071 and 02-10-062 may use up to 25 percent fossil fuel and attribute 100 percent of the electricity generated as RPS-eligible.[17]

In 2002, the total electrical generation capacity from existing landfill gas to electricity projects in California was 211 MW. At that time there were 26 planned landfill gas to energy facilities with a potential of 39 MW. Approximately 45 MW of electrical potential was projected if existing landfill gas to energy projects were expanded to full capacity. Approximately 163 MW was estimated to be available from landfills that did not generate electricity at the time.

The CEC Reconciliation of Retailer Claims, Commission Report presents a table of the 2005 Gross System Power by fuel type. The table is reproduced here as Table 3-8.

[17] California Energy Commission, Renewable Portfolio Standard Eligibility, Second Edition, CEC-300-2007-006-CMF, March 2007.

Table 3-8
2005 Gross System Power[18]

Fuel Type	System Power
Eligible Renewable	10.7%
-Biomass & waste	2.1%
-Geothermal	5.0%
-Small hydroelectric	1.9%
-Solar	0.2%
-Wind	1.5%
Coal	20.1%
Large hydroelectric	17.0%
Natural gas	37.7%
Nuclear	14.5%
Other	0.0%
Total	100.00%

Table 3-9 shows the percentage of system power by renewable fuel type based on the values in Table 3-8. As seen in Table 3-9, biomass and waste comprises 20 percent of the eligible renewable energy.

Table 3-9
2005 Renewable System Power

Fuel Type	System Power
Biomass & waste	20%
Geothermal	47%
Small hydroelectric	18%
Solar	2%
Wind	14%
Total	100%

The RPS has consists of three utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. SCE provides most of the electricity for the district. Table 3-10 shows that of the total renewable energy procurement SCE provides 66 percent of the state biogas and no municipal solid waste to the RPS. Table 3-11 shows that of the total renewable energy procurement SDG&E provides 20 percent of the state biogas and no municipal solid waste to the RPS.

[18] California Energy Commission, Reconciliation of Retailer Claims, Commission Report, CEC-300-2006-016-F, October 2006.

Table 3-10
2005 SCE Renewable System Power[19]

Fuel	Total Procurement (MW-hour)	SCE Procurement (MW-hour)	Percent of SCE Procurement	Percent of Total Procurement
Biomass	3,614,079	379,119	3%	10%
Biogas	1,110,233	737,262	6%	66%
Geothermal	9,504,152	7,823,442	61%	82%
Municipal Solid Waste	139,882	0	0%	0%
Small Hydro	3,743,740	867,171	7%	23%
Solar	622,100	622,100	5%	100%
Wind	3,665,933	2,495,301	19%	68%
Various From Net Metering	0	0	0%	
Total Renewable Procurement	22,400,119	12,924,395	100%	58%

Table 3-11
2005 SDG&E Renewable System Power[20]

Fuel	Total Procurement (MW-hour)	SDG&E Procurement (MW-hour)	Percent of SDG&E Procurement	SDG&E Percent of Total Procurement
Biomass	3,614,079	298,945	36%	8%
Biogas	1,110,233	218,223	26%	20%
Geothermal	9,504,152	0	0%	0%
Municipal Solid Waste	139,882	0	0%	0%
Small Hydro	3,743,740	11,764	1%	0%
Solar	622,100	0	0%	0%
Wind	3,665,933	296,434	36%	8%
Various From Net Metering	0	0	0%	
Total Renewable Procurement	22,400,119	825,366	100%	4%

In-state electricity from biomass comprises two percent of the total electricity capacity in California and more than two percent to its electrical energy supply. In Executive Order S-06-06 Governor Schwarzenegger targeted biomass to contribute 20 percent of the goal for renewable electricity generated under RPS. Table 3-12 presents biomass capacities for California.

The CEC states that 305 MW are available from landfill gas operations and 68 MW from digester gas operations in California. Based on 974 MW of total biomass electrical capacity in the state landfill gas operations could provide 31 percent of the total potential biomass electrical capacity and digester operations could provide 38 percent of the total potential biomass electrical capacity. The total potential biomass electrical capacity is the amount of electricity available from all existing and future biomass sources. The term “potential” is used because not all of the sources may be converted to electricity producing sources.

[19] California Energy Commission, Renewable Portfolio Standard 2005 Procurement Verification, Staff Draft Report, CEC-300-2007-001-SD, March 2007
[20] CEC, March 2007, ibid.

Table 3-12
Biomass Capacities

Facility Type	Total State MW Capacity[21]	Existing State MW Capacity[22]	Existing SCAB MW Capacity[23]
Direct Combustion	602		
Landfill Gas	305	244	143.9
Wastewater	65	46.810	26.490
Animal Food Waste	3	3	1.660

HAZARDS AND HAZARDOUS MATERIALS

The reduction of NOx, emissions pursuant to the proposed amendments to PAR 1110.2 may affect the use, storage and transport of hazards and hazardous materials. New (or modifications to existing) air pollution control equipment (e.g., SCRs) and related components are expected to be installed at some of the affected facilities such that their operations may increase the quantity of hazardous materials (e.g., spent catalyst modules) generated by the control equipment and may increase the quantity of ammonia used. The primary effects of the proposed amendments to PAR 1110.2 with respect to hazards and hazardous materials are the anticipated overall increase in the amount of ammonia injected into SCR units for controlling NOx emissions from ICEs, the increase of ammonia slip emissions, and the increase of spent catalyst.

Ammonia is the primary hazardous chemical identified with the proposed project. Ammonia, though not a carcinogen, can have chronic and acute health impacts. Therefore, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the facilities that currently use or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud and migrate off-site, thus exposing individuals. Anhydrous ammonia is heavier than air such that when released into the atmosphere, would form a cloud at ground level rather than be dispersed "Worst-case" conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse. Though there are facilities that may be affected by the proposed rule amendments and that are currently permitted to use anhydrous ammonia, for new construction, however, current SCAQMD policy no longer allows the use of anhydrous ammonia. Instead, to minimize the hazards associated with ammonia used in the SCR process, aqueous ammonia, 19 percent by volume, is typically required as a permit condition associated with the installation of SCR equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and, 2) 19 percent aqueous ammonia is not on any acutely hazardous material lists unlike anhydrous ammonia or aqueous ammonia at higher percentages.

In addition, the shipping, handling, storage, and disposal of hazardous materials inherently poses a certain risk of a release to the environment. Thus, the routine transport of hazardous

[21] CEC, A Preliminary Roadmap for the Development of Biomass in California CEC 5000-2006-095-D, Dec 2006.
[22] California Biomass Collaborative, California Biomass Facilities Reporting System (BFRS), http://biomass.ucdavis.edu/pages/report_system.htm, June 2007.
[23] California Biomass Collaborative, June 2007, ibid.

materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project. Further, if the control option chosen by each affected facility is to install SCR, the proposed project may alter the transportation modes for feedstock and products to/from the existing facilities such as aqueous ammonia and catalyst.

Commercial catalysts used in SCRs are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), or iron oxide (Fe_2O_3). The key hazards associated with the proposed project are the crushing of the spent catalyst and transporting it for disposal or recycling. With respect to hazards and hazardous materials, this means that there will be an increase in the frequency of truck transportation trips to remove the spent catalyst as hazardous materials or hazardous waste from each affected facility. However, facilities that have existing catalyst-based operations currently recycle the catalysts blocks, in lieu of disposal. Moreover, due to the heavy metal content and relatively high cost of catalysts, recycling can be more lucrative than disposal. Thus, facilities that have existing SCR units and choose to employ additional SCR equipment to comply with the proposed amendments to PAR 1110.2, in most cases already recycle the spent catalyst and subsequently may continue to do so with the additional catalyst that may be needed.

Although recycling may be the more popular consideration, it is possible that facilities may choose to dispose of the spent catalyst in a landfill. The composition and type of the catalyst will determine the type of landfill that would be eligible to handle the disposal. For example, catalysts with a metal structure would be considered a metal waste, like copper pipes, and not a hazardous waste. Therefore, metal structure catalysts would not be a regulated waste requiring disposal in a Class I landfill unless it is friable or brittle. As ceramic-based catalysts contain a fiber-binding material, they are not considered friable or brittle and thus, would not be a regulated waste requiring disposal in a Class I landfill. Furthermore, typical catalyst materials are not considered to be water soluble, which also means they would not require disposal in a Class I landfill. In both cases, spent catalyst would not require disposal in a Class I landfill.

Based on the above information, it is likely that spent catalysts would be considered a "designated waste," which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (California Code of Regulations, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class II landfill or a Class III landfill that is fitted with liners.

Disposal of spent catalyst would typically involve crushing the material and encasing it in concrete prior to disposal. Since it is expected that most spent catalysts will be recycled and regenerated, it is anticipated that there will be sufficient landfill capacity in the district to accommodate disposal of any spent catalyst materials

A number of physical or chemical properties may cause a substance to be hazardous, including toxicity (health), flammability, reactivity, and any other specific hazard such as corrosivity or radioactivity. Based on a hazard rating from 0 to 4 (0 = no hazard; 4 = extreme hazard) located on the Material Safety Data Sheet (MSDS) the hazard rating for silica/alumina catalyst, for example, health is rated 1 (slightly hazardous), flammability is rated 0 (none) and reactivity is rated 0 (none). However, if nickel is deposited on the catalyst, the hazard rating is 2 for health (moderately toxic), 4 (extreme fire hazard) for flammability, 1 for reactivity (slightly hazardous if heated or exposed to water). The particular composition of the catalyst used in the SCR units, combined with the metals content of the flue gas will determine the hazard rating and whether the spent catalyst is considered a hazardous material or hazardous waste. This distinction is important because a spent catalyst that qualifies as a hazardous material could be recycled or reused by another industry (such as manufacturing California Portland cement). However, spent catalyst that is considered hazardous waste must be disposed of in a Class III landfill.

The use, storage and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage and transportation of hazardous materials. Risk of upset concerns is related to the risks of explosions or the release of hazardous substances in the event of an accident or upset conditions.

Hazardous Materials Management Planning

State law requires detailed planning to ensure that hazardous materials are properly handled, used, stored, and disposed of to prevent or mitigate injury to health or the environment in the event that such materials are accidentally released. Federal laws, such as the Emergency Planning and Community-Right-to-Know Act of 1986 (also known as Title III of the Superfund Amendments and Reauthorization Act or SARA, Title III) impose similar requirements. These requirements are enforced by the California Office of Emergency Services.

The Hazardous Materials Release Response Plans and Inventory Law of 1985 (Business Plan Act) requires that any business or government agency that handles hazardous materials prepare a business plan, which must include the following (HSC §25504):

- details, including floor plans, of the facility and business conducted at the site;
- an inventory of hazardous materials that are handled or stored on the site;
- an emergency response plan; and
- a training program in safety procedures and emergency response for new employees, and an annual refresher course in the same topics for all employees.
-

Hazardous Materials Transportation

The United States Department of Transportation (DOT) has the regulatory responsibility for the safe transportation of hazardous materials between states and to foreign countries. DOT regulations govern all means of transportation, except for those packages shipped by mail, which are covered by the United States Postal Service (USPS) regulations. DOT regulations are contained in the Code of Federal Regulations, Title 49 (49 CFR); USPS regulations are in 39 CFR.

Every package type used by a hazardous materials shipper must undergo tests which imitate some of the possible rigors of travel. While not every package must be put through every test, most packages must be able to meet the following generic test criteria: the ability to be (a) kept under running water for one-half hour without leaking; (b) dropped, fully loaded, onto a concrete floor; (c) compressed from both sides for a period of time; (d) subjected to low and high pressure; and (e) frozen and heated alternately.

Common carriers are licensed by the California Highway Patrol (CHP) pursuant to the California Vehicle Code, §32000, which requires licensing of every motor (common) carrier who transports, for a fee, in excess of 500 pounds of hazardous materials at one time and every carrier, if not for hire, who carries more than 1,000 pounds of hazardous material of the type requiring placards. Common carriers conduct a large portion of their business in the delivery of hazardous materials.

Under the federal Resource Conservation and Recovery Act (RCRA) of 1976, the EPA set standards for transporters of hazardous waste. In addition, the State of California regulates the transportation of hazardous waste originating or passing through the state; state regulations are contained in the California Code of Regulations (CCR), Title 13. Hazardous waste must be regularly removed from generating sites by licensed hazardous waste transporters. Transported materials must be accompanied by hazardous waste manifests.
Two state agencies have primary responsibility for enforcing federal and state regulations and responding to hazardous materials transportation emergencies: the CHP and the California Department of Transportation (Caltrans).

The CHP enforces hazardous materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an accident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of CHP, which conducts regular inspections of licensed transporters to assure regulatory compliance. Caltrans has emergency chemical spill identification teams at 72 locations throughout the state.

Hazardous Material Worker Safety Requirements

The California Occupational Safety and Health Administration (Cal/OSHA) and the Federal Occupational Safety and Health Administration (Fed/OSHA) are the agencies responsible for assuring worker safety in the handling and use of chemicals in the workplace. In California, Cal/OSHA assumes primary responsibility for developing and enforcing workplace safety regulations.

Under the authority of the Occupational Safety and Health Act of 1970, Fed/OSHA has adopted numerous regulations pertaining to worker safety (contained in 29 CFR – Labor). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage. Because California has a federally-approved OSHA program, it is required to adopt regulations that are at least as stringent as those found in 29 CFR.

Cal/OSHA regulations concerning the use of hazardous materials in the workplace (which are detailed in CCR, Title 8) include requirements for employee safety training, availability of safety equipment, accident and illness prevention programs, hazardous substance exposure warnings, and emergency action and fire prevention plan preparation. Cal/OSHA enforces hazard communication program regulations, which contain training and information requirements, including procedures for identifying and labeling hazardous substances as well as communicating hazard information related to hazardous substances and their handling. The hazard communication program also requires that Material Safety

Data Sheets (MSDSs) be available to employees and that employee information and training programs be documented. These regulations also require preparation of emergency action plans (escape and evacuation procedures, rescue and medical duties, alarm systems, and emergency evacuation training).

Both federal and state laws include special provisions for hazard communication to employees in research laboratories, including training in chemical work practices. The training must include methods in the safe handling of hazardous materials, an explanation of MSDSs, use of emergency response equipment and supplies, and an explanation of the building emergency response plan and procedures.

Chemical safety information must also be available. More detailed training and monitoring is required for the use of carcinogens, ethylene oxide, lead, asbestos, and certain other chemicals listed in 29 CFR. Emergency equipment and supplies, such as fire extinguishers, safety showers, and eye washes, must also be kept in accessible places. Compliance with these regulations reduces the risk of accidents, worker health effects, and emissions.

National Fire Codes (NFC), Title 45 (published by the National Fire Protection Association) contains standards for laboratories using chemicals, which are not requirements, but are generally employed by organizations in order to protect workers. These standards provide basic protection of life and property in laboratory work areas through prevention and control of fires and explosions, and also serve to protect personnel from exposure to non-fire health hazards.

While NFC Standard 45 is regarded as a nationally recognized standard, the *California Fire Code* (24 CCR) contains state standards for the use and storage of hazardous materials and special standards for buildings where hazardous materials are found. Some of these regulations consist of amendments to NFC Standard 45. State Fire Code regulations require emergency pre-fire plans to include training programs in first aid, the use of fire equipment, and methods of evacuation.

Hazardous Waste Handling Requirements

The RCRA created a major new federal hazardous waste regulatory program that is administered by the EPA. Under RCRA, the EPA regulates the generation, transportation, treatment, storage, and disposal of hazardous waste from “cradle to grave.”

RCRA was amended in 1984 by the Hazardous and Solid Waste Act (HSWA), which affirmed and extended the “cradle-to-grave” system of regulating hazardous wastes. HSWA specifically prohibits the use of certain techniques for the disposal of some hazardous wastes.

Under RCRA, individual states may implement their own hazardous waste programs in lieu of RCRA as long as the state program is at least as stringent as federal RCRA requirements. The EPA approved California’s program to implement federal regulations as of August 1, 1992.

The Hazardous Waste Control Law (HWCL) is administered by the California Environmental Protection Agency Department of Toxic Substance Control (DTSC). Under HWCL, DTSC has adopted extensive regulations governing the generation, transportation, and disposal of hazardous wastes. HWCL differs little from RCRA; both laws impose "cradle to grave" regulatory systems for handling hazardous wastes in a manner that protects human health and the environment. Regulations implementing HWCL are generally more stringent than regulations implementing RCRA.

Regulations implementing HWCL list over 780 hazardous chemicals as well as 20 to 30 more common materials that may be hazardous; establish criteria for identifying, packaging and labeling hazardous wastes; prescribe management practices for hazardous wastes; establish permit requirements for hazardous waste treatment, storage, disposal and transportation; and identify hazardous wastes that cannot be disposed of in landfills.

Under both RCRA and HWCL, hazardous waste manifests must be retained by the generator for a minimum of three years. Hazardous waste manifests list a description of the waste, its intended destination and regulatory information about the waste. A copy of each manifest must be filed with DTSC. The generator must match copies of hazardous waste manifests with certification notices from the treatment, disposal, or recycling facility.

Emergency Response to Hazardous Materials and Wastes Incidents

Pursuant to the Emergency Services Act, the State has developed an Emergency Response Plan to coordinate emergency services provided by federal, state, and local government agencies and private persons. Response to hazardous materials incidents is one part of this plan. The Plan is administered by the state Office of Emergency Services (OES), which coordinates the responses of other agencies including EPA, CHP, the Department of Fish and Game, the Regional Water Quality Control Board (RWQCB), and local fire departments. (See *California Government Code* §8550.)

In addition, pursuant to the Hazardous Materials Release Response Plans and Inventory Law of 1985 (the Business Plan Law), local agencies are required to develop "area plans" for response to releases of hazardous materials and wastes. These emergency response plans depend to a large extent on the business plans submitted by persons who handle hazardous materials. An area plan must include pre-emergency planning of procedures for emergency response, notification and coordination of affected government agencies and responsible parties, training, and follow-up.

SOLID WASTE

The Hazardous Materials Transportation Act is the federal legislation regulating the trucks that transport hazardous wastes. The primary regulatory authorities are the U.S. DOT, the Federal Highway Administration, and the Federal Railroad Administration. The Hazardous Materials Transportation Act requires that carriers report accidental releases of hazardous materials to the Department of Transportation at the earliest practicable moment (49 CFR Subchapter C, Part 171).

The DTSC is responsible for the permitting of transfer, disposal, and storage facilities. The Department of Toxic Substances Control conducts annual inspections of hazardous waste facilities. Other inspections can occur on an as-needed basis.

Caltrans sets standards for trucks transporting hazardous wastes in California. The regulations are enforced by the CHP. Trucks transporting hazardous wastes are required to maintain a hazardous waste manifest. The manifest is required to describe the contents of the material within the truck so that wastes can readily be identified in the event of a spill.

With regard to solid non-hazardous wastes, the California Integrated Waste Management Act of 1989 (AB 939), as amended, requires each county to prepare a countywide siting element which identifies how the county and the cities within the county will address the need for 15 years of disposal (landfill and/or transformation i.e., waste-to energy facilities) capacity to safely handle solid waste generated in the county, which remains after recycling, composting, and other waste diversion activities. AB 939 has recognized that landfills and transformation facilities are necessary components of any integrated solid waste management system and an essential component of the waste management hierarchy. AB 939 establishes a hierarchy of waste management practices in the following order and priority: (1) source reduction; (2) recycling and composting; and (3) environmentally safe transformation/land disposal.

Solid Waste Management

Permit requirements, capacity, and surrounding land use are three of the dominant factors limiting the operations and life of landfills. Landfills are permitted by the local enforcement agencies with concurrence from the California Integrated Waste Management Board (CIWMB). Local agencies establish the maximum amount of solid waste which can be received by a landfill each day and the operational life of a landfill. Landfills are operated by both public and private entities[24]. Landfills in the district are also subject to requirements of the SCAQMD as they pertain to gas collection systems, dust and nuisance impacts.

Landfills throughout the region typically operate between five and seven days per week. Landfill operators weigh arriving and departing deliveries to determine the quantity of solid waste delivered. At landfills that do not have scales, the landfill operator estimates the quantity of solid waste delivered (e.g., using aerial photography). Landfill disposal fees are determined by local agencies based on the quantity and type of waste delivered. Fees vary by landfill and county.

A total of 25 Class III active landfills and two transformation facilities are located within the district. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there are approximately 750,846,000 cubic yards (1,250,367,507 tons) of remaining capacity at Class II and III facilities in Los Angeles, Orange County, Riverside and San Bernardino that accept construction waste.

Hazardous Waste Management

Hazardous material, as defined in 40 CFR 261.20 and 22 CCR Article 9, is disposed of in Class I landfills. California has enacted strict legislation for regulating Class I landfills. The California Health and Safety Code requires Class I landfills to be equipped with liners, a leachate collection and removal system, and a ground water monitoring system. There are no hazardous waste disposal sites within the jurisdiction of the SCAQMD.

Hazardous waste generated at area facilities, which is not reused on-site, or recycled offsite, is disposed of at a licensed in-state hazardous waste disposal facility. There are three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA or Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors

[24] CIWMB, Used Oil Facts, 2007.

Buttonwillow and Westmorland have a remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036.

CHAPTER 4

ENVIRONMENTAL IMPACTS

INTRODUCTION

The state 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].

State 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. For example, the environmental document for projects, such as the adoption or amendment of a comprehensive zoning ordinance or a local general plan, should focus on the secondary effects that can be expected to follow from the adoption or amendment, but the analysis need not be as detailed as the analysis of the specific construction projects that might follow. As a result, this ~~Draft~~Final 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 state CEQA Guidelines, there are approximately 17 environmental categories in which potential adverse impacts from a project are evaluated. Projects are evaluated against the environmental categories in an Environmental Checklist and 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 D) and circulated along with an NOP/IS for a 30-day public review period. Of the 17 potential environmental impact categories, four (air quality, energy, hazards and hazardous material, and solid/hazardous waste) were identified as being potentially significantly adversely affected by the proposed project. During the public comment period SCAQMD received two comment letters on the NOP/IS. The comment letters and individual responses to comments in each comment letter are included in Appendix E.

As already indicated, the following environmental topic areas: air quality, hazards and hazardous material, and solid/hazardous waste were identified in the NOP/IS as areas that could potentially be adversely affected by the proposed project and are comprehensively analyzed further in this EA. Aesthetics and energy impacts are also evaluated in this EA based on comments received during the public review period for the NOP/IS. The environmental impact analysis for each environmental topic typically 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. In some instances the “worst-case” assumption may not be feasible or possible. In this situation, additional assumptions are made such that reasonable “worst-case” assumptions are assumed for the analysis. This process ensures that all potential effects of the proposed project are documented for the decision-makers and the public.

Accordingly, the following analyses use a reasonable “worst-case” approach for analyzing the potentially significant adverse environmental impacts associated with the implementation of the proposed project.

New Projects

PAR 1110.2 includes requirements for new ICEs. PAR 1110.2 requires that new stationary, non-emergency generators must meet the CARB 2007 standards (Distributed Generation Certification Program, Article 3, Subchapter 8, Chapter 1, Division 30, Title 17 for the California Code of Regulations. These standards have been in effect since January 1, 2007. Other new ICEs would need to meet emissions standards which are already required by the existing rule or BACT which is already required for new equipment. New equipment may need additional monitoring and reporting equipment; however the installation of new monitoring and reporting equipment should have minor environmental impacts compared to the installation of the new ICE. Operators/owners that install new ICEs for any other reason than to replace existing ICEs to comply with PAR 1110.2 are outside the scope of this proposed project. New engines would be required to enter the permit process before construction. All permitted equipment is required to have a CEQA evaluation. Impacts from the construction of new engines would be evaluated at that time. Adverse impacts from the new project will be evaluated during the CEQA review during permitting.

Since operators/owners have other options beside ICEs, such as fuel cells, boilers, gas turbines, microturbines, etc., it is speculative to assess the environmental adverse impacts from future new projects in this document. Therefore, no further analysis of new projects has been prepared for this project.

<u>**Changes to PAR 1110.2 Since the Release of the Draft EA for Public Review**</u>

<u>**Additional Exceptions**</u>

<u>To give operators some additional flexibility, the 10 percent natural gas condition was modified to be based on the facility average rather than for each engine. Several biogas engine operators commented on PAR 1110.2 stating that the 10 percent limit could lead to increased flaring of biogas. One said it could cause a blower engine to shut down, resulting in more flaring of digester gas. Another said that at times there might be insufficient digester gas to run an engine at the minimum load necessary for operation stable operation and with emissions in compliance with permit limits. Another said that some natural gas may be needed in the future if the heating value of landfill gas declines to a level below that needed for proper engine operation.</u>

Another sewage treatment plant operator reported that the 10 percent limit would force a reduction in engine load, and reduce the thermal energy recovered by their waste heat boiler that provides heat to their digesters. At times, the recovered waste heat would not be enough to operate the digesters, and the facility does not have boilers to back up or supplement the engines. The facility operator estimates that three months out of the year more than 10 percent natural gas would be required.

PAR 1110.2 authorizes the Executive Officer (EO) to approve more than 10 percent natural gas in these limited situations. Operators must apply for a change of permit conditions and demonstrate the need for the additional natural gas. The EO will evaluate each case and put appropriate conditions on each permit that will allow the additional natural gas use, but only under conditions when it is deemed necessary.

PAR 1110.2 allows operators to exclude from the calculation of the natural gas percentage the natural gas used in a few situations. One operator asked to be able to use more than 10 percent natural gas when rainy weather causes the sewage treatment plant to operate above its design capacity, requiring the highest use of electrical power for pumps and other equipment. During rainy weather, air quality is at its best and the impact of the higher emissions should be minimal.

The same operator said that plant reliability would be improved if they could increase engine loads, with more natural gas use, when grid electric power is short and rolling brownouts are likely. Allowing this during Stage 2 electrical emergencies has other emission benefits. If the brownout does occur at the facility, the plant's backup diesel generators, which have much higher emissions than the biogas engines, would not have to provide as much of the facility's power requirement, and overall emissions would be reduced. Also, by increasing electrical power output during the Stage 2, brownouts might even be avoided, which prevents widespread backup diesel generator use.

A commenter on PAR 1110.2 stated that lean-burn and RELCAIM engines meet the 2,000 ppm CO limit without oxidation catalyst. An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2,000 ppm. The engines would still be subject to the I&M plans.

Standards for New Distributed Generation Equipment

Staff originally proposed emission standards that, as of January 1, 2007, CARB already enforce the above standards for distributed generation equipment that do not require local district permits. The CARB standards are based on the emissions from large new central generating stations with BACT. Since large and small electrical generators are already required to meet these standards, the proposed standards will simply extend the same requirements ICEs that require SCAQMD permits. This was the goal of SB1298 as previously described in Chapter 1. However, the Engine Manufacturers Association commented that by increasing the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC, some advanced engines may be able to comply.

Analysis of New Changes to PAR 1110.2

Emergency and Rainy Day Exemptions

The new exceptions to the monthly 10 percent requirement were added to address either emergency operations or extremes in weather. Since emergencies and extremes in weather cannot be predicted, adverse impacts from these changes are considered to be speculative and will not be addressed in the Final EA.

Exception for ICEs That Are Used to Heat Digesters

Emission increases for facility that would need to run more than 10 percent natural gas over three months a year to supplement heat to the digesters were estimated and presented in Table 4-0a. Detailed calculations can be found at the end of Appendix C. Table 4-0b shows that the additional emissions from the exception for ICEs that are used to heat digesters would not increase criteria pollutants that are less than significant to become significant. PM2.5 was determined to be significant in the Draft EA. The additional PM2.5 from the waste heat boiler would increase project PM2.5 emissions by approximately one pound. The additional PM2.5 increase is less than the SCAQMD CEQA threshold of 55 pounds per day. Therefore, the additional PM2.5 emissions are not considered a substantial increase in the severity of an adverse environmental impact that would require recirculation. The additional emissions have been added to the emission tables in the air quality section.

Table 4-0a
Summary of Exception for Natural Gas for Waste Heat Recovery Boilers

Description	NOx Emissions, lb/day	CO Emissions, lb/day	VOC Emissions, lb/day	SOx Emissions, lb/day	PM10 Emissions, lb/day	PM2.5 Emissions, lb/day
ICE	5.41	32.85	8.84	0.6	0.88	0.87

Table 4-0b
Update to Proposed Project Emissions

Description	NOx Emissions, lb/day	CO Emissions, lb/day	VOC Emissions, lb/day	SOx Emissions, lb/day	PM10 Emissions, lb/day	PM2.5 Emissions, lb/day
Boiler Exception	5.41	32.85	8.84	0.6	0.88	0.87
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No*

Quarterly Monitoring Exemption

SCAQMD staff believes that lean-burn engines that are subject or Regulation XX or have a NOx CEMs would meet the 2,000 ppm CO emissions limit. Even though an exception from quarterly monitoring was added, operators would still need to prepare an I&M plan for these engines. The I&M plan will assist operators with finding engine malfunctions and to correct air-to-fuel ratios to assure proper engine operation, which will reduce emissions.

