



Air Quality Guidance for Siting Biorefineries in California

**Stationary Source Division
November 2011**

**State of California
California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Source Division**

Air Quality Guidance for Siting Biorefineries in California

November 2011

This report has been reviewed by the staff of the California Air Resources Board. Publication does not signify that the contents necessarily reflect the view and policies of the Air Resources Board, nor does mention of trade names constitute endorsement or recommendation for use.

This Page Left Intentionally Blank

ACKNOWLEDGMENTS

Staff would like to acknowledge the significant contributions from the following working group members:

Will Barrett, American Lung Association
Jay Chen, South Coast Air Quality Management District
Jorge DeGuzman, Sacramento Metropolitan Air Quality Management District
Rudy Eden, South Coast Air Quality Management District
Sheraz Gill, San Joaquin Valley Air Pollution Control District
Bonnie Holmes-Gen, American Lung Association
Nick Lapis, Californians Against Waste
Thomas Liebel, South Coast Air Quality Management District
Loula Merkel, Coskata, Inc.
Rodney Millican, South Coast Air Quality Management District
Tim O'Connor, Environmental Defense Fund
Shankar Prasad, Coalition for Clean Air
John Shears, The Center for Energy Efficiency and Renewable Technologies
Scott Smithline, Californians Against Waste
Necy Sumait, Blue Fire Ethanol
Jordan Thaeler, Amyris
Charles Tupac, South Coast Air Quality Management District
Art Valla, Bay Area Air Quality Management District
Dave Warner, San Joaquin Valley Air Pollution Control District
Chuck White, Waste Management, Inc.
Hubert Wilson, South Coast Air Quality Management District

This Page Left Intentionally Blank

TABLE OF CONTENTS

	Page
Acronyms and Abbreviations.....	ix
Terminology	xi
EXECUTIVE SUMMARY.....	1
I. CALIFORNIA AIR REGULATORY STRUCTURE AND REGULATION OF STATIONARY SOURCE EMISSIONS.....	1
A. Regulatory Structure.....	1
B. Stationary Source Permitting	2
C. California Environmental Quality Act.....	6
D. National Environmental Policy Act	8
II. BIOFUEL PRODUCTION CONVERSION TECHNOLOGIES	11
A. Ethanol.....	11
B. Biodiesel	13
C. Renewable Diesel	13
D. Biogas.....	14
E. Hydrogen	15
F. Biogasoline	15
G. Emerging Biomass Conversion Technology – Algae-to-Biofuels	15
III. STATIONARY SOURCES OF EMISSIONS FOR EACH BIOFUEL CONVERSION TECHNOLOGY.....	17
A. Process Equipment Used at Biorefineries.....	17
B. Associated Air Pollutants	18
IV. EMISSIONS PERFORMANCE OF STATIONARY EQUIPMENT USED AT BIOREFINERIES	21
A. Background on BACT and Its Use in California	21
B. Grain Receiving, Conveying, and Grinding Operations.....	23
D. Fermentation Process—Yeast, Liquefaction, Beerwell, and Process Condensate Tanks.....	23
E. Distillation and Wet Cake Processes	24
G. Pumps and Compressor Seals	28
H. Valves, Flanges, and Other Connectors	29
I. Wet Cooling Tower	29
J. Natural Gas-Fired Dryer.....	30
K. Storage Tanks (Fixed Roof).....	31
L. Storage Tanks (Floating Roof).....	31
M. Flare (Ethanol Production).....	32
N. Liquid Fuel Loading Operations	33
O. Liquid Fuel Transfer and Dispensing Operations.....	33
P. Biomass-Fired Boilers.....	34
Q. Landfill Gas-Fired Flare	37