Revision to the New Engine Emission Requirements

The use of new CARB 2007 Distributed Generated Certification compliant engines was not expected to generate any greater adverse impacts than new distributed generators that are compliant with the existing Rule 1110.2 and BACT, with the exception of air quality. CARB 2007 Distributed Generated Certification compliant engines would generate less NOx, VOC and CO. That is, new CARB 2007 Distributed Generated Certification compliant engines are expected to look similar to new engines that are compliant with the existing Rule 1110.2 with BACT, use similar amounts of energy, generate similar amounts of wastes, and generate similar off-site accidental releases. The choice of installation of one new engine over another would not affect any agricultural resources, biological resources, cultural resources, hydrology/water quality, geology/soil, land use/planning, mineral resources, noise, population/housing, public services, recreation or transportation/traffic.

The revision of CO and VOC limits would still achieve the same NOx reductions as the original proposal, and for an electrical generator without heat recovery, the revised limits will still achieve an 89 percent reduction of CO and a 77 percent reduction of VOC, compared to the current BACT limits for typical new engines. Even though SCAQMD is in attainment for CO, the CO limit is still necessary because CO contributes to ozone formation and it is a good indicator of catalyst performance, and unlike VOC, can be easily monitored by a CEMS or a portable analyzer. In addition, the number of new distributed engines is unknown and therefore adverse impacts from these engines were considered speculative and not evaluated in the Final EA.

Aesthetics

In the NOP, SCAQMD staff stated that PAR 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement. Operators at commercial and industrial facilities may install new, retrofit or replace existing ICEs, control technologies, and/or monitoring equipment. The equipment would be placed within the boundaries of existing commercial or industrial facilities near existing ICE systems. The NOP/IS concluded that installation of retrofit control equipment such as oxidation catalyst systems, for example, would not be substantially different in appearance than existing muffler systems. A CEMS equipment housing may need to be built to protect the system from the weather and, therefore, would not be substantially different in physical appearance than the other existing commercial or industrial equipment at these facilities. It was concluded that because retrofitted, replaced and/or new equipment would not be substantially different in size in appearance than existing equipment the proposed project would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to: trees, rock outcroppings, or historical buildings.

Subsequent to the release of the NOP/IS, it was determined that operators of some biogas facilities may choose to replace ICEs with biogas to LNG facilities, gas turbines, microturbines, boilers or fuel cells. These types of equipment could change the visual character of the affected facilities, thus, potentially creating adverse aesthetics impacts. This potential impact is evaluated in the "Biogas Facilities" discussion below.

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Non-Biogas Engines – New, Retrofit or Replacement Equipment

The conclusions in the NOP/IS still apply to operators of affected engines who choose to retrofit, replace or add new equipment to existing non-biogas ICE engines. Retrofitted engines would not create significant adverse aesthetics impacts since these equipment would be similar in size and character to existing engines.

Non-Biogas Engines – Replacement with Electric Motors and Emergency ICE

As part of the CEQA analysis, based on cost estimates SCAQMD staff identified 225 non-biogas engines where operators would incur lower compliance costs if they replaced existing ICEs with electric motors instead of incurring the costs of installing emissions controls and monitoring and inspection and maintenance (I&M) equipment that would be necessary to comply with PAR 1110.2. Compliance cost calculations are included in Appendix C. Not all operators with non-biogas engines would replace existing ICEs with electric motors based solely on cost considerations. Therefore, SCAQMD staff assumed that operators of 75 percent of the non-biogas engines that may have cost savings (169 engines) would be voluntarily replaced their existing engines with electric motors. It is assumed that 40 percent of these existing engines would be used as emergency backup generators. Twenty percent would use diesel-fueled emergency backup engines. It is assumed that the remaining 40 percent would not need an emergency backup engine.

The conclusions in the NOP/IS still apply to operators of affected engines who choose to replace non-biogas engines with electric motors. Electric motors would likely be placed at or near the location of the existing ICE that would be removed. If the existing engine is used as an emergency backup engine, then it is assumed it would not be moved. It is assumed that if a new diesel emergency engine is installed it would be near the location of the existing ICE engine that would be removed. Since affected non-biogas facilities would already have an existing ICE, it is not expected that the replacement of the ICE with an electric motor and installation of a new emergency backup diesel engine or the use of the existing engine as an emergency backup engine for a new electric motor would change the visual character of the affected facility.

Biogas Engines – New, Retrofit or Replacement Equipment

With the exception of ducting, add-on control systems are expected to be low in profile and height, and not visible to the surrounding area due to existing fencing along the property lines. Existing structures currently within the facilities may buffer the view of such proposed equipment. Systems that require ammonia or urea such as SCR and NOxTech systems may create a more industrial appearance, if located near facility boundaries. The

SCR and NOxTech systems may be as large as the ICEs that they control and may also be visible from outside the facility if placed near the fence line. At digester gas facilities and operating landfills, these systems may not alter the visual character of the area. At closed landfills, these systems may alter the visual character of the area, thus, adversely affecting the visual continuity of the surrounding area.

Therefore, since SCR and NOxTech systems at closed landfills may alter the visual character of the surrounding areas, PAR 1110.2 may create significant adverse aesthetic impacts at biogas facilities due to the installation of retrofit technologies.

Biogas Engines – Replacement Technologies

Biogas facility operators may choose to replace existing ICEs with biogas to LNG facilities, gas turbines, microturbines, fuel cells or boilers. Turbines, microturbines, fuel cells, and boilers are similar in physical characteristics to existing ICE systems. It is unlikely that replacing ICEs with any one of these technologies would modify the visual characteristics of the existing facilities since they are similar in visual character to the ICEs they would be replacing.

The installation of a biogas to LNG facility would require approximately three acres of land based on the existing LNG facility at the Frank R. Bowerman Landfill in Orange County. The biogas facility would consist of process equipment, storage tanks and truck loading racks. Because of the size of the biogas to LNG facility, process equipment and truck loading racks, the equipment and truck loading operations may be visible from outside of the facility. In addition, the process equipment may need additional lighting. Therefore, the installation of a biogas to LNG facility may alter the visual character of the area, thus, adversely affecting the visual continuity of the surrounding area.

Therefore, since SCR and NOxTech systems at closed landfills and LNG facilities may alter the visual character of the surrounding areas, PAR 1110.2 is significant for adverse aesthetic impacts at biogas facilities.

Affected industry representatives have indicated that instead of complying with PAR 1110.2 through retrofitting existing engines, replacing them with new compliant engines, or replacing existing engines with alternative technologies they may simply replace existing engines with flares. Adding a new flare could further degrade the existing visual character of a facility, even though most biogas facilities have an existing flare as an emergency backup system. The potential installation of flares could further degrade the visual character of a biogas facility and, therefore, may create significant adverse aesthetics impacts. To prevent replacement of ICEs with flares, SCAQMD staff has committed to a technology assessment to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacement of biogas ICEs with continuous flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Therefore, the continuous use of new or existing flares ~~are~~ is not expected to be consequence of PAR 1110.2.

Project-Specific Mitigation Measures:

Significant adverse aesthetic impacts are only expected as a result of complying with PAR 1110.2 at biogas facilities. No specific mitigation measures were identified to reduce adverse aesthetic impacts. It is expected that facility operators would place control technology or ICE alternatives away from property boundaries. However, space issues and the location of utilities, location and quality of the biogas source, and piping may dictate the placement of equipment. Equipment may be masked by perimeter walls or landscape vegetation; although, fire prevention and safety issues would take precedence over aesthetic concerns. As a result, there is no guarantee that landscape vegetation would be available as a means of reducing aesthetics impacts.

A technology assessment will be completed in 2010 to evaluate possible control options PAR 1110.2. The technology assessment evaluate whether that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Therefore installation of flares is not considered to be a reasonably foreseeable adverse aesthetics impact.

Since the location and type of control equipment or ICE replacement is unknown for any specific biogas facility and the effectiveness of perimeter walls and landscaping to minimize aesthetics impacts is unknown, it is assumed that aesthetics impacts cannot be mitigated to less than significant.

Remaining Aesthetic Impacts:

Since no project-specific mitigation measures were identified that could eliminate significant adverse aesthetic impacts, aesthetics impacts remain significant.

Cumulative Aesthetic Impacts:

Since project-specific adverse aesthetic impacts are significant, it is possible that cumulative aesthetic impacts from other related facilities in the vicinity of each affected biogas facility that would be subject to PAR 1110.2 could be cumulatively considerable. However, since no biogas facility is within three miles of another biogas facility, potential project-specific aesthetic impacts at more than one affected biogas facility are not perceptible, and, therefore, not considered to be cumulatively considerable as defined by CEQA Guidelines §15064(h)(1). Therefore, PAR 1110.2 is not expected to generate significant adverse cumulative aesthetics impacts.

Cumulative Aesthetic Impact Mitigation:

Because implementing PAR 11110.2 is not expected to create significant adverse cumulative aesthetic impacts, no cumulative impact mitigation measures are required.

Air Quality

Significance Criteria

To determine whether or not air quality impacts from adopting and implementing PAR 1110.2 are significant, impacts will be evaluated and compared to the following criteria. 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.

Table 4-1
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) and Odor Thresholds	
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Hazard Index ≥ 1.0
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402

Ambient Air Quality for Criteria Pollutants	
NO2 1-hour average annual average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.25 ppm (state) 0.053 ppm (federal)
PM10 24-hour average annual geometric average annual arithmetic mean	$10.4\ \mu g/m^3$ (construction) & $2.5\ \mu g/m^3$ (operation) $1.0\ \mu g/m^3$ $20\ \mu g/m^3$
PM2.5 24-hour average	$10.4\ \mu g/m^3$ (construction) & $2.5\ \mu g/m^3$ (operation)
Sulfate 24-hour average	$1\ \mu g/m^3$
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) 9.0 ppm (state/federal)

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea & Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
KEY: lbs/day = pounds per day ppm = parts per million $\mu g/m^3$ = microgram per cubic meter ≥ greater than or equal to

Direct Impacts from Implementing PAR 1110.2 – Operation

PAR 1110.2 would reduce precursor ozone and particulate emissions from gaseous- and liquid-fueled ICEs. Table 4-2 presents the number of ICEs affected by PAR 1110.2. Table 4-3 shows baseline emissions from ICEs derived for the population of ICEs in 2005, using survey information and source test information obtained by SCAQMD staff (see Table 3-5). Table 4-3 shows the year 2005 baseline emission inventories for affected equipment categorized into non-biogas and biogas facilities.

Table 4-2
Inventory of Engines

Category	Diesel	Digester Gas	Digester/ Landfill Gas	Field Gas	Landfill Gas	Natural Gas	Propane	Survey[a] Total	Total[b]
Biogas, BACT, <1000		1						1	1
Biogas, BACT, =>1000		2			14			16	20
Biogas, Non-BACT <1000		12						12	15
Biogas, Non-BACT, =>1000		10	3		12			25	31
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000						3		3	4
Non-Biogas, Non-RECLAIM, BACT, Lean, =>1000						16		16	22
Non-Biogas, Non-RECLAIM, BACT, Rich, <1000				9		238	1	248	336
Non-Biogas, Non-RECLAIM, BACT, Rich, =>1000				2		26		28	38
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000						181		181	245
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, =>1000						5		5	7
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, Diesel	6							6	6
Non-Biogas, RECLAIM, BACT, Lean, Major, Diesel	6							6	6
Non-Biogas, RECLAIM, BACT, Rich, Major				1				1	1
Non-Biogas, RECLAIM, BACT, Rich, Non-Major						16		16	20

Table 4-2 (Continued)
Inventory of Engines

Category	Diesel	Digester Gas	Digester/ Landfill Gas	Field Gas	Landfill Gas	Natural Gas	Propane	Survey[a] Total	Total[b]
Non-Biogas, RECLAIM, Non-BACT, Lean, Major						25		25	31
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major	18			1		10		29	32
Non-Biogas, RECLAIM, Non-BACT, Rich, Major						1		1	1
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major						36		36	44
Survey Total	30	25	3	13	26	557	1	673	1
Total	30	31	4	17	32	744	1		859

a) SCAQMD staff sent surveys out to permit holders that are affected by PAR 1110.2. The information received from these surveys was used to develop the emissions inventory for PAR 1110.2.
b) Total number of engines was estimated by scaling the surveyed engines by the number of engines in the permit database by category (biogas, non-biogas, natural gas, diesel, RECLAIM, non-RECLAIM).

Table 4-3
Estimated Year 2005 Baseline Emissions Inventory
Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	7,336	44,688	1,611	87	741
Biogas	66	1,859	9,555	882	464	136
Total	859	9,195	54,243	2,493	551	877

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-4 shows the estimated emission reductions by year assuming that all affected engines can comply with the emission concentration requirements in PAR 1110.2 and taking into account better monitoring. The estimated emission reductions show emission reductions from the baseline year of 2005. The emission reductions do not show the effects of potential secondary quality impacts, which are analyzed later in this document.

Table 4-4
Estimated Emission Reductions by Year from the Baseline Year 2005 from Implementing PAR 1110.2

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM* lb/day
2008	~~204~~ 199	~~379~~ 346	~~35~~ 26	~~8~~ 7	~~5~~ 5
2009	~~2,359~~ 2,354	~~30,936~~ 30,903	~~646~~ 637	~~8~~ 7	~~5~~ 5
2009	~~2,374~~ 2,369	~~31,709~~ 31,676	~~658~~ 649	~~8~~ 7	~~5~~ 5
2010	~~2,748~~ 2,743	~~35,929~~ 35,896	~~1,127~~ 1,118	~~10~~ 9	~~8~~ 8
2011	~~3,093~~ 3,088	~~38,845~~ 38,752	~~1,372~~ 1,165	~~0~~ 9	~~0~~ 8
2012	4,335	38,845	1,372	0	0

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-5 shows the total emission reductions by the year 2012 for affected equipment, which is the year of full compliance with PAR 1110.2, categorized into non-biogas and biogas facilities.

Table 4-5
Estimated Emission Reductions in Year 2012 upon Full Implementation of PAR 1110.2 Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	2,948	37,383	1,045	0	0
Biogas	66	1,387	1,463	327	0	0
Total	859	4,335	38,845	1,372	0	0

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-6 shows the estimated emission inventories by year from ICEs complying with PAR 1110.2. All emission reductions for the year 2008 are assumed to result from biogas facility operators complying with the provision in subparagraph (d)(1)(C) regarding the operation of engines on 90 percent or more of landfill or digester gas. The emission inventory estimates assume that all affected ICEs will be able to comply with the proposed emission concentration and includes the effects of the enhanced monitoring and enforcement requirements. This analysis does not pre-judge the results of the future technology assessment in 2010, which may conclude that additional time may be necessary for compliance, or different emission concentration limits are appropriate. The declining emission inventories in Table 4-6 also do not take into consideration potential secondary air quality impacts resulting from PAR 1110.2, which are analyzed later in this document.

Table 4-6
Estimated Remaining Emission by Year
Resulting from Implementing PAR 1110.2

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM* lb/day
2008	~~9,195~~ 9,200	~~54,243~~ 54,276	~~2,493~~ 2,502	~~551~~ 552	~~877~~ 877
2009	~~8,991~~ 8,996	~~53,865~~ 53,898	~~2,458~~ 2,467	~~544~~ 545	~~871~~ 871
2009	~~6,836~~ 6,841	~~23,307~~ 23,340	~~1,846~~ 1,855	~~544~~ 545	~~871~~ 871
2010	~~6,820~~ 6,452	~~22,534~~ 18,347	~~1,834~~ 1,375	~~544~~ 543	~~871~~ 869
2011	~~6,447~~ 6,452	~~15,458~~ 18,347	~~1,319~~ 1,375	~~542~~ 543	~~869~~ 869
2012	4860	1,5398	1,121	551	877

* Combustion emissions where developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions are 98 to 99 percent PM2.5).

Table 4-7 shows the year 2012 emission inventories for affected equipment, which is the year of full compliance with PAR 1110.2, categorized into non-biogas and biogas facilities.

Table 4-7
Estimated Year 2012 Emissions Remaining upon Full Implementation of PAR 1110.2
Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	4,388	7,305	566	87	741
Biogas	66	472	8,092	555	464	136
Total	859	4,860	15,398	1,121	551	877

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Calculating Emissions – Non-biogas Facilities

To calculate the effects of PAR 1110.2 for non-biogas engines, it was assumed that affected facility operators would install similar types of monitoring and control equipment at each facility. PAR 1110.2 specifies that CEMS, air-to-fuel ratio controllers (ATFRC), and CO analyzers would be needed. Lean burn non-RECLAIM, rich burn non-RECLAIM, and rich burn RECLAIM engines are already controlled by oxidation catalysts. Currently, the only uncontrolled non-biogas engines are lean burn RECLAIM engines. To comply with PAR 1110.2, it is expected that operators of existing uncontrolled, lean burn, RECLAIM non-biogas engines would control VOC and CO emissions through the use of an oxidation catalyst. The existing uncontrolled, lean burn, RECLAIM non-biogas engines are exempt from PAR 1110.2 NOx requirements, since NOx from these facilities is subject to RECLAIM NOx control requirements.

Emission Assumptions for Existing Equipment

Rich-burn Engines: For non-RECLAIM rich-burn engines that were originally permitted at BACT emission levels and that have NOx CEMS, it was assumed that NOx emissions are maintained on average at 80 percent of the existing Rule 1110.2 NOx emissions limit. For most rich-burn engines, baseline NOx and CO emissions were developed from NOx and CO limits multiplied by factors that are based on SCAQMD compliance test results (see Table 3-4). SCAQMD compliance tests showed that for engines without CEMS, the average ratio of measured NOx to the NOx limit is 5.19 for BACT engines (NOx limit in 8 to 23 ppm range) and 2.12 for non-BACT engines (NOx limit in 36 to 59 ppm range). Although compliance testing did not include VOC data, source test data reported in the engine survey showed that VOC levels tend to correlate to roughly the square root of the CO level.

For RECLAIM major sources, it was assumed that the NOx level is at the apparent "limit," calculated from Annual Emissions Report data. For non-BACT rich-burn engines in RECLAIM, NOx concentrations are often above the range of the SCAQMD compliance data (none tested in this category), and it is assumed that baseline NOx for non-major sources (no CEMS) in this group is maintained, on average, at the NOx limit.

Lean-burn Engines: For non-BACT lean-burn RECLAM engines, non-CEMS NOx emissions were assumed to be maintained at the reported limit or apparent limit that was calculated based on annual emission reporting. CO and VOC emissions were assumed to be 10 percent over source test results on average.

For BACT, non-RECLAIM lean-burn engines, non-CEMS NOx emissions were assumed to be 1.8 times the NOx limit based on SCAQMD compliance test results (see Table 3-4). CO and VOC emissions were assumed 10 percent above average source test results.

Emission Reduction Assumptions to Comply with PAR 1110.2

The analysis of emissions reductions from non-biogas engines to comply with PAR 1110.2 was based on the type of engine, emission limits and compliance expectations as explained in the preceding subsection. The analysis was based on a total population of 793 non-biogas engines.

For the CEQA analysis, SCAQMD staff performed a cost analysis for existing non-biogas engines comparing various cost of compliance options to the cost of complying with PAR 1110.2, i.e., the costs of installing emissions control equipment, monitoring equipment, I&M, etc., to the cost replacing existing ICEs with electric motors (calculations are included in Appendix C). The analysis indicated that the cost of replacing existing specific categories of non-biogas ICEs (225 non-biogas ICEs out of the total 793 non-biogas engines) with electric motors would be less than the cost of complying with PAR 1110.2 requirements, i.e., the cost of retrofitting the same engines with emissions control equipment, monitoring equipment I&M, etc. Table 4-8 shows the engine categories for the existing 225 engines where the cost of replacing existing ICES with electric motors would be less costly than complying with PAR 11102. However, not all operators with non-biogas engines in the engine categories shown in Table 4-8 are expected to replace existing non-biogas ICEs with electric motors based solely on cost considerations. Therefore, SCAQMD staff assumed that operators of 75 percent of the engines shown in Table 4-8 (169 engines) would choose electrification as their compliance option.

Table 4-8
Non-biogas ICE Categories Where Replacing Existing ICEs with Electric Motors Would be Less Costly Compared to Complying with PAR 1110.2 Requirements

Engine Use	Number of Engines Surveyed	Total Engines	Assumed No. of ICEs Replaced with Electric Motors
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000	2	3	2
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000	126	170	128
Non-Biogas, RECLAIM, BACT, Rich, Non-Major	6	7	5
Non-Biogas, RECLAIM, Non-BACT, Lean, Major	15	19	14
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major	7	9	7
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major	14	17	13
Total	170	225	169

It was assumed that operators who install electric motors on 40 percent of the engines shown in Table 4-8 would keep their existing ICEs as emergency backup generators. It was further assumed that operators who install electric motors on 20 percent of the engines shown in Table 4-8 would purchase new diesel ICEs for emergency backup generators. Finally operators of the remaining 40 percent were assumed not to need emergency backup generators because of the nature of their operations. Emission reductions from replacing 169 existing engines with electric motors are presented in Table 4-9. Secondary emissions from the diesel emergency backup generators are analyzed later in this section.

Table 4-9
Emissions Reductions from the Compliance Option of Replacing Existing Non-Biogas ICEs with Electric Motors

NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
1,044	2,507	175	14.3	87.9	107,276

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
- This table presents only the emission reductions from replacing the non-biogas ICEs with electric motors. It does not include the secondary emissions from power plants or emergency engines.

It was assumed that operators of all 624 remaining non-biogas engines would comply with the requirements of PAR 1110.2 by installing appropriate control technologies. Total emission reductions by 2012 for non-biogas ICEs are shown in Table 4-7.

Calculating Emissions – Biogas Facilities

Biogas facilities can be categorized as either landfill gas facilities or digester gas facilities. Landfill gas facilities collect biogas from landfills and combust the biogas to generate electricity. Digester gas facilities collect biogas from water treatment facilities or compost facilities and combust the biogas to generate electricity or power compressors and pumps.

Emission Assumptions for Existing Equipment

Biogas baseline emissions are based on NOx limits, landfill gas VOC limits (40 ppm as methane at 15 percent O_2), average VOC source test results for digester gas engines based on the survey data, and average CO source test results based on the survey data. In all cases except for CEMS-monitored NOx engines, baseline emissions are assumed to be, on average, 10 percent higher than the above limits or source test results.

Emission Reduction Assumptions to Comply with PAR 1110.2

It is assumed that operators of biogas systems will comply with PAR 1110.2 by controlling emissions from ICEs with SCR or NOxTech systems or replace the ICE with an alternative technology that would not be regulated by PAR 1110.2, such as, boilers, gas turbines, microturbines, fuel cells or biogas to LNG facilities[25]. Emission reductions from ICEs controlled by SCR or NOxTech systems were estimated based on PAR 1110.2 limits. The emission reductions anticipated for PAR 1110.2 are based on the assumption that operators of biogas facilities can comply with PAR 1110.2 by installing control equipment onto their equipment. However, based on comments received by the regulated industry, operators may replace biogas engines with alternative technologies and, thus, would no longer be subject to PAR 1110.2. If biogas operators choose to replace ICEs with alternative technologies (gas turbines, microturbines, LNG plants, etc.), the alternative technologies would be subject to other regulatory requirements such as Regulation XIII.

To account for the possibility that affected operators may install alternative technologies; staff has calculated the potential emission reduction effects if all affected biogas engines are replaced with alternative technologies. Table 4-10 shows the emission factors used to calculate the emission reduction effects for ICEs, boilers, gas turbines and microturbines. To address concerns of commenters, which have not been verified, SCAQMD staff has committed to a technology assessment in 2010. If the technology assessment shows the potential for flaring, then staff will return to the Governing Board with a proposal addressing any new significant adverse impacts. Facility operators who replace ICEs with fuel cells would not generate any appreciable emissions, so emissions would essentially be zero. The analysis assumes that facility operators who replace ICEs with biogas to LNG facilities would generate emissions from boilers used to produce heat for the process and would use electric motors for electricity.

[25] ICE alternative technologies are included here based on comments received at PAR 1110.2 working group meetings. Further, LNG derived from biogas would be pretreated for sale offsite or used onsite as natural gas.

Table 4-10
Emission Factors (lb/MMBtu) for Biogas Facility Control Options

Pollutant	ICE	Boiler	Gas Turbine	Microturbine
NOx	0.127	0.03	0.084	0.012
CO	0.644	0.0041	0.139	0.047
VOC	0.041	0.0034	0.0048	0.012
PM	0.013	0.0092	0.023	0.0037

NOx, CO, VOC and PM emissions were based on averages of source test data in AQMD files.
SOx was estimated from the fuel digester gas - 40 ppm as H2S (R431.1); landfill gas - 150 ppm as H2S (R431.1
CO2 was estimated from the amount of carbon in the fuel and the amount of CO emitted (see Appendix C).
PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-11 shows the year 2005 baseline emission inventory for biogas engines and the year 2012 remaining emission inventory, i.e., the year of full compliance with PAR 1110.2 for the various compliance options – add-on control equipment or the use of ICE replacement technology such as gas turbines, microturbines, LNG plants or a mixture of LNG plants and turbines or microturbines (assumed gas turbine or microturbines at digester facilities because of possible facility size restrictions and LNG plants at landfill gas facilities).

Table 4-11
Year 2012 Remaining Emissions for Various Biogas Facility Control Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day
Year 2005 Baseline	1,859	9,555	882	464	136
ICEs with SCR and Ox Cat or other	472	8,092	555	464	136
Replace with Gas Turbines	1,148	1,900	66	464	314
Replace with Microturbines	164	642	164	464	51
Replace with LNG Plants	110	15	13	101	34
Replace LFG w LNG, DG w Turbines	513	784	32	136	142
Replace LFG w LNG, DG w Microturbines	109	269	72	136	34

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5. LFG is landfill gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-12 shows the year 2012 emission reductions from the year 2005 baseline for the various control options. Although control options other than installing control equipment on existing biogas ICEs may have greater emission reduction benefits, the SCAQMD is not taking credit for emission reductions from alternative control options.

Table 4-12
Estimated Criteria Emissions/Reductions in 2012 from Year 2005 Baseline for Biogas Facility Control Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day
ICEs with SCR and Ox Cat or other	(1,387)	(1,463)	(327)	0	0
Replace with Gas Turbines	(710)	(7,655)	(816)	0	179
Replace with Microturbines	(1,695)	(8,913)	(718)	0	(85)
Replace with LNG Plants	(1,748)	(9,540)	(869)	(363)	(102)
Replace LFG w LNG, DG w Turbines	(1,346)	(8,771)	(850)	(328)	6.0
Replace LFG w LNG, DG w Microturbines	(1,749)	(9,286)	(810)	(328)	(102)

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). Numbers in parentheses represent emission reductions. PM includes both PM10 and PM2.5. PM10 includes PM2.5. LFG is landfill gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

<u>Secondary Air Quality Impacts – Operation</u>

To reduce emissions from affected ICEs, it is expected that facility operators would install appropriate air pollution control equipment. Alternatively, operators could replace ICEs with alternative technologies. The following sections evaluate potential secondary adverse air quality impacts from the operation of control equipment, emergency backup power systems that may need to be installed, or alternative ICE replacement technologies. The analysis of secondary adverse impacts is completed for CEQA purposes, using conservative assumptions. Facility operators may not choose compliance options as conservative as presented in this analysis.

<u>Secondary Air Quality Impacts – Power Plants</u>

Facility operators who replace non-biogas ICEs with electric motors and facility operators who replace biogas ICEs with alternative technologies may need additional electricity from the electricity grid than would otherwise be the case if they installed air pollution control equipment on existing affected ICEs. For example, additional electricity may be necessary for biogas ICE alternative technologies because gas turbines and microturbines are less efficient than ICEs. Facility operators who replace biogas ICEs with biogas-to-LNG plants would also need additional electricity to run the plants. Staff assumed that the electricity supplied to the grid for this additional energy would be supplied by new natural gas power plants within the district. SCAQMD staff assumed that grid power replacing engine power or work would be produced in the following ratio: 80 percent by natural gas plants and 20 percent from renewable sources, consistent with California's Renewable Portfolio Standard Program. The average fossil plant efficiency was assumed to be 36 percent based on the USEPA Acid Rain data. Emissions from power plants were derived from those in the SCAQMD annual emission reporting program. NOx and SOx emissions were not included because these emissions are capped by the SCAQMD's RECLAIM (REgional CLean Air Incentives Market) program. Tables 4-13 and 4-14 show estimated emissions from power plants supplying affected non-biogas and biogas facilities, respectively, with additional electricity. The non-biogas facility values assume facility operators would elect to replace 169 engines with electric motors as a less costly compliance option (see Appendix C).

Table 4-13
Secondary Emission Increases from Power Plants Supplying Affected Non-Biogas Facilities with Additional Electricity

Description	CO, lb/day	VOC, lb/day	PM, lb/day
2009 requirements	12.2	1.0	1.3
2010 requirements	80.2	6.5	8.4
2011 requirements	126	10.2	26.4

- Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
- CO2 and VOC emissions were based on CARB emission factors for modern central station power plants (CO = 0.1 lb/MW-hr and VOC = 0.02 lb/MW-hr.
- NOx and SOx emissions are assumed to be capped by RECLAIM.

Table 4-14
Secondary Emission Increases in 2012[a] from Power Plants Supplying Affected Biogas Facilities with Additional Electricity[b]

Description	CO, lb/day	VOC, lb/day	PM,[c] lb/day
ICEs with SCR	1.3	0.10	0.13
Replace with Gas Turbines	51	4.1	5.3
Replace with Microturbines	83	6.7	8.6
Replace LFG w LNG, DG w Turbines	292	24	31
Replace LFG w LNG, DG w Microturbines	305	25	32

a) SCAQMD staff assumed that operational emission from PAR 1110.2 concentration requirements at biogas facilities would begin in 2012.
b) NOx and SOx emissions are capped by the RELCLAIM program; therefore, it was assumed that there would be no change in NOx or SOx emissions. LFG is landfill gas. DG is digester gas.
c) Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
d) The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-15 shows total secondary power plant emission increases in the year 2012 that would be generated to supply the electricity needs for both non-biogas ICE replacement electric motors and all possible biogas compliance options.

Table 4-15
Total Secondary Emission Increases in 2012[a] from Power Plants Supplying Affected Biogas and Non-Biogas Facilities with Additional Electricity[b]

Description	CO, lb/day	VOC, lb/day	PM,[c] lb/day
ICEs with SCR	127	10.3	26.5
Replace with Gas Turbines	177	14.2	31.6
Replace with Microturbines	209	16.8	35.0
Replace LFG w LNG, DG w Turbines	418	33.7	56.9
Replace LFG w LNG, DG w Microturbines	431	34.8	58.3

a) SCAQMD staff assumed that operational emission from PAR 1110.2 concentration requirements at biogas facilities would begin in 2012.
b) NOx and SOx emissions are capped by the RELCLAIM program; therefore, it was assumed that there would be no change in NOx or SOx emissions. LFG is landfill gas. DG is digester gas.
c) Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
d) The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Secondary Air Quality Impacts – Ammonia Slip Emissions

Facility operators may install SCR or NOxTech control systems. Both systems use either urea or aqueous ammonia to control NOx emissions. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. To ensure maximum reduction of NOx emissions, slightly more than a one-to-one molar ratio of ammonia to NOx may be injected into the exhaust, resulting in unreacted ammonia which escapes or "slips" from the stack and is commonly referred to as 'ammonia slip.'

Under normal operating and permitted conditions, ammonia slip is approximately five to 10 ppm. Staff estimates approximately 0.44 pounds of ammonia per pound of NOx reduced would be required to reduce NOx and that 40 percent of the excess ammonia would be injected to produce a slip 10 ppm. Approximately 3,775 pounds of 19 percent ammonia or 1,266 pounds of urea would be used per day to control NOx emissions. Based on this emission factor 205 pounds of ammonia would be emitted as slip per day.

There is a potential for a slight increase in the secondary formation of particulate emissions resulting from the use of ammonia in the SCR in the presence of sulfur compounds which are present in small quantities in natural gas. While most of the fuel sulfur is converted to SO2, about 1.5 percent is converted to SO3 in the presence of the SCR catalyst. SO3 reacts with ammonia in the presence of water from the exhaust and forms ammonium sulfate and ammonia bisulfate, which is a very fine solid. Public Utility Commission-grade low sulfur natural gas contains no more than 0.75 grains/100 standard cubic feet of gas. This is roughly equivalent to 10 parts per million (ppm). Since only a fraction of the sulfur will contribute to formation of particulate, insignificant quantities of particulate will form as a result of the installation of the SCR system.

Secondary Air Quality Impacts – Emergency Backup Engines

For some types of operations, operators replacing existing natural gas engines with electric motors would also need to install emergency backup engines to provide power for necessary operations during power failures. Public comments were received on the NOP/IS and Preliminary Staff Report stating that the costs for air pollution control and monitoring equipment would cause affected facility operators to replace some existing natural gas engines with electric motors and purchase diesel emergency engines. Subsequent to the release of the NOP/IS and Preliminary Staff Report, exceptions added to PAR 1110.2 for the use of two-stroke engines, low usage engines, engines less than 500 bhp and CEMS sharing have eliminated the need for monitoring and control technology on some engines of concern to commenters. Consequently, the costs of installing control equipment, monitoring equipment, etc., on two-stroke engines, low usage engines, engines less than 500 bhp, etc., are not expected to result in operators replacing these engines with electric motors. The following two subsections analyze potential adverse secondary emissions from operating emergency back-up engines at both non-biogas and biogas facilities, respectively.

Non-Biogas Facilities

Based on a cost analysis (see Appendix C), SCAQMD staff identified operators of 225 non-biogas engines who would incur lower compliance costs by replacing their existing ICEs with electric motors instead of incurring the costs of installing emissions control and monitoring equipment, I&M, that would be required by PAR 1110.2. Not all operators with non-biogas engines in these engine categories would replace existing ICEs with electric motors based solely on lower compliance costs over ten years. Therefore, SCAQMD staff assumed that operators of 75 percent of non-biogas engines (169 engines) in the specified engine categories (see Table 4-8) would choose the alternative compliance option of replacing existing ICEs with electric motors as the most cost-effective compliance option. It is assumed that: operators of 40 percent of these engines would use the existing engines as emergency generators; operators of 20 percent of these engines would use diesel-fueled emergency engines; and operators of the remaining 40 percent of are not assumed to need an emergency engine.

The analysis further assumed that diesel emergency backup engines would operate 50 hours per year for engine testing (the maximum testing allowed per year pursuant to Rule 1470). For this analysis, it was assumed that the brake horsepower rating of the emergency backup engines installed would be equivalent to the brake horsepower rating of the existing natural gas engine replaced divided by 0.97 to account for electric motor efficiency. Diesel emission factors from 40CFR, Part 89 - Control of Emissions from New and In-Use Compression-Ignition Engines were used.

Finally, it was assumed that the emission factors for the existing natural gas engines would be the same emission factors when they are used as emergency backup. Criteria emissions from emergency engines at non-biogas facilities are presented in Tables 4-16 through 4-18.

Table 4-16
Criteria Emissions from Diesel Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	10.2	6.8	1.14	0.014	0.39	0.39
2010	120	78.8	13.3	0.16	4.5	4.5
2011	159	118	16.9	0.24	6.6	6.6

Table 4-17
Criteria Emissions from Natural Gas Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	11.3	5.8	2.1	0.039	0.27	0.27
2010	55.2	134.1	28.9	0.50	3.4	3.4
2011	68.7	262	31.0	0.61	4.2	4.2

Table 4-18
Total Criteria Emissions from Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	21.6	12.6	3.2	0.053	0.65	0.65
2010	175	213	42.3	0.67	8.0	8.0
2011	228	379	47.9	0.85	10.8	10.8

Includes emission from both biogas and non-biogas emergency engines.

Biogas Facilities

Operators of biogas facilities who replace existing ICEs with an alternate technology may also require emergency backup ICEs to run compressors and pumps in the event of a power outage. It was assumed that landfill gas facilities would not need to run during emergency loss of power from the electrical grid, since it is believed that landfill gas facilities flare landfill gas during power loss. Digester gas facilities may need to continue to run if power is lost from the electrical grid, since digester gas facilities would need to continually operate pumps. Based on these assumptions and the survey information, it is likely that 33 digester gas facilities may need diesel emergency generators. It was assumed that operators of 80 percent (26 facilities) of the digester gas facilities that need emergency backup engines would use their existing natural gas engines for emergency backup power. Operators of the remaining 20 percent (seven facilities) were assumed to use diesel emergency generators.

The same assumptions used for non-biogas emergency engines were used to develop emissions for digester emergency generators. It was assumed that the diesel emergency engines would be sized for the increased grid dependency (power produced by ICE less power produced by alternative technology or power required to compensate for the pressure drop of add-on control). For the case of blowers replaced by alternative technology, it was assumed that the emergency generator would be sized to replace the shaft work produced by the ICEs. Emergency engines were assumed to operate 50 hours per year. Diesel emission factors from 40CFR, Part 89 - Control of Emissions from New and In-Use Compression-Ignition Engines were used. If existing engines are used as emergency generators for ICE alternative technology, then it was assumed that the emergency generator emissions would be the same as the existing engines. .

Facility operators who install add-on control technology to existing ICEs are not expected to need new emergency backup engines to comply with PAR 1110.2. It is expected that operators would use existing emergency engines or continue to operator without emergency power. If these operators were to install emergency engines, it would be for reasons other than complying with PAR 1110.2.

Based on the above assumptions, criteria emissions from diesel fueled emergency backup engines at biogas facilities are presented in Tables 4-19 through 4-21. Table 4-19 shows emissions from emergency diesel backup engines, Table 4-20 shows emissions from natural gas-fueled emergency backup engines, and Table 4-21 shows total emissions from both diesel fueled- and natural gas-fueled emergency backup engines.

Table 4-19
Criteria Emissions from Diesel-Fueled
Emergency Backup Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	9.4	7.5	0.96	0.01	0.42	0.41
Replace with Microturbines	22.6	15.7	2.46	0.02	0.89	0.87
Replace LFG w LNG, DG w Turbines	9.4	7.5	0.96	0.01	0.42	0.41
Replace LFG w LNG, DG w Microturbines	22.6	15.7	2.46	0.02	0.89	0.87

- PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-20
Criteria Emissions from Natural Gas-Fueled
Emergency Backup Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	14.5	70.4	6.4	0.28	1.9	1.9
Replace with Microturbines	20.6	99.6	9.1	0.40	2.8	2.7
Replace LFG w LNG, DG w Turbines	14.5	70.4	6.4	0.28	1.9	1.9
Replace LFG w LNG, DG w Microturbines	20.6	99.6	9.1	0.40	2.8	2.7

PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.

Table 4-21
Total Criteria Emissions from Diesel-fueled and Natural Gas-fueled Emergency Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	24.0	78.0	7.4	0.30	2.4	2.3
Replace with Microturbines	43.2	115.3	11.5	0.42	3.6	3.6
Replace LFG w LNG, DG w Turbines	23.3	77.4	7.3	0.30	2.3	2.3
Replace LFG w LNG, DG w Microturbines	42.2	114.4	11.5	0.42	3.6	3.6

- PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Secondary Air Quality Impacts – Spent Catalyst Disposal Trips

Over time, the effectiveness of catalysts used in both SCR and oxidation air pollution control equipment lose their effectiveness primarily due to clogging of the catalyst pores. Because oxidation catalysts use metals that have substantial economic value, depending on the size of the control unit, they may be recycled and reused. Ceramic-based SCR catalysts can be crushed and reused in concrete. Metal-based SCR catalysts and some ceramic-based catalysts, if not recycled, would be crushed, encased in concrete and eventually disposed of in a Class II landfill or a Class III landfill that is fitted with liners. A detailed discussion on the disposal of spent catalysis can be found in the Solid/Hazardous Waste Impact Section below. While there are several Class II and Class III landfills in the district, there are only three Class I facilities in California, which are located outside of the district. The three Class I facilities are Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA and Clean Harbors Westmorland in Westemorland, CA. Since Class I facilities are further away, and therefore require more travel, as a worst-case, it is assumed that all catalyst waste is disposed of at one of the Class I facilities.

As a worst-case analysis, SCAQMD staff assumed that catalyst would be changed out every three years. Because biogas facility operators are not expected to install add-on controls or replace ICEs with alternative technology until after the technology assessment in 2010, SCAQMD staff does not expect the maximum number of new and replacement catalysts trips to begin until 2014. Based on the SCAQMD engine survey operators of approximately 28 biogas facilities could potentially install SCR and oxidation catalyst systems and operators of seven non-biogas facilities would need to install oxidation catalyst. Based on the size of the largest SCR and oxidation catalysts, it is expected that three truck trips would be necessary to dispose of the catalysts from the largest affected facilities. None of the operators at the 45 facilities with existing catalysts who would need to upgrade their catalysts to comply with PAR 1110.2 would require more than one truck trip for the entire catalyst bed replacement. Since the facilities that require upgrades already dispose of catalysts, there is no expected change in disposal truck trips (i.e., no additional truck trips). Given that catalysts will be installed at different times and are subject to different operating parameters, it is unlikely that spent catalysts would all be replaced on the same day. As a result, it was conservatively assumed that there would be up to two large spent catalyst units disposed of on a single day. Therefore, a maximum of six additional truck trips would occur on any one day as a result of implementing PAR 1110.2 (three trucks per facility from two facilities). There are three possible Class I disposal sites in California: Kettleman City (178 miles from Los Angeles), Buttonwillow (133 miles from Los Angeles), and Westmorland (192 miles from Los Angeles). The intermediate distance, 178 miles per one-way trip, was chosen for this analysis. Spent catalyst haul truck emissions are shown in the first line of Tables 4-22 through 4-26.

Note that Tables 4-22 through 4-26 also show other types of secondary air quality impacts from various types of truck trips based on different compliance options for biogas engines. The information shown in Tables 4-22 through 4-26 assumes that operators 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines not exempted by the low-use exemption, a total of 264 engines, would comply with PAR 1110.2. Analysis details for the information presented in Tables 4-22 through 4-26 can be found in Appendix C.

Table 4-22
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas and Biogas SCR and Oxidation Catalyst Compliance Options Only

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.9	4.8
New Catalyst Delivery Truck	17.0	5.2	1.34	0.014	0.83	0.80
Spent Carbon Haul Truck	5.66	1.74	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.66	1.74	0.45	0.0048	0.28	0.27
Source Test	5.66	1.74	0.45	0.0048	0.28	0.27
Ammonia Delivery	0.00	0.00	0.00	0.0000	0.00	0.00
Diesel Delivery	5.66	1.74	0.45	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-23
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Compliance Option with Biogas Gas Turbine Compliance Option

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.9	4.8
New Catalyst Delivery Truck	17.0	5.2	1.3	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.4	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.4	0.0048	0.28	0.27
Source Test	5.7	1.7	0.4	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.4	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-24
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Biogas Microturbine Compliance Option

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.93	4.8
New Catalyst Delivery Truck	17.0	5.2	1.3	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.45	0.0048	0.28	0.27
Source Test	5.7	1.7	0.45	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.45	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-25
Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Biogas Gas Turbine at Digester Facilities and LNG Plants for Landfill Gas Facility Compliance Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	7.97	0.085	4.93	4.8
New Catalyst Delivery Truck	17.0	5.2	1.34	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.45	0.0048	0.28	0.27
Source Test	5.7	1.7	0.448	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.448	0.0048	0.28	0.27
LNG Haul Truck	125	38.2	9.8	0.105	6.10	5.9
Total	265	81.2	20.9	0.22	13.0	12.5

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-26
Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Non-Biogas and Microturbine at Digester Facilities and LNG Plants for Landfill Gas Facility Compliance Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.0846	4.9	4.8
New Catalyst Delivery Truck	17.0	5.21	1.34	0.0143	0.83	0.80
Spent Carbon Haul Truck	5.7	1.74	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.74	0.45	0.0048	0.28	0.27
Source Test	5.7	1.74	0.45	0.0048	0.28	0.27
Diesel Delivery	5.7	1.74	0.45	0.0048	0.28	0.27
LNG Haul Truck	125	38.2	9.8	0.105	6.1	5.88
Total	265	81.2	20.9	0.22	13.0	12.5

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Secondary Air Quality Impacts – Spent Activated Carbon Disposal Trips

Activated carbon is typically used in pre-treatment systems for biogas facilities where influent streams have high sulfur content that could potential foul or plug control technology. Digester gas may have high siloxane, hydrogen sulfide (H2S) and VOC content, that if not removed may contaminate catalysis. Landfill facilities may not require pretreatment systems.

Based on survey responses there are approximately 28 biogas facilities. Of the 28 facilities, there are approximately 12 landfill facilities in the district, approximately 15 digester gas facilities, one facility that handles both landfill and digester gas. Based on discussions with a contractor, it is believed that activated carbon used in pre-treatment systems would be replaced every three months. However, even though all 28 biogas facilities are expected to need pre-treatment systems, SCAQMD staff assumed that catalyst would be replaced at two facilities on any one day. Based upon available information, SCAQMD staff estimated that two truck trips would be required per facility. One trip to collect and dispose of spent activated catalyst and a second trip to deliver new catalyst. Activated carbon is typically regenerated and reused in treatment systems. Eventually spent activated carbon residues in the form of ash are disposed of in local landfills. Because affected facilities are located throughout the district and the locations of the carbon suppliers and landfill where spent carbon residues would be disposed of are unknown, the analysis assumed a haul trip distance of 30 miles per one-way trip.

Secondary operational criteria emissions from truck trips to supply activated carbon and dispose of carbon residues are presented in Tables 4-22 through 4-26. Detailed calculations are presented in Appendix C.

Secondary Air Quality Impacts – Ammonia/Urea Delivery Trips

Ammonia use would be required for facilities where operators install either SCR or NSCR systems, primarily to control NOx emissions. The number of delivery trips was estimated from the amount of ammonia that would be required to reduce NOx concentrations to the PAR 1110.2 limit of 11 ppm of NOx. To reduce hazard impact (see Hazards/Hazardous Material below), SCAQMD policy prohibits the use of new anhydrous ammonia control systems for air pollution control, restricting ammonia for new control systems to 19 percent aqueous ammonia. Therefore, based on SCAQMD policy regarding ammonia used in air pollution control systems, existing engine horsepower, and the assumption that operators of 28 biogas facilities, SCAQMD staff conservatively assumed that up to 38 ammonia deliver truck trips could occur per year, no more than one ammonia delivery truck trip would occur on any single day. Because the actual ammonia supplier for each facility is unknown, staff assumed the trip length for ammonia delivery truck trips were 30 miles per one-way trip.

Secondary operational criteria emissions from ammonia delivery truck trips are presented in Table 4-22. The analysis assumes that alternative biogas compliance options would not require ammonia to comply with PAR 1110.2 NOx emission concentrations because these compliance options would no longer be subject to PAR 1110.2 requirements. Detailed calculations are presented in Appendix C.

Secondary Air Quality Impacts – LNG Delivery Trips

Operators at biogas facilities who choose the compliance option of replacing existing ICEs with LNG plants could use the LNG onsite as a combustion fuel or export it offsite for use as a vehicle fuel, for example. LNG produced at biogas facilities would most likely be exported offsite using cryogenic tanker trucks. The LNG plant at the Bowerman Landfill in Orange County was used as a model for evaluating secondary air quality impacts from LNG truck deliveries. Based on the quality and amount of natural gas generated at the Bowerman Landfill, operators are expected to use 10,000-gallon cryogenic tanker trucks to export LNG, with one LNG truck delivery trip occurring every other day. Assuming a similar quality of landfill gas will be generated at affected biogas facilities as is generated at the Bowerman Landfill and assuming the use of 10,000-gallon cryogenic tanker trucks, it is expected that approximately 33 LNG delivery truck trips would occur on any single day if operators of all 22 biogas facilities install LNG plants. The estimate of 22 biogas facilities is conservative since only 12 of the biogas facilities are landfill gas facilities. Because the actual LNG customer for each facility is unknown, staff assumed the trip length for LNG delivery truck trips were 40 miles per one-way trip.

Secondary operational criteria emissions from operating travel activities are presented in Tables 4-22 and 4-26. Detailed calculations are presented in Appendix B.

Total Operational Criteria Emissions from PAR 1110.2

Tables 4-27 through 4-31 show the year 2005 baseline inventory for all existing equipment and the remaining emission inventory for the compliance years shown, based on emission reductions anticipated for each compliance year. The information shown in Tables 4-27 through 4-31 assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines, a total of 624 engines would comply with PAR 1110.2. Table 4-27 shows the remaining emissions by compliance year for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-28 shows the remaining emissions by compliance year for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-29 shows the remaining emissions by compliance year for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-30 shows the remaining emissions by compliance year for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-31 shows the remaining emissions by compliance year for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Tables take into account all secondary adverse operational air quality impacts described in the above subsections. Finally, the remaining inventory for the year 2014 for each of the scenarios shown in Tables 4-27 through 4-31 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life.

Table 4-27
Total Criteria Emissions from Operation with Non-biogas Facilities and SCR at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,345~~ 5,350	~~13,475~~ 13,508	~~1,207~~ 1,216	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	4,125	13,423	1,011	538	830	829
2014	4,184	13,441	1,015	538	833	831

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-28
Total Criteria Emissions from Operation with Non-biogas Facilities and Gas Turbines at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	4,825	7,357	533	538	1,016	1,014
2014	4,884	7,375	537	538	1,019	1,017

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-29
Total Criteria Emissions from Operation with Non-biogas Facilities and Microturbines at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	3,860	6,169	638	538	757	756
2014	3,919	6,187	643	538	760	758

Table 4-30
Total Criteria Emissions from Operation with Non-biogas Facilities and Gas Turbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,440~~ 6,445	~~23,215~~ 23,248	~~1,814~~ 1,823	~~543~~ 544	~~860~~ 861	~~858~~ 859
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822
2012	4,254	6,503	523	211	872	870
2014	4,373	6,540	533	211	878	876

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-31
Total Criteria Emissions from Operation with Non-biogas Facilities and Microturbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822
2012	3,870	6,038	569	211	767	765
2014	3,989	6,075	578	211	773	771

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Construction Air Quality Impacts

Installing control and monitoring equipment to comply with PAR 1110.2 emission concentrations and monitoring provisions or replacing existing ICEs with alternative technologies is expected to require construction activities. The following subsections analyze construction air quality impacts anticipated from implementing PAR 1110.2.

Construction Criteria Emissions

Based on a survey of facilities with gaseous- and liquid-fueled engines, SCAQMD staff estimates that 242 engines would become subject to source tests starting in 2007; 240 facilities would require minor construction to install infrastructure (sampling ports, platforms, safe access and utilities) by September 2008; 16 facilities are expected to need air/fuel ratio controllers installed in 2009; 20 facilities would need installation of CO analyzers; 24 NOx-CO CEMS are expected to be installed by July 2011; seven facilities would need oxidation catalyst by July 2011; 45 facilities would need modification to enhance three-way catalyst by July 2011; and 28 facilities would need SCR by July 2012. Table 4-32 presents the number of facilities requiring some type of construction activity and the compliances dates when construction must be completed.

Table 4-32
Number of Facilities Where Construction Activities Are Expected to Occur

Project - Facilities	2008	2009	2010	2011	2012	Total
Increased Source Testing	242					242
Inspection & Monitoring	242					242
Install Sampling Infrastructure	240					240
Install AFRC		16				16
Upgrade Three-Way Catalyst			15	30		45
Install Oxidation Catalyst			5	2		7
Install CEMS		4	10	10		24
Install CO Analyzer			15	5		20
Install Pretreatment, SCR, Ox Cat or ICE Alternative Technology					28	28
Facilities with Electrified Engines		4	13	88		105

Construction to install new or modify existing control technologies; replace engines with electric motors; or install infrastructure may require cranes, loaders, forklifts, welders and generator sets. Installation of controllers, analyzers, and CEMS systems are likely to require less heavy equipment. All construction would require delivery truck and worker trips. Table 4-33 presents expected construction equipment expected to be required for the various compliance options.

Construction emission calculations are based on the expected number of facilities expected to be affected and the construction schedule (Table 4-33). Tables 4-34 and 35 show total peak daily construction emissions for each year up to the final compliance date for the various compliance options. The peak daily construction emissions shown in Tables 4-34 and 4-35 assume that operators 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines, a total of 624 engines, would comply with PAR 1110.2. Table 4-34 shows the construction emissions for biogas and non-biogas facilities by compliance year for the compliance option of all biogas plant operators retrofitting their equipment with SCR, replacing ICEs with gas turbines or replacing ICEs with microturbines. Table 4-38 shows the remaining emissions for biogas and non-biogas facilities by compliance year for the compliance option of digester operators replacing ICEs with gas turbines or microturbines and landfill gas facility operators replacing ICEs with LNG plants. Details of the construction analysis can be found in Appendix C.

Table 4-33
Construction Equipment by Technology Installed or Replaced

Compliance Option/Equipment	Construction Equipment Type	No. of Construction Equipment	Operation Time hour/day
ICE engine removal, three-way catalyst, SCR, NOxTech, CL.AIR®, gas turbine, boiler, microturbines, fuel cell, emergency diesel ICE - Paving	Pavers	1	4
	Paving Equipment	1	4
	Rollers	1	2
	Cement and Mortar Mixers	1	3
	Tractors/Loaders/Backhoes	1	4
ICE engine removal, three-way catalyst, SCR, NOxTech, CL.AIR®, gas turbine, boiler, microturbines, fuel cell, emergency diesel ICE - Construction	Cranes	1	7
	Rubber Tired Loaders	2	7
	Forklifts	3	7
	Welder	1	7
	Generator Sets	1	7
Source Testing Infrastructure, CEMS	Cranes	1	4
	Rubber Tired Loaders	1	4
	Forklifts	1	4
	Welder	1	7
	Generator Sets	1	7
CO Analyzer, ATRC	Forklifts/Electric Lift	1	4
LNG Plant - Grading	Scrapers	1	8
	Graders	1	8
	Tractors/Loaders/Backhoes	1	7
LNG Plant - Paving	Pavers	1	8
	Paving Equipment	1	8
	Rollers	2	8
	Cement and Mortar Mixers	1	3
	Tractors/Loaders/Backhoes	1	8
LNG Plant - Construction	Cranes	2	7
	Rubber Tired Loaders	2	7
	Forklifts	2	7
	Welder	3	7
	Generator Sets	3	7

Table 4-34
Criteria Construction Emissions for Biogas and Non-biogas Facilities from Installing SCR, Gas Turbines or Microturbines at All Biogas Facilities

Description*	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	89.8	42.1	12.0	0.08	5.0	4.6
2009	88.9	39.5	11.1	0.08	4.7	4.4
2010	141.4	61.8	17.6	0.13	7.4	6.9
2011	247	106	30.4	0.23	12.9	11.9
2012	52.5	22.3	6.4	0.05	2.7	2.5

* Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-35
Criteria Construction Emissions for Biogas and Non-biogas Facilities from Installing Gas Turbines or Microturbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description*	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	90	42.1	12.0	0.08	5.0	4.6
2009	88.9	39.5	11.1	0.08	4.7	4.4
2010	141.4	61.8	17.6	0.13	7.4	6.9
2011	682	291	84.1	0.60	48.4	35.6
2012	488	206.6	60.2	0.43	38.3	26.2

* Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

As shown in Tables 4-34 and 4-35, operators of biogas facilities who choose the compliance options of replacing ICEs with alternative technologies, LNG plants in particular, would require the most construction equipment, therefore creating the highest peak daily construction emissions. However, not all biogas facilities would have enough space to install LNG plants, as these plants may require up to three acres of land. It is not likely that most digester gas facilities would have the sufficient available space to install LNG facilities. In addition, LNG facilities require the highest capital expenditures. The CEC estimates that gas turbines may be a better option than ICEs for facilities between 10 to 18 MW when all factors (e.g., economic, emissions, etc.) are taken into account.[26]

[26] CEC, Landfill Gas-To-Energy Potential in California, Staff Report, 500-02-041V1, September, 2002.

Criteria Pollutant Significance Determination

Since construction and operational activities overlap during certain years, the criteria pollutants peak daily emissions were estimated per PAR 1110.2 implementation year and 2014 which represents an average operational year. The year 2014 was chosen as an average operational year since routine catalyst replacement would begin in 2014. Since it was assumed that SCR catalysts would be replaced every three years and biogas facility operators are not expected to install add-on control or ICE replacement technology until after the technology review in 2010; therefore, routine catalyst replacement at biogas facilities would not occur until after the year 2012, starting approximately in 2014.

As noted previously, the analysis peak daily construction emissions assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) because this is expected to be a less costly compliance option than other compliance options. Further, the analysis assumed that operators of all remaining non-biogas engines, a total of 624 engines, would to comply with PAR 1110.2.

Tables 4-36 through 4-40 present the total net remaining emissions by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with PAR 1110.2 and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. The tables take into account all secondary adverse operational air quality impacts described in the above subsections. Table 4-36 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-37 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-38 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-39 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-40 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Finally, the remaining inventory for the year 2014 for each of the scenarios is shown in Tables 4-36 through 4-40 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life.

Table 4-36
Net Remaining Criteria Emissions from Non-biogas Facilities and the SCR Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,591~~ 5,596	~~13,581~~ 13,614	~~1,237~~ 1,246	~~529~~ 530	~~834~~ 835	~~831~~ 832
2012	4,178	13,445	1,017	538	833	831
2014	4,184	13,441	1,015	538	833	831

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (ICE) and offsite travel (delivery trucks).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

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Table 4-37
Net Remaining Criteria Emissions from Non-biogas Facilities and the Gas Turbine Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	4,878	7,380	539	538	1,019	1,017
2014	4,884	7,375	537	538	1,019	1,017

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-38
Net Remaining Criteria Emissions from Non-biogas Facilities and the Microturbine Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	3,913	6,192	644	538	760	758
2014	3,919	6,187	643	538	760	758

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-39
Net Remaining Criteria Emissions from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,742	6,710	584	211	911	896
2014	4,373	6,540	533	211	878	876

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-40
Net Remaining Criteria Emissions from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,358	6,245	629	211	805	791
2014	3,989	6,075	578	211	773	771

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Tables 4-41 through 4-45 show the net emissions effect taking into consideration emissions reductions from affected equipment reducing emissions to comply with PAR 1110.2 and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. The tables take into account all secondary adverse operational air quality impacts described in the above subsections. Table 4-41 shows the net emissions effect by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-42 shows the net emissions effect by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-43 shows the net emissions effect by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-44 shows the net emissions effect by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-45 shows the net emissions effect by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Finally, the net emissions effect for the year 2014 for each of the scenarios is shown in Tables 4-41 through 4-45 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life. Construction will be completed by 2012 so no construction emissions are included in the year 2014. Secondary air quality impacts, as described in previous sections, are included since these will be ongoing.

Table 4-41
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(23)~~	~~(7.4)~~	~~0.1~~	~~0.4~~
	(100)	(301)	(14)	(6.8)	1.0	0.7
2009	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,603)~~	~~(40,662)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,598)	(40,629)	(1,247)	(22)	(42)	(43)
2012	(5,017)	(40,798)	(1,476)	(13)	(44)	(44)
2014	(5,011)	(40,802)	(1,477)	(13)	(44)	(44)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (ICE) and offsite travel (delivery trucks).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-42
Criteria Net Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(23)~~	~~(7.5)~~	~~0.1~~	~~0.4~~
	(100)	(301)	(14)	(6.8)	1.0	0.7
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)
2012	(4,317)	(46,863)	(1,954)	(13)	142	142
2014	(4,311)	(46,868)	(1,955)	(13)	142	142
Positive Emissions Increase					142	142
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	Yes

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-43
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)
2012	(5,282)	(48,051)	(1,848)	(13)	(117)	(117)
2014	(5,275)	(48,056)	(1,850)	(13)	(117)	(117)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-44
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)
2012	(4,453)	(47,533)	(1,909)	(340)	33.7	21.3
2014	(4,821)	(47,703)	(1,960)	(340)	1.2	0.75
Positive Emissions Increase					33.7	21.3
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-45
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)
2012	(4,837)	(47,998)	(1,864)	(340)	(72)	(84)
2014	(5,205)	(48,168)	(1,914)	(340)	(104)	(104)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

As shown in Table 4-42, the compliance option in which all biogas facility operators replace ICEs with gas turbines would exceed the regional operational significance threshold for PM2.5 in the years 2012 and 2014. As shown in Tables 4-44 through 4-48, implementing PAR is not expected to result in an exceedance of any operational significance thresholds for VOC emissions or any other criteria pollutants.

Toxic Air Contaminant Impacts

Operational Toxic Air Contaminant Emissions

Adverse health risk effects are estimated by evaluating the impact of toxic air contaminants (TACs) upon receptors surrounding a TAC emissions source. Carcinogenic and chronic noncarcinogenic impacts are evaluated from sources that generate TACs with carcinogenic and chronic noncarcinogenic health risk values consistently over a long period of time (e.g., 70 years for sensitive receptors or 40 years for occupational receptors.). Acute impacts are evaluated from TACs with acute noncarcinogenic health risk values over a short period of time (one hour).

PM emissions from diesel exhaust have carcinogenic and chronic noncarcinogenic health effects. No acute noncarcinogenic health risk values have been established for diesel exhaust. Diesel PM10 carcinogenic health risks are evaluated from mobile sources, i.e., emissions diesel truck delivery trips and from stationary sources, i.e., emissions from emergency backup generators. Health effects from diesel particulates emitted from these two primary sources are evaluated in the following subsections. Chronic and acute non-carcinogenic health risks were examined for ammonia slip from the two largest biogas facilities.

Diesel Delivery Truck Trips

Diesel Delivery Truck Trips to LNG Facilities: The LNG facilities have the potential to generate diesel delivery truck trips because of the need to transport LNG to potential customers off-site. However, as noted previously, only the landfill gas operations are expected to be able to replace ICEs with LNG facilities because of the large space requirements of LNG facilities.

It is estimated that a facility generating the largest volume of LNG would generate approximately 4,715,897 gallons of LNG per year. Based on this volume and a standard LNG truck carrying capacity of 10,000 gallons per truck, approximately 472 annual truck trips would be required. Because these facilities need to pre-treat the landfill gas, an additional four truck trips per year (once every three months) would be required to remove carbon from the pretreatment filter and another four truck trips would be necessary to deliver replacement carbon. One truck would be needed to remove catalyst and one to deliver catalyst. Assuming that trucks idle for 15 minutes per trip at the facility (five minutes at the gate, five minutes before delivery and five minutes after delivery), the health risk from diesel exhaust for a sensitive or residential receptor 25 meters away would be 2.0×10^{-9}, which is less the SCAQMD's cancer risk significance threshold of ten in one million (10×10^{-6}). Similarly, the greatest chronic hazard index level from diesel exhaust PM from diesel deliver trucks would be 1.3×10^{-3}, which is well below the chronic hazard index significance threshold of 1.0. Additional information regarding this analysis can be found Appendix C.

Diesel Delivery Truck Trips to Digester Gas Facilities: Facility operators who retrofit existing equipment with SCR control equipment are not expected to need new emergency backup engines. As a result, no additional diesel truck trips would be generated by these facilities. Since landfill gas operations are not expected to need emergency backup engines and can flare landfill gas in the event of power outages, no carcinogenic risks from diesel emergency engines were assumed to occur. Diesel emergency engines are expected to be needed at digester gas facilities to operate pumps or compressors. Truck trips to digester gas facilities would be necessary to supply diesel fuel. While at total of 178 diesel truck trips may occur in one year for all affected facilities, the number of diesel truck delivery trips to a specific facility is expected to be less than two per year, which is expected to be less than the carcinogenic significance threshold.

Diesel Emergency Backup Generators

Biogas Facilities: Facility operators who replace natural gas ICEs with electric motors and diesel emergency generators would operate a maximum of 50 hours per year with commensurate diesel exhaust particulate matter emissions per year.

It is expected that operators of digester plants where ICEs are either replaced by alternative compliance technologies or add-on control technology is applied, would need emergency backup generators to make-up electricity loss by either the difference in efficiency between the existing ICE and alternative technologies or pressure losses from add-on control technology. A health risk analysis was completed for diesel exhaust particulate matter from the two biogas facilities that are expected to emit the most diesel particulate matter exhaust. The largest facility operates four 4,166 bhp digester gas engines; the other operates two 3471 bhp digester gas engines. It was assumed that the emergency engines would be placed in the same location as the existing natural gas engines and that the emission parameters would be similar. To be conservative, health risk was estimated from the highest off-site concentration assuming the receptor at that location was a sensitive or residential receptor. At both facilities that receptor is a worker receptor. The greatest carcinogenic health risk generated from the use of diesel fueled emergency generators would be 3.4 in one million (3.4×10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (10×10^{-6}). The greatest chronic hazard indices from diesel particulate matter exhaust would be 0.002, which is less than the chronic hazard index significance threshold of 1.0. The target organ for diesel exhaust particulate toxicity is the respiratory system. Long-term exposure to diesel exhaust can cause chronic respiratory symptoms and reduced lung function, and may cause or worsen allergic respiratory diseases such as asthma. Additional information regarding this analysis can be found Appendix C.

Non-biogas Facilities: As presented in the criteria pollutant analysis, the peak daily operational emissions assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) because this is expected to be a less costly compliance option than other compliance options. Further, the analysis assumed that operators of all remaining non-biogas engines, a total of 624 engines, would to comply with PAR 1110.2. It is assumed that: operators of 40 percent of these engines would use the existing engines as emergency generators; operators of 20 percent of these engines would use diesel-fueled emergency engines; and operators of the remaining 40 percent of are not assumed to need an emergency engine. Non-biogas emergency generators have higher power ratings than biogas facilities because biogas emergency engines were sized for the efficiency loss between the existing ICE and the add-on emissions control or ICE alternative technology; where non-biogas emergency engines were sized to generate equivalent electricity or shaft work as the electric motor. The three facilities with the largest facilities are not near residential or sensitive receptors. The health risk at the worker receptors near these facilities are below the significance threshold of one in a million. However, the facility with engines with the fourth largest net horsepower would generate a health risk of 18 in one million (1.8×10^{-5}), which is greater than the significance threshold of 10 in a million (1×10^{-5}). The facility has six 634 bhp natural gas engines used to run pumps. The facility with engines with the fourth largest net horsepower would have a chronic non-carcinogenic health risk of 0.014. The chronic non-carcinogenic health risk from these facilities is much less than the significance threshold of 1.0.

Ammonia Slip Emissions

Facility operators may install SCR or NOxTech control systems on existing ICEs as possible compliance options. Both technologies can use either urea or aqueous ammonia to control NOx emissions. The amount of slip is expected to be independent of whether urea or ammonia is used.

Ammonia, though not a carcinogen, can have chronic and acute health impacts. Staff estimates approximately 3.64 pounds of ammonia per brake horsepower would be required to reduce NOx. Similar to the above analysis of diesel particulate matter exhaust health risk analysis, health risks from ammonia were examined at the two facilities with the largest ammonia emissions. The maximum acute hazard index is expected to be 0.4. The greatest chronic hazard index from ammonia at either of the two facilities with the largest ammonia emissions would be 0.97. The target organ for chronic ammonia toxicity is the respiratory system. The target organs for acute ammonia toxicity are the eyes and the respiratory system. Ammonia can cause inflammation of the respiratory tract, which can lead to wheezing, shortness of breath, and chest pain. Inhalation of vapor from concentrated, industrial strength ammonia may cause burns to the respiratory tract. Eye exposure can cause tearing, inflammation, and irritation to temporary or permanent blindness.

Operational Health Risks Conclusions

Health risks are estimated for receptors around a specific source. Health risk from sources at the same facility are additive by type of health risk. Carcinogenic health risks are additive. Non-carcinogenic chronic risks are estimated by target organ and are additive per similar target organ. Non-carcinogenic acute risks are estimated by target organ and are additive per similar target organ. Acute and chronic risks cannot be added together. If facilities are close together (typically within a mile), then the health risk from each facility at receptors shared by the two facilities can be added together.

The preceding cancer and noncancer health risk analyses resulted in the following conclusions. Cancer risk at biogas facilities where operators who would choose to replace existing ICEs with LNG plants from diesel trucks was concluded to be 1.99 x 10^{-9}, which is less the SCAQMD's cancer risk significance threshold of ten in one million (10 x 10^{-6}). Noncancer chronic health risks were concluded to be 0.0013, which is well below the chronic hazard index significance threshold of 1.0. Diesel truck trips to digester gas facilities were expected to have negligible health risk effects.

For facility operators at non-biogas facilities who replace natural gas ICEs with electric motors and diesel emergency backup generators, the maximum cancer risk from installing emergency diesel backup generators is approximately 18 in one million (1.8 x 10^{-5}), which is greater than the significance threshold of 10 in one million (1 x 10^{-5}). The non-carcinogenic chronic hazard index from this facility is 0.014, which is less than the significance threshold of 1.0.

The greatest carcinogenic health risk generated from biogas facilities where operators of digester plants replace ICEs with alternative compliance technologies and use diesel fueled emergency backup generators would be 3.4 in one million (3.4 x 10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (1 x 10^{-5}). The greatest chronic hazard indices from diesel particulate matter exhaust at this facility would be 0.002, which is less than the chronic hazard index significance threshold of 1.0.

Ammonia, used as a reducing agent in SCR and NOxTech control technologies, though not a carcinogen, can have chronic and acute health impacts resulting from ammonia slip. The maximum acute hazard index from ammonia slip emissions would be 0.4, which is less than the acute hazard index significance threshold of 1.0. Since ammonia is the only toxic in this analysis with an acute effect, PAR 1110.2 would not be significant for acute health risk. The greatest chronic hazard index from ammonia at either of the two facilities with the largest ammonia emissions would be 0.97.

At any single biogas facilities, it was assumed that biogas operators would install the same add-on control technology for all of the biogas engines or remove the existing ICEs and replace them with the same alternative ICE technology (i.e., all gas turbines, microturbines or biogas-to-LNG plant). However, some biogas facilities have both biogas and non-biogas engines at the same location. The worst-case carcinogenic health risk could occur at a facility that had both biogas and non-biogas emergency engines. However, the carcinogenic health risk at the facility with both biogas and non-biogas emergency engines should be below the sum of the health risk of the biogas facility with the largest carcinogenic risk and the non-biogas facility with the largest carcinogenic health risk (3.4 in one million + 18 in one million = 21.4 in one million), which is greater than the significance threshold of ten in a million ($1.0x10^{-5}$).

The sum of the hazard indices of the biogas facility with the largest non-carcinogenic risk and the non-biogas facility with the largest non-carcinogenic health risk would be less than the significance threshold of 1.0 (0.97 +0.014 = 0.98).

Based on the above results, implementing PAR 1110.2 has the potential to generate significant cancer risks, but insignificant acute hazard impacts, and insignificant acute and chronic hazard impacts.

<u>The exemptions would only allow affected facilities to operate at existing levels, there would be no new toxic effects. Some TACs are also considered VOCs. While the VOC limit has increased for new DG engines from the proposal in the Draft EA, the new VOC limits will still be less than the existing BACT limit of 30 ppm VOC; therefore, toxic emission are still expected to be reduced from baseline.</u>

<u>Construction Toxic Emissions</u>

Diesel particulate matter has carcinogenic and chronic non-carcinogenic effects from long-term exposure. Diesel particulate matter does not have acute health risk values. Carcinogenic health risk is estimated over 70 years for sensitive and residential receptors and 40-years for worker receptors. To calculate carcinogenic and chronic non-carcinogenic health risks, annual concentrations data are required. Construction at any facility to comply with the most construction-intensive PAR 1110.2 compliance option (landfill gas to LNG plant) is expected to be limited to no more than 105 days. Construction for other PAR 1110.2 compliance requirements is expected to last one or two days at most. Since the various construction scenarios do not provide one year's worth of concentration data and the exposure duration to construction emissions associated with complying with PAR 1110.2 is much shorter than 70 years (for sensitive receptors) or 40 years (for worker receptors), carcinogenic and chronic non-carcinogenic health risk from construction activities associated with complying with PAR 1110.2 is expected to be less than significant.

<u>Changes to PAR 1110.2 since the Draft EA was release would not require additional construction.</u>

<u>Odor Impacts</u>

Under normal operating and permitted conditions, ammonia slip is approximately five to 10 ppm. Because exhaust gases are hot, any ammonia slip emissions would be quite buoyant and would rapidly rise to higher altitudes without any possibility of lingering at ground level. The odor threshold of ammonia is one to five ppm, but because of the buoyancy of ammonia emissions and an average prevailing wind velocity of six miles per hour in the Basin, it is unlikely that ammonia slip emissions would exceed the odor threshold. Based on the Tier II health risk analysis the highest concentration at the facility with the greatest ammonia slip would be 0.26 ppm which is below the odor threshold of ammonia.

No more than four diesel truck trips are expected at any affected facility per day. Because diesel trucks are limited to five minutes of idling at a single time by state regulation, no adverse odor impacts are expected.

Emergency ICE engines are limited to 50 hours of operation per year for testing. Testing events typically don’t last more than 30 minutes and usually no more frequently than once per week. Because of this limitation no odor impacts are expected.

<u>The exemptions would allow affected engines to operate at current levels during emergencies and certain weather conditions; therefore, no new odor emissions are expected. The increases in VOC and CO emission limits for new DG engines would be less than existing BACT for new engines; therefore, PAR 1110.2 would reduce emissions that may cause odors.</u>

<u>Global Warming Impacts</u>

As indicated in Chapter 3, combustion processes generate greenhouse gas (GHG) emissions in addition to criteria pollutants. The following analysis focuses on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. CO2 emissions were estimated using emission factors from CARB’s EMFAC2007 and Offroad2007 models and EPA’s AP-42.

The analysis of GHGs is a much different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants significance thresholds are based on daily emissions because attainment or non-attainment is based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health, e.g., one-hour and eight-hour. Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs are longer-term, affecting global climate over a relatively long time frame. As a result, the SCAQMD current position is to evaluate GHG effects over a longer timeframe than a single day. Although GHG emissions are typically considered to be cumulative impacts because they contribute to global climate effects, this ~~Draft~~Final EA for PAR 1110.2 analyzed the GHG emissions as project specific impacts because of the close relationship between CO and CO2 emissions from compliance options. For example, installation of oxidation catalyst to reduce CO emissions has the potential to increase CO2 emissions. Alternatively, replacing ICEs with electric motors reduces direct CO2 emissions, while incrementally increasing CO2 emissions from utility power generating equipment.

SCAQMD staff assumed for the CEQA analysis, that for some categories of ICEs, it may be less costly to install electric motors than comply with PAR 1110.2. SCAQMD staff identified 225 ICEs were it would be less costly to install electric motors (see Table 4-8). To provide a conservative analysis, staff assumed that operators of only 75 percent of these engines, 169 engines, would install electric motors. Electric motors are estimated to have a lifespan of 10 years. For the purposes of addressing the GHG impacts of PAR 1110.2, the overall impacts of CO2 emissions from the project were estimated and evaluated from initial implementation of the proposed project in 2009 through 2019 (i.e., over the lifespan of the electric motors). While the analysis was only completed over the lifespan of the electric motor, it is expected that the reduction would continue, since facility operators would be expected to replace electric motors with another electric motor once the original is replaced.

The analysis estimated CO2 emissions from all sources (primary and secondary, construction and operation) from the beginning of the proposed project to the end of the project. The beginning of the proposed project would be 2009, since it was assumed that electric motors would be install starting in 2009. The end of the proposed project for this analysis is the 2018, which correlates to the useful life of an electric motor. With electric motors the proposed project would have a reduction in CO2 over the ten years. Without the electric motors in the proposed project there would be an increase in CO2 over the same time frame.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new CO2 emissions would be generated. VOC and CO emissions limits for new DG engines have increased; however, the lower emissions would have been achieved either by more efficient combustion or add-on control technology. More efficient combustion and add-on control technology would covert CO to CO2. Since more CO would be allowed, less CO2 would be emitted. Therefore, the changes to PAR 1110.2 since the Draft EA would only reduce the amount of CO2 generated.

Minimum Number of ICEs That Are Required to Prevent a Net Increase in CO2 from PAR 1110.2

Since the proposed project would generate CO2 without replacement of some non-biogas engines with electric motors, SCAQMD staff estimated the minimum number of non-biogas engines that would need to be replaced in order prevent a net CO2 increase. The analysis was based on average CO2 emissions per engine. Staff believes this to be a conservative approach since larger and more heavily used engines are more likely to be electrified. To prevent a net increase in CO2 emissions, approximately 15 of the 225 non-biogas ICEs that are expected to have lower cost by replacing ICEs with electric motors than complying with PAR 1110.2 requirements would need to be replaced with electric motors. This is summarized in Table 4-49. A description of worst-case compliance option is included in the first column. The second column shows the CO2 emission reductions for the project with electric motors. The third column present the CO2 emission increases without electric motors. The fourth column shows the CO2 reductions that would occur with the electric motors. The fifth column shows the average CO2 savings per electric motor. The last column presents the number of electric motors that would be required for a reduction of CO2 emissions.

Conclusion

Based on the above air quality analysis, implementing PAR 1110.2 is expected to generate overlapping operational and construction emissions that have the potential to exceed the operational directly emitted PM2.5 significance threshold by 25 pounds (142 pounds per day – 55 pound per day PM2.5 significance threshold, see Table 4-42) for the gas turbine biogas compliance option. PAR 1110.2 would also be significant for carcinogenic health risk from diesel emergency engines during operations at non-biogas facilities. Therefore, PAR 1110.2 is significant for air quality for operational and construction criteria pollutants and carcinogenic health risk. Because of the expected replacement of some non-biogas engines with electric motors, CO2 emissions are expected to be reduced by PAR 1110.2.

Table 4-46
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under the Worst-Case (Gas Turbines)

Gas Turbines – CO2 Reductions

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
Baseline					
2008	(22,186)	(22,181)	5		
2009	121,080	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(52,600)	(21,905)	30,695		
2012	(18,703)	11,236	29,938		
2014	(18,776)	11,163	29,938		
2013-2018	(112,654)	66,976	179,630		
10 year total	(104,849)	9,591	114,439	677	15

Electric motors were assumed to have a ten year lifespan (2009 the expected start date of ICE replacement with electric motors to 2019).

It is possible that fewer than 169 non-biogas engines could be replaced with electric motors, but, given the lower costs of installing and operating electric motors, it is likely that at least 15 non-biogas engines or more would be replaced with electric motors.

<u>Exceptions and increase in VOC and CO emission limits for new engines added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new adverse air</u>

quality impacts were identified. Based on the above analysis, the new exceptions and increase in VOC and CO emission limits for new engines would not make an adverse air quality impact that was identified as not significant, significant; nor make an adverse air quality impact that was already identified as significant in the Draft EA substantially worse.

Project Specific Mitigation Measures: PM2.5 emissions contributing the to the criteria pollutant significance determination are generated by gas turbines, if this compliance option is chosen instead of complying with biogas requirements of PAR 1110.2. In addition, secondary PM2.5 emissions from emergency diesel backup generators gas turbines and for electric motors installed at non-biogas facilities, diesel trucks transporting materials, e.g., catalyst, activated carbon, etc., to and from affected facilities, and power plant emissions would occur. Based on the gas turbine biogas compliance option, PAR 1110.2 has the potential to emit 142 pounds of PM2.5 per day.

New gas turbines installed as a compliance option instead of complying with PAR 1110.2 would likely be subject to Rule 1303 or Rule 2005 BACT requirements. No add-control technology has been identified to reduce PM2.5 emissions from gas turbines.

Emergency diesel backup generators installed at non-biogas facilities would likely be subject to particulate requirements of Rule 1470. The analysis of air quality impacts assumed that emergency diesel backup generators would comply with Rule 1470 requirements, cancer risk was still significant under the gas turbine compliance options (see Table 4-42). To further reduce diesel PM emissions diesel particulate filters (DPFs) will be required for any emergency diesel backup generators used at non-biogas facilities where operators install electric motors and the carcinogenic health risk exceeds 10 in one million ($1x10^{-5}$). DPFs allow exhaust gases to pass through the filter medium, but trap diesel PM. Depending on engine baseline emissions and emission test method or duty cycle, DPFs can achieve a PM emission reduction of greater than 85 percent. In addition, DPFs can reduce HC emissions by 95 percent and CO emissions by 90 percent. Limited test data indicate that DPFs can also reduce NOx emissions by six to ten percent. Most DPFs require periodic regeneration, most commonly achieved by burning off accumulated diesel PM. There are both active DPFs and passive DPFs. Active DPFs use heat generated by means other than exhaust gases (e.g., electricity, fuel burners, microwaves, and additional fuel injection to increase exhaust gas temperatures) to assist in the regeneration process. Passive DPFs, which do not require an external heat source to regenerate, incorporate a catalytic material, typically a platinum group metal, to assist in oxidizing trapped diesel PM. Although there is a slight increase in directly emitted NO_2 during the regeneration of passive DPFs, overall there is ultimately a net reduction in NO_2 emissions. Many engines can also limit their testing to be less than 30 hours per year to reduce carcinogenic health risk to below 10 in one million.

Since facility operators typically do not own the diesel delivery trucks, no mitigation is available to reduce the significant carcinogenic health risk from diesel delivery trucks.

The exceptions and increase in VOC and CO emission limits for new engines added to the proposed project after the Draft EA was circulated for public review do not make adverse air quality impacts, identified in the Draft EA as not significant, significant; nor substantially increase the severity of an air quality topic that was identified as significant in the Draft EA. In addition, the exceptions and increase in VOC and CO emission limits for new engines would not make an air quality topic that was identified as mitigated to not significant, significant; nor substantially increase the severity of an air quality topic that was mitigated, but still significant in the Draft EA.

Remaining Air Quality Impacts: Based on a PM control efficiency of 85 percent from installing DPFs on emergency diesel backup generators, it is expected that PM2.5 emission impacts from gas turbines, delivery trucks and diesel emergency backup generators would remain significant. DPFs are only expected to reduce PM2.5 emissions from emergency diesel backup generators by approximately one pound per day. DPFs installed on diesel backup generators are, however, expected to reduce significant adverse cancer risks to less than significant. The maximum cancer risk at the largest non-biogas facility can be reduced from approximately 18 in one million (1.8×10^{-5}) to approximately 4.5 in one million (4.5×10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (1.0×10^{-5}). Even if the carcinogenic heath risk from both the biogas and non-biogas facilities were added together (21.4 in one million or 2.14×10^{-5}), DPF would reduce the carcinogenic health risk to less than significant ($2.14 \times 10^{-5} \times (1-0.85) = 3.21$ in one million).

The exceptions and increase in VOC and CO emission limits for new engines added after the Draft EA was circulated for public review would not substantially alter the remaining air quality impacts or generate new remaining air quality impacts.

Cumulative Air Quality Impacts: The preceding analysis concluded that project-specific PM2.5 emissions from overlapping construction and operational activities for the gas turbine control option component of the proposed project would be significant because the SCAQMD's operational significance threshold for PM2.5 would be exceeded. However, PAR 1110.2 is part of a comprehensive ongoing regulatory program that includes implementing related SCAQMD 2007 AQMP control measures as amended or new rules to attain and maintain with a margin of safety all state and national ambient air quality standards for all areas within its jurisdiction. Only the compliance option that includes replacing all biogas engines with gas turbines would generate significant PM2.5 emissions. No other compliance options would result in significant adverse regional air quality impacts for any criteria or precursor pollutants. Since no other compliance option exceeds any project-specific regional significance thresholds, they are not considered to be cumulatively considerable. Although the gas turbine compliance option would exceed the project-specific PM2.5 operational significance threshold, it is also expected to generate 4,311 pounds of NOx reductions per day and 1,955 pounds of VOC reductions per day. Both NOx and VOCs are precursors to PM2.5. According to the 2007 AQMP, the NOx equivalency factor for PM2.5 is 9.9 tons per day per ton of PM2.5 and the VOC equivalency factor for PM2.5 would be 23.0 tons per day per ton of PM2.5. This means that reducing one ton of NOx per day is equivalent to reducing 0.1 ton per day of PM2.5 and reducing on ton of VOC is equivalent to reducing 0.04 tons per day of PM2.5. Therefore, the large reductions in NOx and VOC emissions from the gas turbines would more than make up for any increases in direct PM2.5 emissions. Based on this rationale, PM2.5 emissions from the gas turbine scenario are not considered to be cumulatively considerable. Therefore, PAR 1110.2 would not be cumulatively significant for PM2.5.

Relative to GHGs, implementing PAR 1110.2 is expected to reduce CO2 emissions. Therefore, implementing PAR 1110.2 is not expected to generate significant adverse cumulative criteria or GHG air quality impacts.

As noted in the air toxics analysis, project-specific carcinogenic health risk from PAR 1110.2 can be mitigated to less than significant. Since air toxics create localized effects and no facilities regulated by PAR 1110.2 are within two miles of each other, implementing PAR 1110.2 is not expected to create significant adverse cumulative carcinogenic health risks.

Since the exemptions and increase in VOC and CO emission limits for new engines that were added after the Draft EA was circulated for public review were not determined to generate new project-specific adverse impacts, nor substantially increase the severity of adverse impacts that were already identified as significant; the new exceptions were not generate new cumulative adverse impacts or make adverse cumulative impacts already identified substantially worse.

Cumulative Air Quality Impact Mitigation: As indicated in the preceding discussion, no significant adverse cumulative air quality impacts were identified, therefore, no cumulative impact mitigation measures are required.

Energy

Significance Criteria

Impacts to energy resources will be considered significant if any of the following criteria are met:

- 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 energy resources in a wasteful and/or inefficient manner.

New, Retrofit or Replacement Equipment for ICEs

An analysis was completed in the NOP/IS demonstrating that implementing PAR 1110.2 would not significantly adversely affect natural gas and electrical resources. However, based on comments received on the NOP/IS, potential adverse energy resources impacts from flaring and installing alternative technologies at biogas facilities instead of complying directly with PAR 1110.2 are analyzed in the following subsections.

PAR 1110.2 would require the construction and operation of control devices and monitoring equipment for both non-biogas and biogas facilities. The construction and operational phases would each have adverse energy impacts. Since construction and operation would overlap the concurrent effect of the construction and operational adverse impacts will be analyzed together.

Electricity Effects

2005 Baseline

The existing engines can be categorized as distributed generators and non-distributed generators. The non-distributed generators do not generate electricity for the facility at which they are located. These ICE instead produce work for pumps or compressors.

Distributed generators produce electricity for the facility at which they are located. Some distributed generators produce electricity for on-site activities. Others generate electricity for on-site activities; any additional energy is sold to the power grid.

The amount of electricity generated at existing facilities was estimated from the amount of fuel reported to the SCAQMD in the facility surveys. The total amount of electricity was estimated by the ratio of responses and the total number of PAR 1110.2 facilities in the SCAQMD permit database. Based on the SCAQMD inventory and survey data approximately 437,214 MW-hours per year were generated in 2005.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fuel. Therefore, there would be no additional electricity required. It is possible that welding may be performed with electricity from the power grid. However, because many of the existing engines are distributed generators, it is likely that electricity would not be available for construction. In addition, the electricity consumption for welders is expected to be small and short in duration. Therefore, no adverse electrical impacts are expected from construction of monitoring or control equipment.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new construction would be required. The increase in VOC and CO emission limits for new engines are not expected to alter the use of electricity in the construction of new diesel engine projects.

Operations

Non-biogas Add-on Control and Monitoring Equipment

The additional monitoring and control equipment may require electricity from the existing ICE, ICE replacement or grid to operate. It was assumed that little electricity would be required for CO analyzers, AFRCs and add-on control equipment. CEMS systems were assumed to require 2.3 kW per CEMS. Based on this, approximately 511 MW-hours per year would be required for monitoring equipment.

Biogas Add-on Control or ICE Alternative

The proposed requirement to install CEMS systems on specified engines would be expected to increase demand for electricity. Based on the facilities survey, SCAQMD staff estimates that 56 MW-hr of electricity would be required to operate the additional CEMS systems.

Approximately 28 biogas facilities are expected to either need add-on control, such as SCR or NOxTech systems or to replace existing biogas ICEs with alternative technologies, such as turbines, microturbines, fuel cells, boilers, or LNG plants.

<u>SCR, NOx Tech Control Technologies</u>

SCR and NOxTech control technologies are expected to slightly reduce the efficiency of some ICEs due to pressure drops caused by the control devices and the need to use digester gas or natural gas to heat elements of the control technologies. The primary effect of this reduction in efficiency is a slight reduction in electricity production from affected ICEs. The electrical production losses (1,706 MWH per year) would be minor compared to alternative compliance options as explained in the following paragraphs.

<u>Turbines, Microturbines, Fuel Cells and Boilers</u>

Replacing ICEs with turbines, microturbines fuel cells and boilers would still allow operators at biogas facilities to generate electricity. Turbines, microturbines and boilers generate more waste heat than ICEs. Therefore, replacing ICEs with turbines, microturbines and boilers would reduce the amount of electricity generated. It is believed that most biogas facilities would be able to support gas turbines, microturbines, fuel cells or boilers; however, some digester gas facilities may not have the space (facility lot size) to support these ICE alternatives.

Electrical efficiency measures the amount of electrical energy produced per unit fuel energy input relative to the energy that is lost to heat or mechanical losses. Boilers are approximately 32 percent energy efficient. ICEs are approximately 31 percent energy efficient. Gas turbines are approximately 26 percent energy efficient and microturbines are approximately 23 percent energy efficient. Since turbines and microturbines are the least energy efficient option and the actual amount of space at digester gas facilities is unknown, turbines and microturbines would represent the "worst-case" loss of electricity production from removing ICEs at biogas facilities. There would be a 57,161 MWH per year reduction in electricity from gas turbines, and a 101,013 MWH per year reduction in electricity from microturbines.

<u>Biogas to LNG Facilities</u>

The existing LNG plant at the Bowerman Landfill includes ICEs to supply electricity to the facility. However, since it is assumed that LNG plants would be an alternative to complying with PAR 1110.2, it was assumed that LNG plants would obtain electricity from the power grid to operate the LNG plants. Therefore, since the ICEs would be removed and electricity would be supplied from the power grid, SCAQMD staff assumes that all electricity production from facilities installing biogas to LNG facilities is lost. The landfill gas would be treated and used off-site as fuel for another system or process. The existing Bowerman Landfill will sell the LNG to the Orange County Transit Authority. Similarly, affected facilities that chose to replace ICEs with LNG plants are expected to sell the LNG for fuel in other processes. Therefore, biogas-to-LNG facilities are expected to generate a new source of LNG that could be used in place of more polluting fuels such as diesel or gasoline.

As noted in the "Air Quality" analysis section, LNG plants require substantial area because of the size and number of components needed to collect, scrub and cool biogas into LNG.

Not all biogas facilities have enough space to support an LNG plant. The analysis of the effects of replacing ICEs with LNG plants includes the following assumptions. Only landfill gas facilities are assumed to have enough area to allow installation of an LNG plant.

The differences in electricity production between the existing ICEs and ICE alternatives are presented in Table 4-50. These differences are based on differences in efficiencies between ICE alternatives and the existing ICEs.

New Exceptions and Increases in VOC and CO Emission Limits for New Engines

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse electricity impacts would be generated. The increase in VOC and CO emission limits for new engines would not affect the use of electricity; therefore, not new adverse electrical impacts are expected.

Total Electricity Adverse Impacts

Table 4-51 presents the energy production and usage for ICEs retrofitted with applicable control technologies to comply with PAR 1110.2 and for replacing ICEs with alternative technologies. All alternative generate less electricity than the existing ICEs because they are less efficient than ICEs. Biogas-to-LNG plants would not generate any electricity but received electricity from the power grid. However, biogas-to-LNG plants would generate renewable LNG (See Renewable Energy below). Therefore, any compliance option would reduce the total amount of renewable electricity available to the grid.

Table 4-47
Adverse Electricity Impacts from Differences in Efficiency between ICE Alternatives and LNG Reliance on the Power Grid

Description	Electricity Production, MWH/yr	Electricity Consumption, MWH/yr	Total Electricity, MWH/yr	Reduction in Electricity from Baseline, MWH/yr
2005 Baseline (ICE)	437,214		437,214	
SCR	435,509		435,509	1,706
Gas Turbines	380,053		380,053	57,161
Microturbines	336,201		336,201	101,013
Gas Turbines/LNG	155,746	104,694	51,052	386,162
Microturbines/LNG	137,706	104,694	33,081	404,133

ICEs, gas turbines, and microturbines generate electricity.
LNG plants would not generate electricity, but would require energy from the power grid.

Table 4-48
Total Adverse Electricity Impacts from PAR 1110.2

Description	Non-Biogas and Biogas CEMS and Controllers, MWH/Yr	Non-Biogas Electrification, MWH/Yr	Electricity Production, MWH/yr	Electricity Totals, MWH/yr	Reduction in Electricity from Baseline,, MWH/yr
2005 Baseline			437,214	437,214	0
SCR	(567)	(171,827)	435,509	263,114	(174,100)
Gas Turbines	(567)	(171,827)	380,053	207,659	(229,556)
Microturbines	(567)	(171,827)	336,201	163,807	(273,408)
Gas Turbines/LNG	(567)	(171,827)	51,052	(121,342)	(558,557)
Microturbines/LNG	(567)	(171,827)	33,081	(139,313)	(576,527)

Negative values are presented in parenthesis. Negative electricity values represent consumption, positive values represent production.

According to the Final Program EIR for the 2007 AQMP, 120,194 GW-hours per year were available in southern California in 2002. Table 4-51 shows that 576,527 MW-hour per year would be consumed in a worst-case. A 576,527 MW-hour per year reduction is 0.48 percent of 120,194 GW-hour per year. Since the worst-case PAR 1110.2 scenario would reduce the total amount of electricity available by less one percent, it is not significant for adverse total electricity impacts.

Natural Gas Effects

2005 Baseline

The baseline amount of natural gas of approximately 10,501,630 MMBtu per year (10,028,802 MMBtu per year at non-biogas facilities and 472,828 MMBtu per year at biogas facilities) was estimated from the amount of natural gas use reported in the facility surveys. This information was multiplied by the ratio of total number of Rule 1110.2 facilities to the number of facilities that completed the survey.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fuel. Therefore, there would be no additional natural gas required.

Operations

Non-biogas Add-on Control and Monitoring Equipment

The addition of three way catalyst is expected to result in a pressure drop. The pressure drop would result in an increase in natural gas usage. SCAQMD staff assumed a one-inch pressure drop in the exhaust of an ICE with three way catalyst. The increase in natural gas consumption caused by monitoring equipment is expected to be negligible. Approximately 2,713 MMBtu per year would be consumed because of increased pressure loss.

Limitation of Natural Gas Use on Biogas Engines

PAR 1110.2 would eliminate the efficiency correction factor in 2012. However, between the date of adoption and July 1, 2012, PAR 1110.2 would allow the use of the efficiency correction factor for facility operators who operate engines using 90 percent or more landfill or digester gas. SCAQMD staff expects that most digester gas generators rated greater than 500 bhp would reduce natural gas used to less than 10 percent upon adoption of the rule in 2008 in order to use the efficiency factor. In 2010, the concentration limits for engines comprised of greater than 10 percent biogas would become effective. Biogas engines that use 10 percent or more natural would need to either reduce natural gas to less than 10 percent or meet the 2010 concentration limits. SCAQMD staff expects that the remaining digester gas ICE rated greater than 500 bhp would reduce to less than 10 percent to remain subject to the biogas concentrations. Operators of biogas engines are not expected shut down their engines because of the 90 percent or more landfill or digester gas requirement in subparagraph (d)(1)(B) for the following reasons:

Based on the survey of affected engines conducted by staff, operators of 24 of 26 landfill gas engines use no natural gas. Operators of the remaining two engines use 12 percent natural gas and could reduce this amount to less than 10 percent. Operators of 11 of 27 digester gas engines were reported to use less than 10 percent natural gas. Three more have recently reduced natural gas usage to less than 10 percent. Eleven of the 13 remaining digester gas engines that use more than 10 percent natural gas generate electricity, which means they can either limit their natural gas usage or petition to use a higher percentage of natural gas, if qualified. Operators of the remaining two engines, which drive compressors, may also be eligible to petition for a higher percentage of natural gas usage than 10 percent if they demonstrate that using 10 percent or less natural gas would result in flaring the biogas.

However, while the natural gas will likely be reduced until 2012, SCAQMD staff expects that facility operators will return to the original natural gas consumptions after 2012, since the biogas efficiency correction factor will be eliminated at that time. The reduction of natural gas usage to 10 percent is presented in Table 4-49.

Table 4-49
Reduction of Natural Gas Usage to 10 Percent between 2008 and 2012

Year	Baseline Natural Gas Usage, MMBtu/ year	2008 Natural Gas Reduction, MMBtu/ year	2010 Natural Gas Reduction, MMBtu/ year
2008	4,061,047	162,928	77,761
2010	4,964,605	199,179	95,063

Biogas Add-on Control or ICE Alternative

Approximately 28 biogas facilities are expected to either need add-on control, such as SCR or NOxTech systems or to replace existing biogas ICEs with alternative technologies, such as turbines, microturbines, fuel cells, boilers, or LNG plants.

SCAQMD did not expect a change in the usage of natural gas between the biogas compliance options, except for LNG plants, which are not expected to need natural gas.

The exceptions added after the Draft EA was circulated for public review would allow affected engines to use existing levels of natural gas during emergencies and certain weather conditions; therefore, no new natural gas usage is expected. The new VOC and CO limits for new DG engines are not expected to increase the amount of natural gas needed.

Emergency Generators

Non-biogas Emergency Generators

There would, however, be a reduction in natural gas usage if facility operators replace ICEs with electric motors. As noted in the analysis of potential air quality impacts from implementing PAR 1110.2, it was assumed that operators of 169 engines at non-biogas facilities would choose to replace their existing engines with electric motors. Staff assumed that 40 percent of these operators would choose to use their existing natural gas engines as emergency backup engines. If 169 non-biogas ICEs are replaced by electric motors, it is estimated that natural gas usage would be reduced by approximately 1,854,358 MMBtu per year. Approximately 1,303,214 MMBtu per year would be consumed at power plants to generate electricity for the 169 existing ICES that would be assumed to be replaced with electric motors. If 40 percent of the 169 existing ICEs use existing natural gas engines for emergency backup, an additional 2,283 MMBtu per year would be needed. A summary of natural gas consumption and reduction associated with non-biogas ICE replacement with electric motors is presented in Table 4-53.

Table 4-50
Natural Gas Consumption and Reduction Associated with Non-biogas ICE Replacement with Electric Motors

Natural Gas Reduction from ICE Replacement with Electric Motors, MMBtu/year	Power Plants Natural Gas Consumption, MMBtu/year	Emergency ICE Natural Gas Consumption, MMBtu/year	Electrification Natural Gas Consumption, MMBtu/year
(1,854,358)	1,303,214	2,283	(548,862)

Values in parentheses are negative. Reduction in natural gas use is negative, consumption is positive

Biogas Emergency Generators

Facility operators that place add-on controls are not expected to need emergency generators because of PAR 1110.2. SCAQMD staff assumed that facility operators might install emergency generators if existing engines were replaced with ICE alternatives. SCAQMD staff assumed that only digester gas facility operators would install emergency generators, since pumps and compressors would be required to be operated continuously. SCAQMD staff assumes that landfill operators would flare landfill gas during emergencies to prevent explosions. In a worst-case (microturbines at all digester plants) approximately 5,023 MMBtu per year of natural gas would be consumed in biogas emergency generators.

Total Natural Gas Impacts

With the replacement of existing non-biogas ICEs with electric motors, PAR 1110.2 would result in an overall reduction in natural gas consumption. The reductions for the proposed project by biogas compliance option are present in Table 4-54.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse natural gas impacts would be generated. The increase in VOC and CO emission limits for new engines is not expected to affect the use of natural; therefore, no new adverse natural gas impacts are expected.

Diesel Fuel Effects

2005 Baseline

With the exception of 30 diesel-fueled ICE, the majority of the stationary ICEs subject to PAR 1110.2 are natural gas, biogas or field gas fueled. The 30 diesel fueled ICEs consume approximately 6,363,500 gallons of diesel fuel per year.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fueled. In addition to the construction equipment, delivery and haul trucks would bring supplies and equipment and remove old equipment. The maximum amount of diesel used per day in construction equipment would be 1,761 gallons per day under the biogas compliance options where digester gas facility operators replace ICEs with either turbines or microturbine and landfill gas facility operators replace ICES with LNG plants. The maximum amount of diesel used for construction vehicle travel would be 232 gallons per day for the same scenario.

Table 4-51
Total Adverse Natural Gas Impacts

Description	Catalyst Pressure Drop Consumption, MMBtu/yr	Non-biogas Electrification Natural Gas Consumption, MMBtu/yr	Biogas Emergency Engines Natural Gas, MMBtu/yr	Power Plant Natural Gas, MMBtu/Yr	Biogas Natural Gas Consumption, MMBtu/yr	Non-biogas Natural Gas Consumption, MMBtu/yr	Natural Gas Total, MMBtu/yr	Natural Gas Change from Baseline, MMBtu/yr
Baseline					512,787	10,501,630	11,014,417	
SCR	2,713	(548,862)		1,751	512,787	10,501,630	10,470,019	(544,398)
Gas Turbines	2,713	(548,862)	3,318	68,793	512,787	10,501,630	10,540,378	(474,039)
Microturbines	2,713	(548,862)	5,023	112,645	512,787	10,501,630	10,585,936	(428,481)
Gas Turbines/ LNG	2,713	(548,862)	3,318	397,794	456,430	10,501,630	10,813,022	(201,395)
Microturbines/ LNG	2,713	(548,862)	5,023	415,764	456,430	10,501,630	10,832,698	(181,719)

Values in parentheses are negative. Reduction in natural gas use is negative, consumption is positive

Operation

Vehicle Traffic

Diesel fuel would be consumed by source testing trips, trucks delivering catalysts, ammonia, etc., hauling away spent carbon and catalyst, and trucks hauling LNG offsite to customers. The amount of diesel fuel usage was estimated by the number of affected facilities or material delivered. Diesel fuel use from truck trips associate with PAR 1110.2 are presented in Tables 4-55 through 4-59. Detailed calculations can be found in Appendix C.

Diesel Emergency Generators

An indirect affect of facility operators replacing existing natural gas engines with electric motors and replacing biogas engines with alternative technologies would be the installation of diesel emergency engines to provide power to necessary operations during power failures in the electricity supply grid. Emergency engines were assumed to operate up to 50 hours per year based for testing (maximum allowed per Rule 1470). For this analysis, it was assumed that the brake horsepower rating of the emergency engines installed would be based on increased grid dependence in the case of digester gas generators or would be equivalent to the brake horsepower rating of the existing digester or natural gas work (pump or compressor) engine replaced. The worst-case biogas scenario would require 202 gallons per day of diesel fuel for emergency engines for microturbines used for digester gas facilities and 1,111 gallons per day for emergency generators at non-biogas facilities. Diesel emergency engine ICE fuel consumption is presented in Tables 4-52 through 4-56.

Total Diesel Fuel Adverse Impacts

SCAQMD staff estimates that a maximum of 3,218 gallons of diesel might be consumed per day. The 2007 AQMP states that 10 million gallons of diesel is consumed per day in California. Three thousand, two hundred and eleven gallons of diesel is less than one percent of the 10 million gallons of diesel used in California (0.02 percent). Therefore, the increase in diesel consumption caused by PAR 1110.2 would not be significant. Diesel fuel use from PAR 1110.2 is presented in Tables 4-55 through 4-59. Detailed calculations can be found in Appendix C.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse diesel impacts would be generated. The increase in VOC and CO emission limits for new engines would not affect the use of diesel; therefore, no new adverse diesel impacts are expected.

Renewable Energy

Flaring

Representatives of the Landfill Gas to Energy Coalition stated that the cost of installing SCR control equipment to comply with the proposed NOx concentration limits would make flaring gas more economically appealing than installing SCR. They stated further that if the ICEs were removed and landfill gas was flared, PAR 1110.2 could adversely affect California's renewable energy goals.

Table 4-52
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the SCR Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	300
2009	20	279	6	65	370
2010	28	373	54	760	1,214
2011	44	653	63	1,111	1,871
2012	8	141	86	1,111	1,346
2014	0	0	149	1,111	1,260
Max	44	653	149	1,111	1,871

HHDT = Heavy – heavy- duty truck

Table 4-53
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	367	6	65	0	458
2010	28	373	54	760	0	1,214
2011	44	653	57	1,111	0	1,865
2012	8	141	86	1,111	0	1,346
2014	0	0	149	1,111	140	1,399
Max	44	653	149	1,111	140	1,865

HHDT = Heavy – heavy- duty truck

Table 4-54
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	367	6.0	65	0	458
2010	28.0	373	53.6	760	0	1,214
2011	44.0	653	56.6	1,111	0	1,865
2012	8.0	141	86.4	1,111	0	1,346
2014	0.0	0	149	1,111	202	148.8
Max	44	653	149	1,111	202	1,865

HHDT = Heavy – heavy- duty truck

Table 4-55
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the LNG and Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	279	6	65	0	370
2010	28	373	54	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0	0	281	1,111	140	1,531
Max	236	1,761	281	1,111	140	3,218

HHDT = Heavy – heavy- duty truck

Table 4-56
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the LNG and Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	279	6.0	65	0	370
2010	28.0	373	53.6	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0.0	0	281	1,111	202	1,593
Max	236	1,761	281	1,111	202	3,218

HHDT = Heavy – heavy- duty truck

In response to the Landfill Gas to Energy Coalition's concerns PAR 1110.2, staff has incorporated as part PAR 1110.2 a requirement to perform a technology assessment July 1, 2010 to evaluate the availability of cost effective compliance options for operators of ICEs at landfill gas and digester gas facilities. The technology assessment would evaluate whether available control technologies in 2010 would reduce NOx, VOC, and CO emissions to the concentration limits in PAR 1110.2 by July 1, 2012. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts.

PAR 1110.2 includes an alternative compliance limit in subparagraph (d)(1)(B) for operators of engines that operate on 90 percent or more of landfill or digester gas effective July 1, 2012. Further, at the request of the affected industry, staff has added a provision allowing operators of engines to operate on less than 90 percent landfill or digester gas if the only alternative would be shutting down and flaring the landfill or digester gas. This concentration limits for engines burning 90 percent or more landfill or digester gas is also subject to the technology review provision that has been added to PAR 1110.2. Based on these new provisions added to PAR 1110.2 additional flaring beyond existing conditions is not anticipated as a result of implementing PAR 1110.2.

Renewable Electricity and Fuel

In-state electricity from biomass represents almost two percent of the total electricity capacity in California. Of this two percent, approximately 33 percent, or 0.66 percent, of electricity produced from biomass is produced from the combustion of landfill and biogas. In Executive Order S-06-06 Governor Schwarzenegger targeted the state to meet a 20 percent target for biomass within the established state goals for renewable generation by 2010, that is, electricity from biomass should contribute 20 percent of the state's goal for 20 percent renewable electricity. Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) established the California Renewables Portfolio Standard (RPS) program, which requires an annual increase in renewable generation by the utilities equivalent to at least one percent of sales, with an aggregate goal of 20 percent by 2017. The PUC accelerated the goal, requiring the utilities to obtain 20 percent of their power from renewable sources by 2010 (Senate Bill 107 codified this goal in state law).

The CEC states that statewide, 305 MW are available from landfill gas operations and 68 MW from digester gas operations in California. Based on 974 MW of total biomass electrical capacity in the state, landfill gas operations could provide 31 percent of the total potential biomass electrical capacity and digester operations could provide seven percent of the total potential biomass electrical capacity.[27] The total potential biomass electrical capacity is the amount of electricity available from all existing and future biomass sources. The term “potential” is used because not all of the sources may be converted to electricity producing sources. As part of the potential feedstock energy in biomass for California in 2006, wastewater was two percent and landfill gas was eleven percent of the 507 trillion Btu per year.

Since a goal of the technology analysis under PAR 1110.2 would be to prevent flaring of natural gas and SCAQMD staff believes that facilities operators will either use add-on control or replace ICEs with alternative technologies that would either generate electricity or LNG; there would be only adverse impacts from efficiency losses between the existing ICEs and the ICEs with add-on control or ICE replacement technologies. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. The efficiency losses are reported in Table 4-47. The largest renewable energy electrical loss because of differences in efficiency would be 101,013 MW-hours per year for the microturbine compliance option.

Southern California Edison reports that electricity from biomass and waste is projected to be two percent in 2007, which is equivalent to the actual power mix in 2006. LADWP projects electricity from biomass and waste to be one percent in 2007. The state power mix from biomass and waste was less than one percent in 2005.

There may be adverse energy impacts from an individual government program, but any energy losses caused by PAR 1110.2 other than from efficiency losses from one program (e.g., RPS electricity) would be made up in another program (e.g., biofuel). The RPS program focuses only electricity sold on the power grid. The program also allows up to 25 percent of natural gas to be reported as renewable biogas. For example, a facility operator might use 25 percent natural gas, and all of the electricity generate from the 25 percent natural gas might be sold to the power grid. If the facility operator then reduces the amount of natural gas to 10 percent, then the facility might report to the state that there was a reduction of renewable electricity equivalent to the 15 percent natural gas (25 percent – 10 percent). In reality, no renewable biogas electricity has been loss, only the electricity loss

[27] Table 2.1, CEC, A Preliminary Roadmap for the Development of Biomass in California, CEC-500-2006-095-D, December 2006.

from natural gas that was allowed to be reported as natural gas was loss. In addition, SCAQMD staff expects that facilities that use more than 10 percent natural gas would resume using the same amount used pre-PAR 1110.2 after 2012 when the concentration requirements for both the non-biogas and biogas become the same.

Another example of this would be if a biogas facility operator replaces an existing ICE with a LNG plant. The facility operator might report to under the state RPS program that after the replacement that the facility no longer produces electricity from biogas. However, while the facility operator would not generate electricity, the facility operator would ~~be~~ generate LNG to be used in replacement of gasoline or diesel.

New Exceptions and Increases in VOC and CO Emission Limits in New Engines

The new exceptions would allow the existing use of natural gas during emergencies and certain weather conditions. The new exemptions are not expected to affect the use of renewable energy. Therefore, the exceptions would not decrease natural use between 2008 and 2011. The increase in VOC and CO emission limits in new engines is not expected to alter the use of renewable or natural gas. Therefore, the new exemptions and increases in VOC and CO emission limits for new engines are not expected to make new adverse renewable energy impacts.

Total Renewable Energy Affects

Therefore, based on the above analysis, PAR 1110.2 would not generate any adverse impacts for energy. PAR 1110.2 includes a technology assessment that will include the goal of preventing adverse energy impacts from becoming significant. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts.

Project Specific Mitigation Measures:

PAR 1110.2 is not designed to cause facilities to stop electric generation, but to reduce NOx, CO and VOC from ICEs. However, the cost of control and monitoring technology along with other business and economic factors may spur affected facility operators to remove ICEs and install alternative technologies. SCAQMD staff will conduct a technology assessment in 2010 to prevent affected facility operators from flaring biogas rather than using it for electricity or biofuel production. By preventing continuous flaring SCAQMD staff will prevent the loss of renewable energy in both electricity and biofuel form.

Remaining Energy Impacts:

The proposed project does not have any significant adverse energy impacts. A technology assessment will be completed in 2010 to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts, including rule changes if needed. Therefore, there would be no significant adverse energy impacts from PAR 1110.2.

Cumulative Energy Impacts:
Since PAR 1110.2 would not have project specific adverse impacts to energy, it would not have cumulative impacts.

Cumulative Energy Impact Mitigation:
Since there are no cumulative energy impacts no mitigation is required.

Hazards and Hazardous Materials

Accidental releases of aqueous ammonia used to reduce NOx emissions in SCR control technologies were examined in the following subsections. The analysis also evaluates accidental releases of LNG in scenarios where operators choose the alternative compliance option of replacing their ICEs with biogas to LNG plants. Since operators who retrofit existing ICEs with SCRs would not produce LNG and, conversely, facility operators who replace ICEs with biogas to LNG plants would not install SCR, the adverse impacts from accidental release from these materials would not occur at the same facility.

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action.

Aqueous Ammonia

Only biogas facilities would need SCR. All non-biogas, non-RECLAIM, lean-burn ICEs meet BACT. Existing, non-biogas, RECLAIM, lean-burn ICEs are exempt from NOx requirements in Rule 1110.2 and PAR 1110.2. One compliance option for operators of biogas facilities to comply with the NOx concentration requirement of PAR 1110.2 would be to install SCR or NOxTech systems at the 28 affected biogas facilities. As stated in the NOP/IS SCAQMD policy prohibits the use of anhydrous ammonia as a component in air pollution control technologies because it is considered to be an acutely hazardous material; in the event of an accidental release, ammonia will travel passively with prevailing winds as a dense gas; and can result in exposures that substantially exceed ERPG 2 levels. To further reduce potential hazards associated with exposure to ammonia in the event of an accidental release, a condition on SCAQMD permits is typically required that limits the aqueous ammonia concentration to 19 percent. The reason SCAQMD permits typically limit the concentration of aqueous ammonia to 19 percent is the fact that, in the event of an accidental release, it does not travel as a dense gas like anhydrous ammonia; is not on any hazardous material lists, like aqueous ammonia with higher concentrations; and, is less likely to evaporate and produce concentrations that exceed the ERPG 2 level used by the SCAQMD as a significance threshold.

Ammonia gas can cause severe eye damage, pulmonary edema, inflammation and edema of the larynx and death from spasm. Inhalation can cause wheezing, shortness of breath and chest pain. Inhalation of ammonia vapor can cause burns to the respiratory tract and residual chronic bronchitis. Chronic obstructive pulmonary disease can develop as a consequence of fibrous obstruction of the small airways. Exposure to the eyes can cause tearing, inflammation, and irritation to temporary or permanent blindness.[28]

Hazards due to transport of ammonia were evaluated in the NOP/IS. The NOP/IS concluded that PAR 1110.2 did not have the potential to create significant adverse ammonia transport impacts. No comments were received disputing this conclusion, so this topic will not be discussed further.

Hazards Due to Rupture

The ERPG 2 concentration level for ammonia is 150 ppm. Exposures to concentrations equal to or exceeding this concentration will be considered significant. "Worst-case" atmospheric conditions (e.g., low winds and stable air) will be used to evaluate whether accidental release concentrations exceed the ERPG-2 and ERPG-3 levels.

Affected operators who choose to retrofit existing ICEs with SCR or NOxTech systems would likely need to install ammonia storage tanks. Based on considerations like available area, amount of ammonia needed per year, etc., SCAQMD staff assumed that the largest ammonia tank installed to comply with PAR 1110.2 would be 5,000 gallons. Due to local fire department safety regulations, storage tanks constructed at affected facilities would be surrounded by secondary containment designs (e.g., dykes, berms, etc.). These same containment facilities would be provided at truck loading racks to contain ammonia in the event of a spill during transfer of ammonia from the truck to the storage tank.

The worst-case release scenario would be a catastrophic storage tank failure. The rupture of an ammonia storage tank would release the ammonia into the secondary containment area. Ammonia would then form a liquid pool in the secondary containment area and evaporate.

A modeling analysis was performed based on EPA's RMP Guidance for worst-case estimates for toxic releases and explosions. The RMPComp model was used to calculate the size of the impact zones. The EPA endpoint for ammonia exposure is the distance from the spill that is required to reduce the concentration to 0.14 micrograms per litter, the ERPG 2 endpoint for ammonia. The RMPComp program estimates were based on 20 percent aqueous ammonia, which is slightly higher concentration than the 19 percent ammonia proposed for this project. The 20 percent concentration is built into RMPComp and was the closest concentration available for use by the model.

[28] Technical Support Document: Toxicology Clandestine Drug Labs: Methamphetamine Volume 1, Number 1, Ammonia, ttp://www.oehha.ca.gov/public_info/pdf/TSD%20Ammonia%20Meth%20Labs%2010'8'03.pdf

To provide a "worst-case" case analysis for all ammonia tank release scenarios, the following assumptions were made:

- Ammonia tank dimensions were assumed to be twice as wide as they were high;
- The ammonia tank volume was assumed to be 10 percent larger than the nominal containment volume. (For a tank with 5,000-gallon contents, the tank volume was assumed to be 5,500 gallons);
- All dike areas were assumed to have excess capacity of 20 percent more than the tank contents. (The dike capacity for 5,000-gallon contents was assumed to be 6,000 gallons);
- All dike walls were assumed to be three feet high;
- For unconfined ammonia spills, the liquid was assumed to spread to a thickness of one centimeter in all directions on a flat impervious surface;
- Rural conditions were conservatively assumed to reduce dispersion.

Based on these assumptions, RMPComp estimates that the toxic endpoint would be 0.1 mile (528 feet) from the ammonia tank. Since biogas engines typically have back-up flare systems, it is assumed that the ICEs are not placed close to the property boundaries. However, based on a survey of biogas facilities, it was found that several facilities would have biogas engines within 0.1 mile of the property line. Therefore, it is expected in the event of an accidental release of ammonia from an ammonia storage tank at affected facilities, offsite receptors could be exposed to ammonia concentrations exceed the ERPG 2 for ammonia, 150 ppm.

According to the American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety[29], the mean time to catastrophic failure for a metallic storage vessel at atmospheric pressure is 0.985 per million hours (approximately once per 112 years). For aqueous ammonia tanks used at power plants, the California Energy Commission concluded that the catastrophic failure of an aqueous ammonia storage tank is an extremely unlikely event because the probability of a complete tank failure is insignificant, and the risk of failure due to other causes such as external events and human error also is insignificant.[30] In addition, SCAQMD staff is not aware of any aqueous ammonia storage tank that has had a catastrophic failure in recent history. As a result, the likelihood of a rupture of the aqueous ammonia storage tank occurring is extremely low. In spite of this, however, hazard impacts from exposure to ERPG 2 concentrations of ammonia are considered to be significant.

Liquefied Natural Gas

Operators who choose to replace their existing ICEs with biogas to LNG plants would also need to install LNG storage tanks to store LNG until loaded into delivery trucks. Both the storage tank and the delivery trucks would have the potential for accidental release.

[29] AIChE, 1989.
[30] CEC, 1999

Hazards associated with LNG are that, under certain conditions, it may explode or catch on fire. LNG is not explosive or flammable in unconfined areas.[31] However, as it warms and expands to a gas it becomes flammable at a concentration between five and 15 percent.

LNG is comprised mostly of methane, but may contain ethane, propane and other heavier hydrocarbons. There are no known health effects from methane except for asphyxia. Asphyxia is the condition of severely depleting the oxygen supply to the body. Methane causes asphyxia by displacing oxygen in air. Asphyxiation can occur when oxygen concentrations drop below 18 percent. Oxygen is displaced to 18 percent at a concentration of 14 percent methane. Unconsciousness from central nervous system depression occurs at 30 percent methane.

Effects of oxygen deficiency are:[32]

12-16 percent	Breathing and pulse rate are increased, with slight muscular incoordination;
10-14 percent	Emotional upsets, abnormal fatigue from exertion, disturbed respiration;
6-10 percent	Nausea and vomiting, inability to move freely, collapse, possible lack of consciousness;
Below 6 percent	Convulsive movements, gasping, possible respiratory collapse and death.

It is unlikely that off-site receptors would be exposed to LNG concentrations that would generate adverse health effects, because the lower explosive limit (LEL) for methane is five percent (50,000 ppm). The LEL is the concentration at which there is enough of the given gas to ignite or explode.

The methodology used for estimating the potential risk from a vapor explosion is that developed for off-site consequence analysis for the Risk Management Program (RMP) under 40CFR68 (EPA, 1999). For an RMP off-site consequence analysis, a gaseous release is assumed to produce a vapor explosion that results in a blast impact. For a vapor explosion, the significance level is a pressure wave (blast) of one pound per square inch (psi) and the metric examined is the modeled distance to the significant overpressure level.

<u>Hazards Due to Transport</u>

The transport of LNG is regulated by the US Department of Transportation. LNG trucks are double-walled aluminum and are designed to withstand accidents during the transport of LNG. The following description of LNG transportation and consequences is taken from the Federal Motor Carrier Safety Administration (FMCSA).[33]

[31] Federal Energy Regulatory Commission, http://www.ferc.gov/o12faqpro/default.asp?Action=Q&ID=470
[32] Canadian Centre for Occupational Health and Safety, http://www.ccohs.ca/oshanswers/chemicals/chem_profiles/methane/health_met.html
[33] Federal Motor Carrier Safety Administration, Comparative Risks of Hazardous Materials and Non-Hazardous Materials Truck Shipment Accidents/Incidents, Final Report, March 2001, www.fmcsa.dot.gov/documents/hazmatriskfinalreport.pdf.

LNG is loaded into delivery tanks at atmospheric pressure, which would be at its boiling point of -260ºF (-162ºC). The LNG is maintained at this temperature by evaporation of the boiling LNG and venting of the evaporated LNG. Because the vent is closed during shipment, the pressure in the tank builds and the temperature of the LNG increases. The FMCSA analyzed releases from delivery tanks with an average pressure of 30 psig, which would be -230ºF (-146ºC). At 30 psig, approximately 30 percent of the LNG will flash into vapor when released.

There are four scenarios that can have major consequences:

1. Release of LNG into a pool that evaporates and disperses without ignition. Approximately 40 percent of the liquefied LNG immediately flashes into vapor. The temperature of the liquid pool would be -44 ºF (-42ºC) and would therefore damage exposed vegetation and people.
2. A flammable cloud is formed that contacts an ignition source. The flame front can flash back and set the liquid pool on fire. Quantities of LNG shipped by truck would not typically cause vapor cloud explosions.
3. A boiling liquid expanding vapor explosion (BLEVE) occurs. BLEVEs would occur when an LNG tank is exposed to fire and the increase in pressure within the tank exceeds the capacity of the relief valve.
4. The tank ruptures, rockets away and ignites.

RMPComp was used for the consequence analysis for these four scenarios. The adverse impacts from the four scenarios are:

1. The area of the pool was estimated by assuming a depth of one centimeter as described in Example 29 in the EPA's Risk Management Program Guidance for Offsite Consequence Analysis.[34] A 6,000 gallon LNG pool would be 24,448 square feet. This distance would be a "worst-case" since as the LNG pool expands from the tank it will warm and evaporate.
2. A pool fire of 6,000 gallons that is released in one minute would result in a heat radiation endpoint (five kilowatts/square meter) of 0.2 mile. If a vapor cloud fire occurs, the estimated distance to the lower flammability limit would be 0.3 mile.
3. Based on 10,000 gallons the BLEVE would result in a fireball that may cause second-degree burns out to 0.3 mile.
4. The "worst-case" release estimate for 10,000 gallons in RMP*Comp is 0.3 mile from the vapor cloud explosion. Since, it is unclear as to how far away the tank would travel, it was assumed that the adverse impact would be 0.3 mile from where the tank lands. Damage to property and persons may occur from physical impact from the rocketing tank.

Because sensitive receptors may be within the endpoints above, PAR 1110.2 would be significant for hazards from accidental release of LNG during transport.

[34] EPA, Risk Management Program Guidance for Offsite Consequence Analysis, EPA 550-B-99-009, April 1989.

Hazards Due to Rupture

A "worst-case" analysis was completed for a typical LNG storage tank. Based on the landfill gas reported in the facilities survey, and based on design of the LNG facility at the Bowerman Landfill[35], the largest LNG tank would be 71,000 gallons. All LNG tanks were assumed to have a berm that holds ten percent more LNG than the storage tanks. RMP*Comp estimates the overpressure from a catastrophic release of 71,000 gallons of LNG with a berm to be 0.2 mile. Since it was determined that several facilities have engines within 0.1 mile of the property line, PAR 1110.2 would be significant for hazards from accidental release of LNG from a storage tank.

Ammonia/LNG Hazards to Schools

SCAQMD staff has geocoded biogas facilities. No biogas facilities are within one-quarter mile of a school. Based on the analysis in the "Air Quality" Section, PAR 1110.2 would reduce NOx, CO, and VOC emissions from ICEs. However, ICEs at biogas facilities that are retrofitted with SCR could generate ammonia emissions. Biogas LNG plants may have the potential to affect schools in the event of an explosion.

RMPComp was used to estimate the distance a pressure wave (blast) of one pound per square inch (psi) or the toxic end point of aqueous ammonia at these facilities would be less than the distance between the affected facilities and the schools. None of the facilities generated a toxic endpoint for ammonia or pressure wave of one psi that would reach a near-by school. Therefore, it is not expected that PAR 1110.2 would result in a safety hazard to local schools since the distance to the one psi pressure wave or toxic endpoint from affected biogas facilities is shorter than the distance from the facilities to the schools. Table 4-52 presents the facility distances to the schools and the distance to the toxic endpoint.

Table 4-57
Hazard Impacts from Affected Biogas Facilities to the Nearest Schools

Name of School	Distance to School (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
St. Edward the Confessor Parish	0.39	0.01	No	0.05	No
Capo Beach Calvary Schools	0.41	0.01	No	0.05	No
El Potrero Elementary	0.36	0.01	No	0.08	No

Hazards near Airstrips or Airports

Nine affected biogas facilities are within two miles of the following airports: Burbank, Chino Airport, Ontario International, Rialto Municipal, Riverside Municipal, San

[35] Prometheus Energy Company, Bowerman I Natural Gas Process Facility Project Description, prepared for SCAQMD, undated. The LNG storage tank proposed for the project would hold five days worth of LNG generated by the LNG facility.

Bernardino International, and Whiteman in Los Angeles County. These facilities are presented in Table 4-58.

An analysis similar to the one performed for schools was performed for airports within two miles of affected facilities. The results of the analysis indicate that no public airports or public use airports were found within the 0.1 miles (528 feet) toxic endpoint from a proposed ammonia tank. Similarly, a "worst-case" analysis was completed on each of these facilities based on the amount of LNG estimated from the landfill gas generated at the facility, then scaling the tank size from the estimated LNG generated by using the LNG facility Bowerman as a reference. RMPComp estimates the distance a pressure wave (blast) of one pound per square inch (psi) at these facilities would be less than the distance between the affected facilities and the airports. The greatest distance estimated was 0.2 miles. Therefore, although there are nine facilities within two miles of an airport or private airstrip, it is not expected that PAR 1110.2 would result in a safety hazard for the people residing or working in the project area.

Hazards to Other Non-Residential Sensitive Receptors

SCAQMD staff identified one non-residential sensitive receptor within one-quarter mile of an affected biogas facility (see Table 4-62). The toxic endpoint and overpressure of one psi overpressure are both less than the distance between the non-residential sensitive receptor and the affected biogas facility. Therefore, none of the affected biogas facilities are expected to adversely affect sensitive receptors from an accidental storage tank release.

Table 4-58
Affected Biogas Facilities within Two Miles of an Airport/Air Strip

Airports	Distance to Airport (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
Riverside Municipal	0.51	0.01	No	0.06	No
Ontario International	0.92	0.01	No	0.08	No
San Bernardino International	0.52	0.01	No	0.09	No
Whiteman, LA County	1.45	0.01	No	0.2	No
Rialto Municipal	0.49	0.01	No	0.08	No
Ontario International	1.58	0.01	No	0.08	No
Chino Airport	0.32	0.01	No	0.04	No
Burbank	1.18	0.01	No	0.1	No
Whiteman, LA County	1.97	0.01	No	0.1	No

Table 4-59
Facilities near Non-Residential Sensitive Receptors

Airports	Distance to Receptor (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
Childtime Children's Ctr	0.31	0.01	No	0.06	No

Conclusion

Delivery of ammonia was determined not to be significant in the NOP. In the above analysis catastrophic release from ammonia storage tanks was estimated to be above the ERPG 2 level of 150 ppm within 0.1 mile of the storage tank. Sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from ammonia storage.

Based on the above analysis, the one psi overpressure from the cataclysmic destruction of the LNG storage tank is expected to extend 0.2 mile from the LNG storage tank. Sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from LNG storage. During transportation of LNG, it was estimated that the adverse impacts from various releases would extend 0.3 mile. It is expected that sensitive receptors could be within 0.3 mile of roadway used by LNG trucks associated with PAR 1110.2. Therefore, PAR 1110.2 would be significant for accidental release from LNG transport.

PAR 1110.2 would be significant for accidental releases from ammonia storage, and delivery and storage of LNG.

The new exceptions and increase in VOC and CO emission limits for new engine is not expected to affect hazards or increase the use of hazardous materials. Therefore, the new exceptions and increases in VOC and CO emissions limits for new engines is not expected to make new adverse hazards/hazardous material impacts; nor substantially increase the severity of adverse hazards/hazardous material impacts that were already identified in the Draft EA.

Project Specific Mitigation Measures:

SCAQMD policy requiring the use of aqueous ammonia instead of anhydrous ammonia reduces adverse impacts from SCR units. In addition, the use of 19 percent aqueous ammonia reduces adverse impacts from SCR units. The location of the SCR unit is limited by the location of the ICEs and related systems.

Secondary containment (e.g. berms), valves that fail shut, emergency release values and barriers around ammonia or LNG storage tanks are design measures that are used to prevent the physical damage to storage tanks or limit the release of aqueous ammonia or LNG from storage tanks are typically required by local fire departments. Integrity testing of aqueous ammonia and LNG storage tanks assists in preventing failure from structural problems.

Further, as part of the proposed project, SCAQMD staff will require that affected facilities construct a containment system to be used during off-loading operations.

However, no additional mitigation measures were identified that would reduce the hazard and hazardous material impacts from ammonia or LNG to less than significant. Therefore, the remaining hazardous and hazardous material impacts from exposure to the ERPG 2 level of 150 ppm for ammonia and the one psi overpressure from the cataclysmic destruction of the LNG storage tank are considered to be significant.

Four accidental release scenarios were identified for the transport of LNG: release of LNG into a pool that evaporates and disperses without ignition; the ignition of a flammable cloud, a boiling liquid expanding vapor explosion (BLEVE) occurs, or the tank ruptures, rockets away and ignites. The worst-case endpoint from these scenarios is 0.3 miles from a vapor cloud fire, BLEVE or where rocketing tank would land. Assuming that these accidents would occur near receptors, PAR 1110.2 is significant for LNG accidental release during transport.

Remaining Hazards and Hazardous Materials Impacts:
Since no additional mitigation measures were identified that would reduce the hazard and hazardous material impacts from ammonia or LNG to less than significant, the remaining hazards and hazard material impacts remain significant.

Cumulative Hazards and Hazardous Materials Impacts:
As noted in previous subsections, the accidental release of aqueous ammonia during transport is not expected to result in exposures to ammonia exceeding the ERPG 2 level, 150 ppm that would be considered significant. Because receptors could be closer than 0.1 miles, an accidental release of ammonia onsite, either during unloading from a truck or an accidental release in the event of storage tank failure is considered significant. No mitigation measures were identified that could reduce project-specific releases of LNG offsite to less than significant.

Adverse impacts from an accidental release of aqueous ammonia and/or LNG are localized impacts (i.e., the impacts are isolated to the area around the facilities). None of the affected biogas facilities under PAR 1110.2 are located within one mile of each other. All aqueous ammonia toxic endpoints are equal or less than 0.1 mile and the distance of a pressure wave from an LNG release of one psi is less than or equal to 0.3 mile. Since none of the facilities are within one mile of each other, no receptors would be affected by accidents at multiple facilities. However, to the extent that affected biogas facilities are located near other facilities that have hazardous materials risks, the cumulative adverse hazard impacts from this project could contribute to existing nearby hazard risks from other projects. Therefore, cumulative hazard risks from implementing PAR 1110.2 are considered to be significant.

Cumulative Hazards and Hazardous Materials Impact Mitigation:
No additional mitigation measures were identified that reduce cumulative impacts from hazards and hazardous materials, to less than significant. Therefore, cumulative hazards/hazardous materials impacts remain significant.

Solid/Hazardous Waste

The proposed project may cause a one time increase in the quantity of waste generated at affected facilities if operators replace existing ICEs with new ICEs, catalysts, or catalyst to comply with PAR 1110.2 or replace existing ICEs with alternative control technologies. Installs of new or expanding old catalytic units (oxidation catalyst, three-way catalyst or SCR) could generate a new or increased spent catalyst waste stream.

<u>Significance Criteria</u>

The proposed project impacts on solid/hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

<u>Solid Waste – Replacement of Existing ICEs</u>

Solid or hazardous wastes generated from construction-related activities would consist primarily of materials from the demolition of existing air pollution control equipment and construction associated with new air pollution control equipment. Construction-related waste would likely be disposed of at a Class II (industrial) or Class III (municipal) landfill. There are 48 Class II/Class III landfills within the SCAQMD's jurisdiction. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there landfills that accept construction waste in Los Angeles, Orange, Riverside and San Bernardino counties have a combined remaining disposal capacity of approximately 750,846,000 cubic yards (1,250,367,507 tons).

As noted in previous sections in this chapter, SCAQMD staff estimates that, when compared to the cost of complying with PAR 1110.2; operators of approximately 225 non-biogas engines may elect to replace existing non-biogas engines with electric motors because this is expected to be a less costly compliance option. Further, operators of biogas facilities may replace ICEs with alternative ICE technologies, such as fuel cells, boilers, gas turbine, microturbines or LFG to LNG plants rather than comply with PAR 1110.2. As a worst-case scenario all biogas engines and 225 non-biogas engine may be removed by facility operators and replaced with alternative compliance options or electric motors, respectively. Under this scenario, up to 291 ICEs (225 non-biogas engines + 66 biogas engines) would be removed and replaced. Assuming that replacing an average engine would generate seven tons of waste, approximately 2,037 tons of waste could be generated from replacing 291 engines. The 2,037 tons of solid waste would be less than one percent (1.6×10^{-4} percent) of the remaining capacity limit, if it is conservatively assumed that one cubic yard of solid waste weighs one ton.

Solid waste that is 0.00016 percent of the total landfill disposal capacity of the district is well within the disposal capacity of district landfills. Further, even assuming that all 291 engines are removed, some engines may have relatively long useful lives remaining and would likely be resold outside of the district. Those engines not resold outside of the district contain a large percentage of useful metals and, therefore, would more likely be dismantled and sold as scrap metal. Consequently, the actual amount of material disposed of in local district landfills would be substantially less than estimated here. As a result, solid waste impacts from removing and disposing of existing engines to comply with PAR 1110.2 are not anticipated to be significant.

Solid/Hazardous Waste – Catalyst

PAR 1110.2 could generate potentially significant hazardous wastes from replacing spent catalyst generated by new or modified oxidation and SCR units. PAR 1110.2 would generate a one time disposal of catalyst from existing three-way catalyst that need to be replaced to comply with PAR 1110.2. The proposed project would eventually generate a continuous stream of hazardous waste materials from upgraded or new catalyst units. Catalysts, either oxidation catalyst, three-way catalyst or SCR, can last up to five years depending on actual operating conditions. To provide a conservative analysis, SCAQMD staff assumed that oxidation catalyst, three-way catalyst and SCR catalysts would be replaced every three years.

Operators of facilities where affected large engines have existing catalyst-based control equipment, may regenerate, reclaim or recycle the catalysts, in lieu of disposal. In the past, due to the heavy metal content and its relatively high cost, recycling oxidation catalysts has been a lucrative choice. In some cases operators of equipment retrofitted with SCR catalysts have contractual agreements with the catalyst manufacturer to reclaim and recycle the catalysts upon replacement. Although in some situations it is expected that spent catalysts could be reclaimed and recycled, it is possible that spent catalysts could be disposed of. The composition of the catalyst will determine in which type of landfill a catalyst would be disposed. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified.

Catalysts with a metal structure would not normally be considered a hazardous waste. Instead, it would be considered a metal waste, like copper pipes, and, therefore, would not be a regulated waste requiring disposal in a Class I landfill unless it is friable or brittle. Ceramic-based catalysts are not considered friable or brittle because they typically include a fiber binding material in the catalyst material. Furthermore, typical catalyst materials are not considered to be water soluble. As a result, and depending on the actual catalyst material, spent catalyst would not require disposal in a Class I landfill.

Based on the above information, it is likely that spent catalysts would be considered a "designated waste," which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (CCR, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts could be disposed of in a Class II landfill or a Class III landfill that is fitted with liners.

PAR 1110.2 is expected to generate 95.7 tons of catalysts over three years (14.3 tons for upgraded systems, 45.3 tons for new three way catalysts, and 36.1 tons for SCR systems) (details of the analysis can be found Appendix C), which would be slightly more than 31 tons per year based on replacing catalysts every three years.

There are 48 Class II/Class III landfills within the SCAQMD's jurisdiction. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there landfills that accept construction waste in Los Angeles, Orange, Riverside and San Bernardino counties have a combined remaining disposal capacity of approximately 750,846,000 cubic yards (1,250,367,507 tons). The estimated life of the district landfills range from one year (Bradley Landfill in Los Angeles County) to 60 years (Prima Deschecha in Orange County). The total daily permitted disposal capacity of district landfills is approximately 93,979 tons per day[36]. If all 36.1 tons of catalyst material generated each year were disposed of on the same day, the catalyst material would represent 0.03 percent of the total district permitted disposal capacity. Solid waste that is 0.03 percent of the total daily permitted landfill disposal capacity for landfills in the district is well within the disposal capacity of district landfills.

However, if the oxidation catalyst, three-way catalyst and SCR catalyst are designated Class I waste, then it is expected that the catalysts would be disposed in one of three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA or Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors Buttonwillow and Westmorland have a combined remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036. Based on the closure dates the three facilities would receive approximately 708,472 cubic yards of hazardous waste per year. Thirty-six tons per year would be less than one percent (0.004 percent) of the average hazardous waste that would be received based on the closure dates and remaining capacity. Based on these results, if catalysts were classified as a hazardous waste, there is sufficient disposal capacity in California to accommodate this amount of waste.

Therefore, whether the catalysts are disposed of as solid or hazardous waste the adverse impacts would be less than significant. The above analysis represents a "worst-case" analysis because some catalysts may be recovered and recycled, either for reuse as a catalyst or for other uses. For example, some ceramic-based SCR catalysts can be crushed and used in cement for construction projects. Further, depending on actual operating conditions at affected facilities, catalysts would not need to be replaced every three, but could last as long as five years. Based upon these considerations, significant adverse solid/hazardous waste impacts are not expected from the implementation of the proposed project.

Project Specific Mitigation Measures:

Since no significant adverse impacts were identified, no project-specific mitigation measures are required.

[36] SCAQMD. 2007. Final Program Environmental Impact Report for the 2007 Air Quality Management Plan. (SCH. No.2006111064).

Remaining Solid/Hazardous Waste Impacts:

Since no significant adverse impacts were identified, there are not remaining solid/hazardous waste impacts.

Cumulative Solid/Hazardous Waste Impacts:

Since no significant adverse project-specific solid/hazardous waste impacts were identified, these impacts are not considered to be cumulatively considerable as defined in CEQA Guidelines §14064(h)(1). As a result, no cumulative solid/hazardous waste impacts are expected from implementing PAR 1110.2.

Cumulative Solid/Hazardous Waste Impact Mitigation:

Since no significant adverse cumulative solid/hazardous waste impacts were identified, no cumulative 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 to determine if the proposed amended rule would create significant impacts, the screening analysis concluded that the following environmental areas would not be significantly adversely affected by PAR 1110.2: agriculture resources, biological resources, cultural resources, geology/soils, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, and transportation/traffic. These topics were not analyzed in further detail in this environmental assessment, however, a brief discussion of each is provided below.

Agriculture Resources

Implementation of PAR 1110.2 would not result in any new construction of buildings or other structures that would convert farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract. There are no provisions in the proposed amended rule 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 will be altered by the proposed project. Therefore no significant impacts to agricultural resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect agricultural resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse agricultural impacts significant.

Biological Resources

PAR 1110.2 would only apply to equipment or processes located within the confines of commercial or industrial facilities in commercial or industrial areas, which have already been greatly disturbed. In general, these areas currently do not support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the affected facilities. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. Further, a conclusion of the 2003 AQMP EIR was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities (e.g., air quality control measures or regulations). The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions.

There are no provisions in the proposed amended rule 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 will be altered by the proposed project. PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Therefore, no significant impacts to biological resources are expected.

<u>Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect biological resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse biological impacts significant.</u>

Cultural Resources

There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. PAR 1110.2 is not expected to result in heavy earthmoving construction or operations, no impacts to historical resources will occur as a result of this project. Consequently, the proposed project has little or no potential to disturb cultural resources. Therefore, PAR 1110.2 has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. Further, PAR 1110.2 is not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the district. Therefore, no significant impacts to cultural resources are expected.

<u>Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect cultural resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse cultural impacts significant.</u>

Geology and Soils

The proposed project is not expected to require heavy earthmoving. Construction may be required for retrofit, replacement or new equipment. Biogas facilities may replace ICEs with turbines, microturbines, boilers or biogas to LNG facilities. The most construction occur if ICEs where replaced with LNG facilities. SCAQMD staff has had discussions with Apollo energy, which installed and operates the biogas to LNG plant at Bowerman. The biogas-to-LNG facilities are modular and dropped into place at biogas facilities. The LNG facilities are built to be modular to allow for operations to be scaled down and removed in the future. Therefore, heavy construction is not expected. Any construction is expected to follow the Uniform Building Code, which includes geological and soil safety provisions. Thus, the proposed project would not induce or alter the exposure of people or property to geological hazards such as expansive soils, lateral spreading, subsidence, liquefaction or collapse, earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death is not anticipated. Therefore, no significant impacts to geology and soils are expected.

<u>Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect geology and soils. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse geology and soils impacts significant.</u>

Hydrology and Water Quality

PAR 1110.2 may require the replacement or retrofit of ICE systems. PAR 1110.2 has no provision that would require the use of water or the disposal of wastewater.

Subsequent to the release of the NOP/IS, SCAQMD staff has determined the biogas operators may replace their ICEs with turbines, microturbines, boilers or biogas to LNG facilities. Based on the industry survey, biogas facilities currently remove water from biogas operations. Systems that replace ICEs would still need to remove water. SCAQMD staff expects that biogas operations would remove water in same fashion as it is removed now. For biogas facilities currently managing stormwater, PAR 1110.2 is not expected to alter the existing stormwater practices. Therefore, PAR 1110.2 is expected to be less than significant for hydrology and water quality.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, is not expected to use or discharge water. The increase in VOC and CO emission limits for new engines is not expected to use or discharge water. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse hydrology and water quality impacts significant.

Land Use and Planning

There are no provisions in the proposed amended rule 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 will be altered by further monitoring and emission reductions from ICEs. All proposed operations are expected to occur within the confines of the existing commercial and industrial facilities. Since the proposed amended rule would only affect ICE systems, PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. No new development or alterations to existing land designations will occur as a result of the implementation of the proposed amended rule. Therefore, no significant adverse impacts affecting land uses are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect land use and planning. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse land use and planning impacts significant.

Mineral Resources

There are no provisions of the proposed project that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan. Therefore, no significant adverse impacts to mineral resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect mineral resources. The increase in VOC and CO emission limits for new engines is not expected

<u>cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse mineral resource impacts significant.</u>

Noise

The existing noise environment at each of the affected facilities is dominated by industrial equipment, vehicular traffic around the facilities, and trucks entering and exiting the facilities. However, since activity during high wind event is not expected to be any greater than activity during normal operation, noise from the proposed project is not expected to produce noise in excess of current operations at each of the existing facilities. It is expected that commercial and industrial facilities affected by PAR 1110.2 would continue to comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA have established noise standards to protect worker health. These potential noise increases are expected to be less than significant, thus, implementing PAR 1110.2 is not expected to result in significantly adverse noise impacts.

<u>Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development, no increase in noise is expected. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse noise impacts significant.</u>

Population and Housing

Modifications to existing ICEs would occur completely within existing industrial facilities. The proposed project is not anticipated to generate any significant effects, either direct or indirect, on the district's population or population distribution as the additional workers needed during the construction phase are expected to come from the existing labor pool in the southern California area. Further, PAR 1110.2 is not expected to require a significant number of new permanent employees at each affected facility. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing PAR 1110.2. Accordingly, no significant adverse impacts on human population or housing are expected.

<u>Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect population and housing. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2</u>

engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse population and housing impacts significant.

Public Services

PAR 1110.2 is not expected to increase the need or demand for additional public services, e.g., fire departments, police departments, schools, parks, government, etc, above current levels. The proposed project is no expected to result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times or other performance objectives.

A comment was received during the public review period that stated that facilities may electrify and install diesel back-up generators to comply with PAR 1110.2. The commenter stated that because diesel fuel is stored in limited amounts PAR 1110.2 could impact fire fighting operations. For systems, such as water utilities, it is expected that operators would ensure the delivery of water during emergencies. SCAQMD staff expects that water agencies that electrify systems would use the existing natural gas engines as emergency back-up generators. Using the existing engines as emergency back-up generators would provide for the delivery of water during emergencies. The technology assessment in 2010 would also address safety issues and ensure that essential public services are safe guarded. Therefore, significant adverse impacts to public services are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect public resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse public resource impacts significant.

Recreation

As discussed under "Land Use" above, there are no provisions to the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments; no land use or planning requirements will be altered by the proposal. The proposed project would not increase the use of existing neighborhood and regional parks or other recreational facilities or include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment. Therefore, impacts to recreational facilities are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect recreational resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse recreational impacts significant.

Transportation/Traffic

PAR 1110.2 would generate additional construction and operational traffic. PAR 1110.2 would require the construction of additional monitoring and control equipment and infrastructure. PAR 1110.2 would require additional truck trips for source testing, spent catalyst removal, new catalyst delivery, ammonia delivery, and LNG haul trucks. A maximum of 62 truck trips per day is expected during construction at any facility. A maximum of 114 truck trips per day is expected during operation at any facility. Since facilities are scattered through out the SCAQMD and trips would be expected to be spread throughout the day, the overall adverse impact to traffic is expected to be minor. Therefore proposed project impacts from traffic are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since natural gas is supplied to existing sites through pipe lines, the exceptions would not affect transportation and traffic. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse transportation impacts significant.

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 aesthetics, air quality, energy hazards/hazardous materials and solid/hazardous waste as the environmental areas potentially adversely affected by the proposed project. The NOP/IS also identified solid/hazardous waste as significant, but after further analysis solid/hazardous waste was determined not to be significant.

Aesthetic significant adverse impacts can be considered irreversible since facility operators that install monitoring, emission control or ICE replacements are likely to operate with these systems for the lifetime of the equipment. Facility operators may replace these systems with similar systems.

Significant adverse impacts to air quality are not considered irreversible, since PAR 1110.2 is part of an AQMP, which overtime is designed to achieve attainment for criteria pollutants. Health risk from air toxics should be reduced overtime as clean, new engines replace older more polluting engine and diesel particulate control is added.

Significant adverse impacts from accidental releases of aqueous ammonia and LNG may be considered irreversible. As stated in the aesthetics discussion above, facility operators that install monitoring, emission control or ICE replacements are likely to operate with these systems for the lifetime of the equipment. Facility operators may replace these systems with similar systems. The delivery and storage of aqueous ammonia and LNG on-site would continue to have potential significant accidental release consequences.

POTENTIAL GROWTH-INDUCING IMPACTS

CEQA Guidelines §15126(d) requires an environmental analysis to consider the "growth-inducing impact of the proposed action." Implementing PAR 1110.2 would 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 commercial and industrial facilities. No additional workers are expected to be need at the affected facilities.

CONSISTENCY

The Southern California Association of Governments (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 PAR 1110.2 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. Based on the following discussion PAR 1110.2 is consistent with RCPG policies.

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. PAR 1110.2 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. Modifications to existing ICEs at affected facilities would likely be subject to permit modifications. The SCAQMD has implemented a series of actions over the six to eight years to streamline the SCAQMD permit process. As a result, PAR 1110.2 would 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 are 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 include 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 for developing sustainable communities and providing, 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 PAR 1110.2 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 would reduce exposure to seismic hazards, minimize earthquake damage, and develop emergency response and recovery plans. PAR 1110.2 would reduce NOx, CO and VOC emissions from ICEs and better monitor compliance. Therefore, in relation to the GMC, PAR 1110.2 is not expected to interfere with any air quality goals related to the GMC.

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

PAR 1110.2 is consistent with the RMP and CMP since no significant adverse impact to transportation/circulation would result from further control of NOx, CO and VOC from

ICEs. Since PAR 1110.2 is not expected to have a significant adverse impact on transportation/traffic, PAR 1110.2 is not expected to significantly adversely affect circulation patterns or congestion management.

CHAPTER 5

ALTERNATIVES

INTRODUCTION

This ~~Draft~~Final EA provides a discussion of a range of reasonable alternatives to the proposed project as required by state CEQA Guidelines §15126.6. Alternatives include measures for attaining objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. A "No Project" alternative must also be evaluated (CEQA Guidelines §15126.6(e)). The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. State 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.

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.

The Governing Board may choose to adopt any portion or all of any alternative presented below. The Governing Board is able to adopt any portion or all of any of the following alternatives because the impacts of each alternative are fully disclosed to the public and the public has the opportunity to comment on the alternatives and impacts generated by each alternative.

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)]. Because the scope of the current amendments is focused primarily on enhancing enforcement and obtaining further emission reductions through currently available control technologies and because there are a number options for reducing emissions from affected equipment, e.g., installing control equipment or replacing existing ICEs with alternative compliance technologies, no alternatives identified were rejected as infeasible.

DESCRIPTION OF ALTERNATIVES

The following proposed alternatives were developed by modifying specific components of the proposed amended rule. The rationale for selecting and modifying specific components of the proposed amended rule to generate feasible alternatives for the analysis is based on

CEQA's requirement to present "realistic" alternatives; that is, alternatives that can actually be implemented.

In addition to the No Project Alternative, the following three alternatives were developed by identifying and modifying major components of PR 1110.2. As stated in the Areas of Controversy section of Chapter 1, staff and stakeholders have been and are currently in discussions regarding specific provisions to be included in PAR 1110.2. Specifically, the primary components of the proposed alternatives that have been modified are the requirements related to emission concentration compliance limits for the three pollutants regulated by Rule 1110.2, efficiency correction for biogas combustion, source testing averaging times, compliance dates, natural life allowance, natural gas usage for biogas engines, and low usage exemptions. The alternatives, summarized in Table 5-1 and described in the following subsections, include the following: Alternative A (No Project); Alternative B (Low Use); and Alternative C (Enhanced Enforcement). Unless otherwise specifically noted, all other components of the project alternatives are identical to the components of PAR 1110.2. The following subsections provide a brief description of each project alternative and Table 5-1 summarizes the main components of each alternative.

Alternative A - No Project Alternative

Alternative A, the No Project Alternative, would mean not adopting PAR 1110.2 and, therefore, maintaining the existing emission compliance limits, CEMS requirements, source testing requirements, etc., of Rule 1110.2.

Alternative B – Low Use Alternative

PAR 1110.2 has an exception to concentration limits for non-biogas ICEs that are used less than 500 hours or that burn less than one billion Btu of fuel per year (high heating value). Alternative B, the Low Use Alternative, would expand the low use exception relative to complying with the proposed emission reduction requirements to non-biogas engines ICEs that are used less than 1,000 hours or that burn less than two billion Btu per year of fuel (high heating value). What this means is that the non-biogas engines that qualify for this exception would continue to comply with existing Rule 1110.2 NOx, VOC, and CO concentration requirements. This exception would apply to 32 additional engines.

The averaging time for PAR 1110.2 compliance limits is 15 minutes. Alternative B would also extend the averaging time from 15 minutes to one hour. Some affected facility operators have stated that existing control devices cannot meet the PAR 1110.2 compliance limits because of fluctuations in emissions and that a longer averaging time would prevent the need to replace existing control equipment with newer equipment for minor reductions in emissions. The averaging time component of Alternative B, therefore, responds to facility operators' comments regarding averaging times.

Table 5-1
Summary of PAR 1110.2 and Project Alternatives

Requirement	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Compliance Limits	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 70 ppm CO
Efficiency Correction for Biogas	No	Yes	No	No	No
Averaging Times	15 min	15 min	1 hour	15 min	15 min
Compliance Dates	Emission limits 2010 - 2012 Monitoring 2008 - 2010	N/A	Emission limits 2010 - 2012 Monitoring 2008 - 2010	Monitoring 2008 - 2010	Emission limits 2012 - 2014 Monitoring 2008 - 2010
Natural Life Allowance	None	N/A	None	None	Additional two years to comply with concentration limits
Natural Gas Percentage Limits	10	N/A	10	25	10
Low Usage Exception from Non-Biogas Compliance Limits	Less than 500 hours or less than 1,000 MMBtu annually	None	Less than 1,000 hours or less than 2,000 MMBtu annually	None	Same as PAR 1110.2

Table 5-1 (continued)
Summary of PAR 1110.2 and Project Alternatives

Requirement	**Proposed Project**	**Alternative A (No Project)**	**Alternative B (Low Use)**	**Alternative C (~~Compliance Only~~ Enhanced Compliance)**	**Alterative D (BACT)**
CEMS	Stationary ICE groups of 1,500 bhp ICEs or more included in CEMS unless < 500 bhp or operated <1,000 hr/yr or < 8 x 10^9 Btu/year	N/A	Same as PAR 11102, except lean-burn engines are exempt from CEMS requirements	Same as PAR 1110.2	Same as PAR 1110.2
Replacement of Existing ICE with Electric Motors	Voluntary	None	Voluntary	None	Mandatory

Similar to the proposed project, because Alternative B contains the same emission concentration requirements, SCAQMD staff expects that operators of the same categories of non-biogas engines would choose to replace existing engines with electric motors as a less costly compliance option.

Alternative B would include all of the CEMS requirements in the proposed project, but would add an exception that excludes lean-burn engines from the NOx CEMS requirements. It was estimated that the exception would apply to approximately nine facilities.

All other provisions of Alternative B are the same as PAR 1110.2, including compliance dates, reporting provisions, etc.

Alternative C – Enhanced Enforcement

Alternative C, the Enhanced Enforcement Alternative, would limit modifications to Rule 1110.2 to address compliance issues identified by SCAQMD inspectors. Similar to PAR 1110.2, to enhance enforcement, Alternative C would include the same: CEMs installation requirements in paragraph (e)(3); inspection and monitoring plan requirements in paragraph (e)(4); and monitoring, testing, recordkeeping, and reporting requirements; and reporting noncompliance requirements in subdivision (f). Alternative C would also eliminate the efficiency correction for biogas averaging times. No changes would be made to the existing compliance limits in Rule 1110.2. Replacement of non-biogas engines with electric motors is not expected under Alternative C.

Alternative C is considered to be the least toxic alternative for the following reasons. Although Alternative C would not generate emission reductions beyond what is currently required by Rule 1110.2, it will enhance enforcement of the rule to obtain emission reductions originally anticipated for the Rule. For example, as indicated in Chapter 3, during unannounced site visits and compliance tests, some engines were demonstrated to exceed existing emission concentrations in Rule 1110.2, some engines by a wide margin. Further, because Alternative C does not impose additional emission reduction requirements, it is not expected that add-on control would be installed, ICEs replaced with alternative technologies, or emergency engines installed. As a result, Alternative C would not result in new ammonia slip emissions or diesel exhaust particulate. Ammonia is not considered to be a carcinogen, it can have chronic and acute health impacts. Diesel particulate has both carcinogenic and chronic health affects.

Alternative D – Best Available Control Technology

Alternative D, the Best Available Control Technology (BACT) Alternative, would lower CO emission compliance limits to BACT emissions levels. The proposed emission compliance limits for NOx and VOC would be the same as for PAR 1110.2. With respect to emission compliance limits, Alternative D is similar to staff's initial proposal for PAR 1110.2, which also would have established compliance limits for CO at BACT emissions levels. Alternative D would include a useful life provision extending the final compliance dates for new concentration limits from 2012 to 2014 for biogas engines.

Alternative D would include a requirement that facility operators replace existing non-biogas engines with electric motors based on engine categories identified in Table 4-7, where it is expected that installing electric motors would be less costly than complying with the requirements of PAR 1110.2. An exception would be included that would allow facility operators to demonstrate to the Executive Officer other mitigating factors besides compliance/replacement costs that may prevent facility operators from replacing affected non-biogas engines with electric motors.

The comparison of the relative merits of the individual alternatives assumes that for Alternative D, operators of 169 non-biogas engines would install electric motors, while operators of the remaining 56 non-biogas engines would seek the exception to installing an electric motor due to unique operating conditions. It is assumed that the operators of the 56 non-biogas engine who do not install electric motors will comply with the proposed emission limits in this alternative. This assumption is consistent with the analysis of PAR 1110.2.

EVALUATION OF THE RELATIVE MERITS OF PROJECT ALTERNATIVES

Consistent with CEQA Guidelines §15126.6(a), the following subsections evaluate the relative merits of each project alternative. Potential adverse impacts for the environmental topics are quantified where sufficient data are available.

Alternative A - No Project Alternative

<u>Aesthetics</u>

Alternative A would not be expected to create significant adverse aesthetics impacts, because no construction or modification of process operations or procedures would be required.

<u>Air Quality</u>

Alternative A would not create significant adverse construction air quality impacts because no construction or modification of processes operations or procedures would be required. One of the primary reasons for amending Rule 1110.2 is to improve compliance with the emission concentrations of the rule by imposing CEMs requirements, inspection and monitoring plan requirements; monitoring, testing, recordkeeping, and reporting requirements; etc. By not amending Rule 1110.2, it is possible that a large number of affected engines would continue to operate out of compliance. As indicated in Table 5-2, engines exceeding compliance limits could do so in amounts that exceeds applicable SCAQMD significance thresholds. Therefore, it is concluded that Alternative A could create significant adverse operation air quality impacts. In addition, implementing Alternative A would not result in the CO2 emission reduction benefits anticipated for PAR 1110.2.

Table 5-2
Potential Emission Impacts in Violation of Rule 1110.2 from Implementing Alternative A

	NOx, lb/day	CO, lb/day	VOC, lb/day
Excess Emissions	9,195	54,243	2,517
Significance Thresholds	55	550	55
Significant	Yes	Yes	Yes

Energy

Alternative A would have no significant adverse diesel energy impacts, because no construction or modification of process operations or procedures would be required. Alternative A would not reduce electricity generation from existing engines that are retrofitted or replaced with less efficient energy generation equipment such as turbines, microturbines, etc., as would be the case under PAR 1110.2. Alternative A, however, would not provide the beneficial reduction in natural gas consumption that is anticipated under PAR 1110.2. Overall, Alternative A would not create any significant adverse energy impacts.

Hazards/Hazardous Materials

The analysis of potential hazard/hazardous materials impacts from implementing PAR 1110.2 in Chapter 4 concluded that the alternative compliance option of replacing existing biogas ICEs with biogas to LNG plants could produce significant adverse explosion and fire impacts to nearby receptors. Because Alternative A would impose no additional compliance requirements, it would not be expected to generate any significant adverse hazard impacts compared to PAR 1110.2.

Solid/Hazardous Waste

Chapter 4 concluded that, although there could be some solid waste impacts from disposal of ICE that are replaced with alternative compliance options and disposal of spent catalysts, local landfills and/or hazardous waste landfills in California could accommodate this increase in waste disposal. As a result, solid/hazardous waste impacts were concluded to be less than significant. Because Alternative A would impose no additional compliance requirements, it would not be expected to generate any significant adverse solid hazardous waste impacts compared to PAR 1110.2.

Alternative B – Low Use Alternative

Aesthetics

Alternative B would have similar adverse aesthetic impacts to PAR 1110.2. It is expected that Alternative B would generate fewer adverse aesthetic impacts for non-biogas facilities because the low use exception would capture fewer of these types of facilities and, as a result, operators of these facilities would not need to install control technology. However, Alternative B would have the same requirements for biogas facilities as PAR 1110.2. Since the analysis of PAR 1110.2 concluded that biogas facilities would potentially create the greatest adverse visual impacts from installing control systems (SCR, NOxTech, etc.) or ICE replacement systems (turbines, LNG plants, etc.), the worse-case adverse visual impacts for Alternative B would be equivalent to those identified for PAR 1110.2. Therefore, like PAR 1110.2, it is expected that Alternative B would generate significant adverse impacts on aesthetics.

Air Quality

Construction
Because the low use exception from further emission reduction requirements would be extended to non-biogas engines under Alternative B, it is anticipated that 11 fewer ICEs would need to be retrofitted with an oxidation catalyst and 30 few ICE would need to upgrade three-way catalyst. Alternative B would result in the installation of fewer catalysts; it is estimated to exclude eight facilities.

Alternative B would have an exception to the NOx CEMS requirements for lean-burn engines. The exception is expected to affect nine engines non-biogas at three facilities. Environmental analysis for Alternative B includes affects to direct emissions but to be conservative did not lessen secondary emissions (heavy-duty delivery trucks), hazard or solid/hazardous waste adverse impacts. The remaining facilities would be biogas facilities that would potential generate the largest construction emissions from the installation of add-on emission controls or replacement of the existing biogas engines with ICE alternative technologies (e.g., gas turbines, microturbines, LNG facilities, etc.).

Therefore these exceptions would likely have little effect on the number of construction projects on a typical day or, as a result, peak day construction emissions. Therefore, it assumed that the construction emissions for Alternative B would be approximately equivalent to those identified for PAR 1110.2.

Operational
Since Alternative B would reduce the number of non-biogas engines that would need to be retrofitted with three-way catalyst or oxidation catalysts upgrade, the emission reductions from Alternative B would be less than the proposed project. Fewer oxidation catalysts would also lead to fewer catalyst truck trips because smaller amounts of spent catalyst would be disposed of and fewer replacement catalysts would be needed.

Potential secondary air quality impacts identified for biogas engines are the same as the proposed project and include ammonia slip emissions from new SCR systems and additional truck trips for spent and replacement catalysts. ICE engines that are replaced with alternative control technologies would be expect to generate similar secondary air quality impacts to the proposed project.

The air quality effects of implementing Alternative B are presented in the same way as they were for PAR 1110.2. Tables 5-3 through 5-7 present the total emissions inventory by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with Alternative B and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. Table 5-3 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-4 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-5 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-6 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-7 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

A summary of operation emissions by biogas option are presented in Tables 5-3 through 5-7. Emission increases and emissions reductions from Alternative B are presented in Table 5-8 through 5-12.

Table 5-3
Net Criteria Emission Inventories from Non-biogas Facilities and the SCR Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ <u>9,094</u>	~~53,909~~ <u>53,942</u>	~~2,470~~ <u>2,479</u>	~~543.9~~ <u>545</u>	~~876.8~~ <u>878</u>	~~874.7~~ <u>876</u>
2009	~~6,410~~ <u>6,415</u>	~~22,399~~ <u>22,432</u>	~~1,790~~ <u>1,799</u>	~~543~~ <u>544</u>	~~858~~ <u>859</u>	~~856~~ <u>857</u>
2010	~~6,004~~ <u>6,009</u>	~~17,385~~ <u>17,418</u>	~~1,297~~ <u>1,306</u>	~~534~~ <u>535</u>	~~844~~ <u>845</u>	~~842~~ <u>843</u>
2011	~~5,595~~ <u>5,600</u>	~~13,617~~ <u>13,650</u>	~~1,240~~ <u>1,249</u>	~~529~~ <u>530</u>	~~834~~ <u>835</u>	~~831~~ <u>832</u>
2012	4,181	13,481	1,020	538	833	831
2014	4,188	13,477	1,018	538	833	831

Table 5-4
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	4,882	7,416	542	538	1,019	1,017
2014	4,888	7,412	540	538	1,019	1,017

Table 5-5
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbine Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	3,917	6,228	647	538	760	758
2014	3,923	6,224	645	538	760	758

Table 5-6
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,746	6,746	586	211	911	896
2014	4,377	6,576	535	211	878	876

Table 5-7
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,362	6,281	632	211	805	791
2014	3,993	6,111	581	211	773	771

Table 5-8 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-9 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-10 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-11 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-12 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-8
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,600)~~ (3,594)	~~(40,626)~~ (40,593)	~~(1,253)~~ (1,244)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)
2012	(5,013)	(40,762)	(1,473)	(13)	(44)	(44)
2014	(5,007)	(40,766)	(1,475)	(13)	(44)	(44)

Numbers in parentheses represent emission reductions.

Table 5-9
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,253)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(4,313)	(46,827)	(1,951)	(13)	142	142
2014	(4,307)	(46,831)	(1,953)	(13)	142	142

Numbers in parentheses represent emission reductions.

Table 5-10
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,254)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(5,278)	(48,015)	(1,846)	(13)	(117)	(117)
2014	(5,272)	(48,019)	(1,848)	(13)	(117)	(117)

Numbers in parentheses represent emission reductions.

Table 5-11
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(4,449)	(47,497)	(1,907)	(340)	33.6	21.28
2014	(4,818)	(47,667)	(1,957)	(340)	1.2	0.73

Numbers in parentheses represent emission reductions.

Table 5-12
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(4,833)	(47,962)	(1,861)	(340)	(72)	(84)
2014	(5,202)	(48,132)	(1,912)	(340)	(104)	(104)

Numbers in parentheses represent emission reductions.

As is the case with PAR 1110.2, the worst-case emissions from Alternative B would occur if all biogas operators replace existing ICEs with gas turbines. PM2.5 emissions would exceed the PM2.5 significance threshold of 55 pounds per day if facilities replace ICEs with gas turbines (142 pounds per day).

Similar to the air quality analysis for PAR 1110.2, the air quality analysis for Alternative B includes the assumption that operators of 169 non-biogas engines would replace existing engines with electric motors. Based on this assumption, it is expected that Alternative B would also reduce CO2 emissions. Similar to PAR 1110.2, Alternative B would require a technology assessment, but it would be required in 2012 instead of 2010. The technology assessment would include the number of non-biogas engines that have been replaced with electric motors. As with PAR 1110.2, any shortfalls in CO2 emission reductions would be made up by other measures identified at the time the technology assessment is completed. For overall CO2 reductions, approximately 14 engines would need to be replaced. Table 5-13 summarizes the overall CO2 reduction analysis.

Table 5-13
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under Alternative B

Description	Proposed Project CO2, ton/10 years	No Electrification CO2, ton/10 years	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
SCR	(264,959)	11,516	276,475	1,636	8
Replace ICE with Gas Turbine	(104,642)	9,157	113,799	673	14
Replace ICE Microturbine	(266,520)	9,955	276,475	1,636	7
Replace LFG w LNG, DG w Turbines	(1,228,165)	(951,690)	276,475	1,636	0
Replace LFG w LNG, DG w Microturbines	(1,227,406)	(950,932)	276,475	1,636	0

Electric motors were assumed to have a ten year lifespan.

Energy

Expanding the low use exception would reduce the number of engines that would need to be retrofitted with oxidation catalyst. The exception of lean-burn engines from the NOx CEMS requirements would reduce the amount of electricity required to operate CEMS at seven facilities. This aspect of Alternative B is not expected to change the magnitude of adverse energy impacts previously identified for PAR 1110.2. There would be an incremental reduction in the amount of diesel fuel required for catalyst disposal and replacement trips because fewer engines would be retrofitted with oxidation catalysts. As indicated in the analysis of PAR 1110.2, most of the adverse energy impacts are anticipated as a result of modifications at biogas facilities. Because the concentration provision in Alternative B is identical to the concentration provision in PAR 1110.2, potential adverse energy impacts from compliance activities at biogas facilities would be similar to those identified for PAR 1110.2. Potential adverse energy impacts include increased demand for diesel resulting from truck trips associated with removal and replacement of catalysts and ammonia delivery. Alternative B would allow the same compliance options at biogas facilities that are available for PAR 1110.2. As a result, Alternative B would generate energy impacts equivalent to PAR 1110.2. Like PAR 1110.2 Alternative B would increase demand for electricity, while reducing demand for natural gas. Further, losses of renewable energy in one sector would be made up by increases in renewable energy in another sector. Therefore, overall Alternative B, like PAR 1110.2, is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

Hazards and hazardous materials impacts identified for PAR 1110.2 were associated with compliance activities at biogas facilities. Because Alternative B was analyzed using the same compliance scenarios as PAR 1110.2, hazard/hazardous materials impacts would be equivalent to those identified for PAR 1110.2. Secondary hazards and hazardous materials impacts are associated only with control technologies (in particular retrofitting engines with SCR or replacing engines with LNG plants) expected to be used at biogas facilities.

Biogas facilities that install SCR or NOxTech systems would have potential adverse impacts from ammonia accidental releases. The furthest distance to the significant threshold ERPG2 concentration of 150 ppm of ammonia modeled would be 0.1 miles from the catastrophic failure of an ammonia storage tank. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. For the off-site impacts analysis, it was assumed that ammonia storage tanks would be constructed close to where existing ICE is located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with ammonia tanks that are less than 0.1 miles from the property line. Some facilities have sensitive receptors within 0.1 miles of ammonia storage sites; therefore Alterantive B is significant for accidental releases from ammonia storage.

The transport of aqueous ammonia is not likely to significantly impact receptors because conditions are not typically that would result in pooling of the aqueous ammonia. For example, an accidental release of aqueous ammonia on roadways is unlikely to result in pooling as there are no barriers to impede flow, so it would likely flow off roads onto porous ground where it would be absorbed or underground into storm drains.

Biogas facilities operators who install LNG plants would have potential adverse impacts from LNG accidental releases. The furthest distance to the significance threshold of one psi overpressure is 0.2 mile. One psi overpressure may cause partial demolition of houses, shattering of glass windows and serious injuries to people. For the off-site impacts analysis, it was assumed that LNG storage tanks would be constructed close to where the existing ICEs are located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with LNG tanks that are less than 0.1 mile from the property line. Therefore, facility operators who choose to replace ICEs with biogas to LNG plants could create significant adverse impacts to receptors within 0.2 mile of the LNG storage tanks.

No facilities have schools within one-quarter mile; therefore, Alternative D would not significantly adversely affect schools within a quarter mile. No facilities are within two miles of an airport or airfield; therefore, would not adversely significantly impact those working at or near an airport or airfield. However, facilities would have sensitive receptors within 0.2 mile of LNG storage sites. No mitigation measures were identified that could reduce this potential adverse hazard impact to less than significant.

During transport, LNG is compressed by refrigeration, and it is not flammable in its liquid state. However, an accident could produce a pool of LNG that could evaporate and ignite, forming a flammable cloud, BLEVE, or a ruptured tank could rocket away and ignite. Receptors within 0.3 mile of the delivery truck may be adversely affected by any of these scenarios. A tank that ruptures and rockets away could adversely affect a zone covering greater than 0.3 mile around the tank from the initial accident site to the final resting place of the LNG delivery tank. Therefore, Alternative B is considered significant for accidental releases of LNG during transport.

Solid/Hazardous Waste

It is anticipated that Alternative B would generate less solid/hazardous wastes then PAR 1110.2, because fewer oxidation catalysts would be installed as a result of the compliance exception extended to non-biogas facilities. Metals from oxidation catalysts may be recycled, but eventually would become waste. While it is assumed that oxidation catalysts would be considered "designated waste" that can be disposed of in Class II or III landfills, some oxidation catalyst may be classified as hazardous waste requiring disposal in Class I landfills.

Similar to the analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all biogas ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative B.

It is expected that Alternative B would generate incrementally less solid/hazardous waste impacts than PAR 1110.2 because of the exception applied to non-biogas engines. Overall Alternative B, like PAR 1110.2, is not expected to generate significant adverse solid/hazardous waste impacts.

Alternative C – Enhanced Enforcement Alternative

Aesthetics

Alternative C would maintain the same pollution control requirements that are currently in Rule 1110.2. As a result, Alternative C would not substantially change the size or configuration of existing engines onsite. Alternative C, like PAR 1110.2 would require operators of specified categories of ICEs to install CEMs, requiring minor construction at affected facilities. Neither the construction of CEMs nor operation of this equipment is expected to change the visual character of affected facilities. Alternative C would likely require additional infrastructure for source testing and additional monitoring equipment. The additional infrastructure and monitoring equipment is also not expected to change the visual character of the affected facilities or surroundings. Therefore, Alternative C, like PAR 1110.2, is not expected to create significant adverse aesthetics impacts. Aesthetics impacts from implementing Alternative C would be less than for PAR 1110.2 since alternative compliance options that may occur under PAR 1110.2 may be slightly more noticeable.

Air Quality

Because Alternative C does not impose additional concentration limit requirements like the proposed project and other alternatives, but does impose measures such as installation of CEMs, potential air quality impacts from construction activities would be substantially less than for the proposed project. Relative to operational activities, Alternative C is expected to generate emission reductions compared to the baseline inventory by enhancing enforcement of the existing emission control requirements through installation of CEMs, additional inspection and monitoring, etc. Alternative C, however, may generate diesel exhaust emission during operation from source testing vehicle trips (source testing vehicles may be gasoline powered). However, SCAQMD staff expects only one additional source test per facility every two years. Health risk from a single vehicle trip every other year would be negligible.

Table 5-14 presents the inventory of emissions from all engines that would be subject to Alternative C by year in which different requirements become effective. As with PAR 1110.2, construction and operational emissions are expected to overlap. Table 5-15 shows the net effect on emissions from affected engines, taking into consideration both construction emission increases and emission reductions anticipated from enhanced enforcement activities.

Table 5-14
Total Emissions Inventory by Year
Anticipated from Implementing Alternative C

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,152~~ 9,155	~~54,086~~ 54,104	~~2,489~~ 2,494	~~547~~ 547	~~880.8~~ 881.3	~~878.6~~ 879.1	~~1,237,862~~
2009	~~6,853~~ 6,856	~~22,683~~ 22,701	~~1,848~~ 1,853	~~547~~ 547	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,246,022~~
2010	~~6,864~~ 6,867	~~22,233~~ 22,251	~~1,519~~ 1,524	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,803~~
2011	~~6,820~~ 6,823	~~21,989~~ 22,007	~~1,517~~ 1,522	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,875~~

As indicated in Table 5-15, Alternative C is not expected to create significant averse air quality impacts. As already noted in the project description for Alternative C, since Alternative C does not include additional emission control requirements that could result in retrofitting existing engines with SCR, no ammonia slip emissions would be generated. Consequently, Alternative is concluded to be the least toxic alternative.

Energy

Alternative C would have minor adverse energy impacts, from additional monitoring equipment and vehicle travel associated with additional source testing. Approximately 567 MW-hours per year would be required for CEMS, ATRC and analyzers. Based on the available 120,194 GW-hours per year in southern California, this would be less than one percent of the available electricity ($4.73x10^{-7}$ percent).

Table 5-15
Net Emissions Effect from Implementing Alternative C
Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(43)~~ (40)	~~(157)~~ (139)	~~(3)~~ 1	~~(5)~~ (4)	~~3.9~~ 4.4	~~3.4~~ 3.9	~~(12,184)~~
2009	~~(2,331)~~ (2,339)	~~(32,010)~~ (31,542)	~~(974)~~ (640)	~~(6)~~ (4)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2010	~~(2,331)~~ (2,328)	~~(32,010)~~ (31,992)	~~(974)~~ (969)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2011	~~(2,375)~~ (2,372)	~~(32,254)~~ (32,236)	~~(976)~~ (971)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,172)~~

Numbers in parentheses represent emission reductions.

Since Alternative C would not require emissions control equipment, it would not affect electrical production at biogas facilities. Since it would not affect electrical production at biogas facilities it would not affect renewable energy goals.

Alternative C has a higher natural gas allowance in connection with the combustion of biogas or digester gas compared to PAR 1110.2, 25 percent versus 10 percent respectively. As a result, Alternative C is not expected to reduce natural gas usage at affected biogas facilities as would be the case under PAR 1110.2. Regardless of this effect and, based on the above analysis, Alternative C is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

The analysis of potential hazard/hazardous materials impacts from implementing PAR 1110.2 in Chapter 4 concluded that the alternative compliance option of replacing existing biogas ICEs with biogas to LNG plants could produce significant adverse explosion and fire impacts to nearby receptors. Because Alternative C would impose no additional compliance requirements, it would not be expected to generate any significant adverse hazard impacts compared to PAR 1110.2. Further, hazards would not be generated from increased monitoring and source testing. Therefore, Alternative C is not expected to create significant adverse hazards/hazardous materials impacts.

Solid/Hazardous Waste

Chapter 4 concluded that, although there could be some solid waste impacts from disposal of ICE that are replaced with alternative compliance options and disposal of spent catalysts, local landfills and/or hazardous waste landfills in California could accommodate this increase in waste disposal. As a result, solid/hazardous waste impacts were concluded to be less than significant. Because Alternative C would impose no additional compliance requirements and no additional solid or hazardous waste would be generated from increased monitoring and source testing, Alternative C would not be expected to generate any significant adverse solid or hazardous waste impacts compared to PAR 1110.2.

Alternative D – BACT Alternative

Aesthetics

Alternative D would have similar adverse aesthetic impacts to PAR 1110.2. Alternative D may have incrementally greater adverse visual impacts at both non-biogas and biogas facilities, because the lower CO compliance limit may require larger control units at affected facilities. While CO control equipment may be physically larger, they would generally have the same visual characteristics and, therefore, would be indistinguishable from the units used to comply with PAR 1110.2. It is possible that there may be additional costs associated with controlling CO emissions to a lower concentration and, as a result, could create a greater impetus for operators to replace ICEs with alternative systems. However, the analysis of impacts from implementing PAR 1110.2 already assumed that operators of all affected biogas engines would replace ICEs with alternative systems. This same assumption would apply to Alternative D as a worst-case. Therefore, since the worst-case scenarios for PAR 1110.2 and Alternative D are the same, the worst-case adverse impacts are considered to be equivalent. For example, under either PAR 1110.2 or Alternative D operators of biogas engines could potentially retrofit engines with control systems (SCR, NOxTech, etc.) or replace ICEs with alternative compliance options (microturbines, turbines, or biogas LNG plants). As a result, the worse-case adverse impacts from implementing Alternative D would be similar those identified from implementing PAR 1110.2. Therefore, it is concluded that Alternative D could create potentially significant adverse aesthetics impacts.

Air Quality

Construction

Alternative D would likely require more construction than PAR 1110.2, since Alternative D does not include a low usage exemption from compliance limits, but does require a lower CO compliance limit of 70 ppm than PAR 1110.2 (250 ppm). However, Alternative D would add an additional two years to the compliance dates proposed in PAR 1110.2. Operators who have existing equipment that is less than 10 years old in 2008 would receive an additional two years to comply with the proposed emission concentration requirements. An additional two years to comply with the final concentration requirements would result in fewer construction activities overlapping, thus, potentially reducing peak day construction impacts compared to PAR 1110.2.

Operational

Alternative D would generate the same NOx and VOC emission reductions as PAR 1110.2, but is expected to achieve greater CO emission reductions than PAR 1110.2 because the CO compliance limit under Alternative D is 70 ppm, which is lower than the CO limit for PAR 1110.2. The control technologies used to reduce NOx and VOC emissions will also reduce CO emissions. It is expected that these technologies would reduce CO to 70 ppm; however, facility operators have stated that it would be difficult to keep all three pollutants under the compliance limits of Alternative D.

Since CO is a product of incomplete combustion, the lower CO concentration compliance limit may generate greater CO2 emissions. Assuming that the same number of non-biogas engines are replaced with electric motors as would be the case under PAR 1110.2, CO2 emission reduction benefits under Alternative would be less than anticipated under PAR 1110.2.

Because the final biogas concentration limit compliance dates for Alternative D are delayed by two years with the natural life allowance compared to PAR 1110.2, anticipated emission reductions would occur later. Allowing an additional two years to comply with the emission concentration requirements in Alternative D may allow the emergence of new air pollution control technologies that are more efficient and with fewer secondary impacts than currently available control technologies. Such advances in technology are not currently reasonably foreseeable and, as a result, the analysis of impacts for Alternative D assumes the same technologies will be used as under PAR 1110.2.

The air quality effects of implementing Alternative D are presented in the same way as they were for PAR 1110.2. Tables 5-16 through 5-20 present the total emissions inventory by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with Alternative D and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. Table 5-16 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-17 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-18 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-19 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-20 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-16
Net Criteria Emission Inventories from Non-biogas Facilities and the SCR Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,591~~ 5,596	~~11,733~~ 11,766	~~1,200~~ 1,209	~~529~~ 530	~~834~~ 835	~~831~~ 832
2012	5,420	11,657	1,177	528	825	823
2014	3,706	3,504	425	74	697	696
2015	3,712	3,500	423	74	697	696

Table 5-17
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~11,731~~ 11,764	~~1,199~~ 1,208	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	5,444	11,784	1,189	529	832	830
2014	4,878	5,532	502	538	1,019	1,017
2015	4,884	5,527	500	538	1,019	1,017

Table 5-18
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbine Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ <u>9,094</u>	~~53,909~~ <u>53,942</u>	~~2,470~~ <u>2,479</u>	~~543.9~~ <u>545</u>	~~876.8~~ <u>878</u>	~~874.7~~ <u>876</u>
2009	~~6,410~~ <u>6,415</u>	~~22,399~~ <u>22,432</u>	~~1,790~~ <u>1,799</u>	~~543~~ <u>544</u>	~~858~~ <u>859</u>	~~856~~ <u>857</u>
2010	~~5,964~~ <u>5,969</u>	~~15,818~~ <u>15,851</u>	~~1,267~~ <u>1,276</u>	~~534~~ <u>535</u>	~~844~~ <u>845</u>	~~842~~ <u>843</u>
2011	~~5,586~~ <u>5,591</u>	~~11,731~~ <u>11,764</u>	~~1,199~~ <u>1,208</u>	~~529~~ <u>530</u>	~~833~~ <u>834</u>	~~831~~ <u>832</u>
2012	5,463	11,854	1,196	529	837	835
2014	3,913	4,344	607	538	760	758
2015	3,919	4,339	605	538	760	758

Table 5-19
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities Under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ <u>9,094</u>	~~53,909~~ <u>53,942</u>	~~2,470~~ <u>2,479</u>	~~543.9~~ <u>545</u>	~~876.8~~ <u>878</u>	~~874.7~~ <u>876</u>
2009	~~6,410~~ <u>6,415</u>	~~22,399~~ <u>22,432</u>	~~1,790~~ <u>1,799</u>	~~543~~ <u>544</u>	~~858~~ <u>859</u>	~~856~~ <u>857</u>
2010	~~5,964~~ <u>5,969</u>	~~15,818~~ <u>15,851</u>	~~1,267~~ <u>1,276</u>	~~534~~ <u>535</u>	~~844~~ <u>845</u>	~~842~~ <u>843</u>
2011	~~6,072~~ <u>6,077</u>	~~11,931~~ <u>11,964</u>	~~1,257~~ <u>1,266</u>	~~529~~ <u>530</u>	~~872~~ <u>873</u>	~~857~~ <u>858</u>
2012	5,944	12,230	1,267	529	896	882
2014	4,742	4,862	546	211	911	896
2015	4,373	4,692	495	211	878	876

Table 5-20
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~11,931~~ 11,964	~~1,257~~ 1,266	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	5,963	12,280	1,272	529	899	885
2014	4,206	3,707	483	75	736	722
2015	3,837	3,537	433	74	703	702

Table 5-21 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-22 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-23 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-24 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-25 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-21
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ <u>(100)</u>	~~(334)~~ <u>(301)</u>	~~(22)~~ <u>(14)</u>	~~(7.5)~~ <u>(6.9)</u>	~~(0.1)~~ <u>0.8</u>	~~0.4~~ <u>0.4</u>
2009	~~(3,231)~~ <u>(3,225)</u>	~~(38,425)~~ <u>(38,392)</u>	~~(1,226)~~ <u>(1,217)</u>	~~(18)~~ <u>(17)</u>	~~(33)~~ <u>(32)</u>	~~(33)~~ <u>(32)</u>
2010	~~(3,231)~~ <u>(3,225)</u>	~~(38,425)~~ <u>(38,392)</u>	~~(1,226)~~ <u>(1,217)</u>	~~(18)~~ <u>(17)</u>	~~(33)~~ <u>(32)</u>	~~(33)~~ <u>(32)</u>
2011	~~(3,603)~~ <u>(3,598)</u>	~~(42,510)~~ <u>(42,477)</u>	~~(1,293)~~ <u>(1,284)</u>	~~(23)~~ <u>(22)</u>	~~(43)~~ <u>(42)</u>	~~(44)~~ <u>(43)</u>
2012	(3,775)	(42,586)	(1,315)	(23)	(52)	(52)
2014	(5,489)	(50,739)	(2,068)	(477)	(180)	(180)
2015	(5,483)	(50,743)	(2,070)	(477)	(179)	(179)

Numbers in parentheses represent emission reduction.

Table 5-22
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ <u>(100)</u>	~~(334)~~ <u>(301)</u>	~~(23)~~ <u>(14)</u>	~~(7.5)~~ <u>(6.9)</u>	~~(0.1)~~ <u>0.8</u>	~~0.4~~ <u>0.4</u>
2009	~~(3,231)~~ <u>(3,225)</u>	~~(38,425)~~ <u>(38,392)</u>	~~(1,194)~~ <u>(1,217)</u>	~~(18)~~ <u>(17)</u>	~~(33)~~ <u>(32)</u>	~~(33)~~ <u>(32)</u>
2010	~~(3,231)~~ <u>(3,225)</u>	~~(38,425)~~ <u>(38,392)</u>	~~(1,226)~~ <u>(1,217)</u>	~~(18)~~ <u>(17)</u>	~~(33)~~ <u>(32)</u>	~~(33)~~ <u>(32)</u>
2011	~~(3,609)~~ <u>(3,603)</u>	~~(42,512)~~ <u>(42,479)</u>	~~(1,294)~~ <u>(1,285)</u>	~~(23)~~ <u>(22)</u>	~~(43)~~ <u>(43)</u>	~~(44)~~ <u>(43)</u>
2012	(3,751)	(42,459)	(1,304)	(23)	(44)	(45)
2014	(4,317)	(48,711)	(1,991)	(13)	142	142
2015	(4,311)	(48,716)	(1,993)	(13)	142	142

Numbers in parentheses represent emission reduction.

Table 5-23
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,609)~~ (3,603)	~~(42,512)~~ (42,479)	~~(1,294)~~ (1,285)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(3,732)	(49,389)	(1,297)	(22)	(40)	(40)
2014	(5,282)	(49,899)	(1,886)	(13)	(117)	(117)
2015	(5,275)	(49,904)	(1,888)	(13)	(117)	(117)

Numbers in parentheses represent emission reduction.

Table 5-24
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(3,251)	(42,013)	(1,226)	(22)	19.6	7.24
2014	(4,453)	(49,381)	(1,947)	(340)	33.7	21.30
2015	(4,821)	(49,551)	(1,998)	(340)	1.2	0.75

Numbers in parentheses represent emission reduction.

Table 5-25
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(3,232)	(41,963)	(1,220)	(22)	22	10
2014	(4,989)	(50,536)	(2,009)	(477)	(141)	(153)
2015	(5,358)	(50,706)	(2,060)	(477)	(173)	(174)

Numbers in parentheses represent emission reduction.

As can be seen in Table 5-22, the worst-case operational emissions scenario would be if all biogas operators replace ICEs with gas turbines. In this scenario, PM2.5 emissions exceed the applicable operational significance threshold. No other compliance scenarios resulted in significant adverse air quality impacts. Air quality impact conclusions for Alternative D are the same as the air quality impact conclusions for PAR 1110.2.

Similar to the air quality analysis for PAR 1110.2, the air quality analysis for Alternative D includes the assumption that operators of 169 non-biogas engines would replace existing engines with electric motors. Based on this assumption, it is expected that Alternative D would also reduce CO2 emissions. Similar to PAR 1110.2, Alternative D would require a technology assessment, but it would be required in 2012 instead of 2010. The technology assessment would include the number of non-biogas engines that have been replaced with electric motors. As with PAR 1110.2, any shortfalls in CO2 emission reductions would be made up by other measures identified at the time the technology assessment is completed and presented to the Governing Board. For overall CO2 reductions, approximately 27 engines would need to be replaced. Table 5-26 summarizes the overall CO2 reduction analysis.

Table 5-26
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under Alternative D

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
SCR	(248,723)	32,719	281,443	1,665	20
Replace ICE with Gas Turbine	(100,168)	18,664	118,831	703	27
Replace ICE Microturbine	(261,981)	19,462	281,443	1,665	12
Replace LFG w LNG, DG w Turbines	(1,223,610)	(942,167)	281,443	1,665	0
Replace LFG w LNG, DG w Microturbines	(1,222,851)	(941,408)	281,443	1,665	0

Electric motors were assumed to have a ten year lifespan.
Numbers in parentheses represent emission reductions.

Energy

In practice, more biogas facility operators may replace ICEs with alternative compliance technologies such as boilers, turbines, microturbines, electrification, and biogas to LNG plants under Alternative D than PAR 1110.2. However, because actual compliance options were not known and to provide a conservative analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative D. As a result, Alternative D would generate energy impacts similar to PAR 1110.2. Like PAR 1110.2 Alternative D would increase demand for electricity, while reducing demand for natural gas. Further, losses of renewable energy in one sector would be made up by increases in renewable energy in another sector. Therefore, overall Alternative D, like PAR 1110.2, is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

Because Alternative D was analyzed using the same compliance scenarios as PAR 1110.2, hazard/hazardous materials impacts would be equivalent to those identified for PAR 1110.2. ICEs at non-biogas facilities would only require monitoring equipment or oxidation catalysts. Neither of these compliance requirements at non-biogas facilities includes use of hazardous materials that would adversely affect the public. Secondary hazards and hazardous materials impacts are associated only with control technologies (in particular retrofitting engines with SCR or replacing engines with LNG plants) expected to be used at biogas facilities.

Biogas facility operators could install SCR on existing ICEs or replace ICEs with biogas to LNG plants under either Alternative D or PAR 1110.2. The furthest distance to the significant threshold ERPG2 concentration of 150 ppm of ammonia modeled would be 0.1 miles from the catastrophic failure of an ammonia storage tank. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. Ammonia storage tanks if installed within 0.1 mile of the property boundary may significantly adversely impact sensitive or residential receptors within 0.1 mile of a catastrophic accidental failure of the ammonia storage tank.

The transport of aqueous ammonia is not likely to significantly impact receptors because conditions are not typically that would result in pooling of the aqueous ammonia. For example, an accidental release of aqueous ammonia on roadways is unlikely to result in pooling as there are no barriers to impede flow, so it would likely flow off roads onto porous ground where it would be absorbed or underground into storm drains.

Biogas facilities operators who install LNG plants would have potential adverse impacts from LNG accidental releases. The furthest distance to the significance threshold of one psi overpressure is 0.2 mile. One psi overpressure may cause partial demolition of houses, shattering of glass windows and serious injuries to people. For the off-site impacts analysis, it was assumed that LNG storage tanks would be constructed close to where the existing ICEs are located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with LNG tanks that are less than 0.1 mile from the property line. Therefore, facility operators who choose to replace ICEs with biogas to LNG plants could create significant adverse impacts to receptors within 0.2 mile of the LNG storage tanks.

No facilities have schools within one-quarter mile; therefore, Alternative D would not significantly adversely affect schools within a quarter mile. No facilities are within two miles of an airport or airfield; therefore, would not adversely significantly impact those working at or near an airport or airfield. However, facilities would have sensitive receptors within 0.2 mile of LNG storage sites. No mitigation measures were identified that could reduce this potential adverse hazard impact to less than significant.

During transport, LNG is compressed by refrigeration, and it is not flammable in its liquid state. However, an accident could produce a pool of LNG that could evaporate and ignite, forming a flammable cloud, BLEVE, or a ruptured tank could rocket away and ignite. Receptors within 0.3 mile of the delivery truck may be adversely affected by any of these scenarios. A tank that ruptures and rockets away could adversely affect a zone covering greater than 0.3 mile around the tank from the initial accident site to the final resting place of the LNG delivery tank. Therefore, Alternative D is considered significant for accidental releases of LNG during transport.

Solid/Hazardous Waste

The replacement or installation of oxidation catalyst for non-biogas facilities would be the same for Alternative D and the existing project. However, in practice, more biogas facility operators may replace ICEs with alternative compliance technologies such as boilers, turbines, microturbines, electrification, and biogas to LNG plants under Alternative D than

PAR 1110.2. Because actual compliance options were not known and to provide a conservative analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all biogas ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative D. As a result, Alternative D would generate solid/hazardous waste impacts equivalent to PAR 1110.2. Overall Alternative D, like PAR 1110.2, is not expected to generate significant adverse solid/hazardous waste impacts.

Comparison of the Relative Merits of the Project Alternatives by Environmental Topic

The following subsections summarize the effects of PAR 1110.2 and the project alternatives by environmental category.

Aesthetics

Alternative A would not be expected to generate any aesthetics impacts because it would not require any additional emission reductions or compliance modifications. Of the remaining alternatives, Alternative C is expected to generate less than significant aesthetic impacts because it only requires the addition of source testing infrastructure, CEMS, ATRCs and analyzers. The analysis of PAR 1110.2 concluded that it has the potential to generate significant adverse aesthetics impacts primarily from removal of ICEs and the installation of alternative technologies at biogas facilities. Because Alternatives B and D contain the same requirements as PAR 1110.2 for engines at biogas facilities, they would be expected to create significant adverse aesthetics impacts equivalent to PAR 1110.2.

Air Quality

Although Alternative D would generate the same NOx and VOC emission reductions as PAR 1110.2, Alternative D would generate more CO emission reductions than PAR 1110.2 because of the lower CO compliance limit (Table 5-27). Because Alternative B would extend the compliance exception for non-biogas engines, it would generate more emissions than PAR 1110.2. Alternative C does not contain any emission reduction requirements and, as a result, would generate as much emission reductions as the proposed project and other alternatives. However, because of the enforcement enhancements contained in Alterative C, it is expected to prevent or limit future violations of the existing emission concentration requirements in Rule 1110.2. Alternative A would have the least beneficial effect on air quality because, not only would it not produce any emission reductions, it contains no enhanced enforcement provisions that reduce future violations of the exiting provisions in Rule 1110.2. The emissions in Table 5-27 represent the net effects of both construction emission increases, secondary operational emission increase impacts, and direct emission reductions from each potential project.

Table 5-27
Worst-Case Emissions Increases or Reductions from Each Alternative

Description	Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Proposed Project	2014	(5,433)	(46,868)	(1,955)	(13.0)	142	142
Alternative A*	-	0	0	0	0	0	0
Alternative B	2014	(4,307)	(46,831)	(1,953)	(13.0)	142	142
Alternative C	2011	(43)	(157)	(3.3)	(4.7)	3.9	3.4
Alternative D	2015	(4,311)	(48,716)	(1,993)	(13.0)	142	142

Numbers in parentheses represent emission reductions.
* Estimated excess emissions over the current Rule 1110.2 are reported for Alternative A.

Toxic Air Contaminate Emissions

Alternative A is not expected to generate any addition air toxics because imposes no additional requirements for affected engines. Alternative C would generate negligible (less than significant) cancer risks from diesel particulate exhaust from trucks used to visit sites for source testing. The reason for this conclusion is that increased source testing would add one additional trip to affected facilities every two years. The analysis of PAR 1110.2 concluded that the proposed project could generate significant adverse cancer risk impacts at biogas and non-biogas facilities where operators install emergency backup diesel engines. Cancer risk impacts from Alternatives B and D are expected to be equivalent to PAR 1110.2, since operators at the same biogas and non-biogas facility may install diesel emergency backup generators because existing ICEs may be replace with alternative compliance options (e.g., LNG plants that also generate truck trips to pick up LNG).

Greenhouse Gas Emissions

Neither Alternative A nor Alternative C is expected to reduce CO2 emissions. Because the same assumptions were used for PAR 1110.2 and Alternative B regarding the number non-biogas engines that would be replaced with electric motors and because secondary CO2 emissions from construction equipment anticipated for these two alternatives are expected to be equivalent, both PAR 1110.2 and Alternative B are expected to generate similar CO2 emission reductions. Alternative D could potentially generate greater CO2 emissions reductions based on mandatory replacement of existing non-biogas ICEs with electric motors for those engine categories identified were compliance would be less costly than retrofitting existing engines. It is anticipated, however, that Alternative D would generate lower CO2 emission reductions than the proposed project, because it would implement a lower CO concentration requirement. Reducing CO emissions using an oxidation catalyst increases CO2 emissions.

The technology assessment required for PAR 1110.2 and all alternatives (except Alternative A) would verify the actual number of non-biogas engines replaced with electric motors and associated CO2 emission reductions. Any CO2 emission reduction shortfalls are expected to be made up through other CO2 emission reduction programs.

Hazards/Hazardous Materials

Neither Alternative A nor Alternative C would require the use of hazardous materials that could generate significant adverse hazard/hazardous materials impacts. The hazards analysis for PAR 1110.2 concluded significant adverse hazard impacts could occur at biogas facilities where operators retrofit existing equipment with SCR units or replace existing engines with LNG plants. For example, the toxic end point from aqueous ammonia would be 0.1 mile, which could expose receptors to ERPG 2 levels of ammonia, which is considered significant. Relative to LNG plants, the distance of a one psi shockwave from an LNG tank failure could be 0.2 mile. Adverse impacts from an accidental upset of an LNG truck could be up to 0.3 mile. Because receptors are expected to be located within these impact zones, this impact is considered to be significant. Because Alternatives B and D have the same requirements for biogas engines as PAR 1110.2, it is anticipated that hazard impacts under these alternatives would be equivalent to the proposed project. Similarly, the proposed project and Alternatives B and D may also generate significant adverse hazard impacts from the accidental upset of LNG transport trucks.

Solid/Hazardous Waste

Neither Alternative A nor Alternative C is expected to generate solid waste impacts. Alternative A imposes no additional requirements so no additional waste would be generated at affected facilities. Similarly, Alternative C does not contain any additional control requirements that would result in the generation of wastes. PAR 1110.2 and Alternatives B and D impose similar requirements that could generate additional wastes such as disposal of any existing emissions control equipment, catalyst, carbon, diesel fuel, etc. In spite of the potential for waste generation by PAR 1110.2 and Alternatives B and D, local or state landfills have the capacity to accommodate additional wastes produced by these proposals. Therefore, neither PAR 1110.2 nor any of the project alternatives have the potential to generate significant adverse solid/hazardous waste impacts.

CONCLUSION

Because Alternative A would impose no additional control or compliance requirements, with the exception of air quality, it would not be expected to generate significance adverse impacts. Air quality was concluded to be significant for this alternative because it would not necessarily eliminated or limit future exceedances of existing Rule 1110.2 emission control requirements. Further, Alternative A would not accomplish the two primary objectives of the proposed project, which are to reduce future violations of existing compliance requirements through enhanced enforcement and further reduce NOx, CO and VOC emissions from affected engines.

Alternative B would extend and increase the low-use exception to non-biogas engines and extend the 15 minute averaging time during compliance testing to one hour. Impacts from implementing Alternative B would generally be similar to PAR 1110.2 because the greatest impacts occur from the various compliance options for biogas engines. Compliance options are essentially the same for both Alternative B and PAR 1110.2. Alternative B may generate lower construction emissions overall compared to PAR 1110.2, but because major construction activities are anticipated to occur at biogas facilities the maximum daily construction emissions may not be different from those identified for PAR 1110.2. CO2 emission reductions would be similar to CO2 emission reductions identified for PAR 1110.2 because it is expected that replacing non-biogas ICEs with electric motors will be a less costly compliance option for the same categories of ICEs affected by both PAR 1110.2 and Alternative B. Aesthetic and hazards/hazardous material impacts are expected to be similar to PAR 1110.2 and, therefore, significant. Similarly, energy and solid/hazardous waste impacts are expected to be similar to PAR 1110.2 and, therefore, less than significant.

Alternative C would not impose any addition emission control requirements beyond what is currently required by existing Rule 1110.2. Alternative C would require additional CEMs, monitoring, testing, etc., to enhance enforcement of existing emission control requirements. Installation of CEMs, additional monitoring, etc., is not expected to change the visual character of the facility or surroundings and, therefore, would not be expected to generate significant adverse aesthetic impacts. Additional compliance requirements would not generate significant adverse construction or operational air quality impacts. Air toxics would be generated from source testing vehicle trips, but health risk from a single trip every other year would be negligible. Although Alternative C is not expected to achieve further emission reductions, it would not generate significant adverse air quality impacts. Adverse energy impacts from monitoring equipment and travel associated with additional source test are expected to be less than significant. Because Alternative C does not impose further emission control requirements, no facility operators would implement emission compliance options that could generate significant hazards/hazardous material impacts, because hazards would not be generated from increased monitoring and source testing. Alternative C would not generate significant solid or hazardous waste from monitoring or source testing. Therefore, Alternative C is not expected to create significant adverse impacts in any environmental topic areas.

Alternative D is expected to generate significant adverse environmental impacts similar to those identified for PAR 1110.2. Alternative D may incrementally increase adverse environmental impacts because larger or additional control may be required to meet the lower CO compliance concentration limits. CO2 emission reductions would occur through the mandatory replacement of non-biogas engines with electric motors for categories for categories of engines where this compliance option is less costly than complying with the emission control requirements. While in practice Alternative D could generate greater adverse environmental impacts, the assumptions applied to PAR 1110.2 would also apply to Alternative D because these assumptions provide the most conservative analysis possible. Therefore, for this analysis the adverse environmental impacts from PAR 1110.2 and Alternative D are equivalent. Alternative D would be expected to create significant adverse aesthetics, air quality, and hazards/hazardous waste. Like PAR 1110.2, Alternative D would not be expected to create significant adverse energy or solid/hazardous waste impacts

A comparison of the impacts from PAR 1110.2 and all project alternatives is presented in Table 5-28.

Pursuant to CEQA Guidelines §15126.6(e)(2), if the environmentally superior alternative is the no project alternative, the CEQA document shall also identify an environmentally superior alternative among the other alternatives. In the case of the alternatives to PAR

1110.2, the no project alternative is not considered to be the environmentally superior alternative. Alternative A – No Project Alternative, does not impose any additional requirements beyond those in existing Rule 1110.2 and as a result, does not generate any aesthetics, energy, hazards/hazardous materials, or solid/hazardous waste impacts. However, because Alternative A does not impose any compliance requirements to enhance enforcement, it would not necessarily prevent or limit future exceedances of the emission control requirements in existing Rule 1110.2. This is considered to be a significant adverse air quality impact. The only alternative that does not generate any significant adverse environmental impacts is Alternative C – Enhanced Enforcement, but it would not achieve the project objective of partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization. While the proposed project is the staff's proposed project, the Governing Board may choose to adopt any of the alternatives in whole or in part in place of the proposed project, based on other considerations in addition to environmental concerns such as compliance costs, effects on future employment (jobs lost, for example), etc.

The *CEQA Guidelines §15126.6(e)(2)* requires the environmentally superior alternative to be identified. In addition, SCAQMD Environmental Justice Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. Excluding Alternative A, the No Project Alternative, Alternative C would be the environmentally superior and least toxic alternative, because it would not require additional controls which may have adverse toxic impacts and require additional vehicle trips, but it would not achieve the project objective of partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization.

The proposed project is not the most environmentally superior project or lease toxic alternative (Alternative C is both). However, the proposed project would completely fulfill the project objective of further reducing NOx, CO and VOC emissions from ICEs and partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization, which Alternatives A and C do not, and is qualitatively environmentally better than Alternative D. PAR 1110.2 is preferred to Alternative B, because it would achieve greater reductions with similar adverse environmental impacts. While the proposed project is the staff preferred alternative, the Governing Board may choose to adopt any of the alternatives in whole or in part in place of the proposed project, based on other considerations in addition to environmental concerns such as compliance costs, effects on future employment (jobs lost, for example), etc.

Table 5-28
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Aesthetics	Significant	Not significant no Impact	Significant less than PAR 1110.2	Not significant	Significant Equivalent to PAR 1110.2
Air Quality					
Criteria	Significant	Significant, greater than PAR 1110.2	Significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Toxic	Significant	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2
Greenhouse Gas	Not significant beneficial effect	Not significant no beneficial effect	Not significant equivalent to PAR 1110.2	Not significant no beneficial effect	Not significant less than PAR 1110.2
Energy					
Electricity	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Natural Gas	Not significant beneficial effect	Not significant less than PAR 1110.2	Not significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Diesel	Not significant	Not significant no Impact	Not significant, less than PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Hazards/Hazardous Material	Significant	Not significant no Impact	Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Solid/Hazardous Waste	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, same as PAR 1110.2	Not significant Equivalent to PAR 1110.2