R. Manure Digester and Co-Digester Gas-Fired Flare	39
S. Compressed Gas Dispensing Operations.....	40
T. Combustion of Biogas.....	40
U. Other Operations and Equipment	51
V. GHG Emission Reduction Measures	55
W. Toxic Air Contaminant Emissions	58
 V. MOST STRINGENT EMISSION LIMITS FOR PROCESS EQUIPMENT AT BIOREFINERIES	 59
 VI. MOBILE SOURCE EMISSIONS ASSOCIATED WITH BIOREFINERIES.....	 67
A. Motor Vehicle and Mobile Equipment Used In Biorefinery Operations	67
B. ARB Mobile Source Regulations.....	68
C. Mitigation of Mobile Source Emissions Associated with Biorefineries.....	81
 VII. OTHER CONSIDERATIONS AND FUTURE UPDATES TO THIS REPORT.....	 85
A. Considerations for Highly Impacted Communities	85
B. Other Strategies to Minimize Air Emissions from Biorefineries	86
C. Updates to Report.....	87
 REFERENCES.....	 89

LIST OF TABLES

Table ES-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Evaporative Loss Sources
Table ES-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Combustion Sources
Table ES-3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Miscellaneous Sources
Table III-1. Process Equipment Requiring an Air Permit by Biofuel
Table III-2. Air Pollutants Associated with Processes Used at Biorefineries
Table IV-1. Waste Gas Emissions Standards for DG Certified by ARB
Table V-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Evaporative Loss Sources
Table V-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Combustion Sources

LIST OF TABLES (cont.)

- Table V-3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries - Miscellaneous Sources
- Table VI-1. Summary of Heavy-Duty Diesel Cycle and Medium-Duty Diesel Engine Emission Standards (g/bhp-hr)
- Table VI-2. Summary of Phase-In Schedule
- Table VI-3. Compliance Schedule for Vehicles with GVWR 26,000 Pounds or Less
- Table VI-4. Compliance Schedule for Vehicles with GVWR Greater than 26,000 Pounds
- Table VI-5. Phase-In Option for Vehicles with GVWR Greater than 26,000 Pounds
- Table VI-6. Implementation Schedule for Public Agency and Utility Fleet Vehicles
- Table VI-7. ARB Tier 1-4 Off-Road Diesel Engine Emission Standards in g/kWh (g/bhp-hr)
- Table VI-8. Large and Medium Fleet Targets for Use in Calculating Fleet Average Target Rates (g/bhp-hr)
- Table VI-9. Small Fleet Targets for Use in Calculating Fleet Average Target Rates (g/bhp-hr)
- Table VI-10. Fleet Average Emission Level Standards in g/kWh (g/bhp-hr) of HC+NO_x
- Table VI-11. PERP Fleet PM Emission Standard Requirements
- Table VI-12. Other Strategies to Mitigate Air Emissions from Mobile Sources Associated with Biorefineries

APPENDICES

- Appendix A: Low Carbon Fuel Standard Resolution
- Appendix B: List of Working Group Members
- Appendix C: Biomass Feedstocks Available for Biofuel Production
- Appendix D: Supporting Data for Most Stringent Emission Limits Identified for Process Equipment at Biorefineries

APPENDICES (cont.)

Appendix E: Biorefineries in California

Appendix F: Description of a Generalized Procedure for Determining BACT

Acronyms and Abbreviations

AB 2588	Air Toxics “Hot Spots” Program
AB 32	Assembly Bill 32, California Global Warming Solutions Act of 2006
AIP	achieved in practice (as it relates to BACT)
ARB	California Air Resources Board
ASTM	ASTM International
ATC	Authority to Construct
ATCM	airborne toxic control measure
avg	average
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BARCT	best available retrofit control technology
bhp	brake horsepower
CAA	Clean Air Act
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFB	circulating fluidized-bed
CH ₄	methane
CHP	combined heat and power
CNG	compressed natural gas
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
DDGS	distillers dried grains and solubles
DEIR	draft environmental impact report
DG	distributed generation
district	air pollution control or air quality management district
dscf	dry standard cubic foot
EF	emission factor
ERC	emission reduction credit
ESP	electrostatic precipitator
FGR	flue gas recirculation
FT	Fischer-Tropsch
GHG	greenhouse gas
gr	grain
GVWR	gross vehicle weight rating
H ₂ S	hydrogen sulfide
Handbook	ARB’s Air Quality and Land Use Handbook
HC	hydrocarbon
hp	horsepower
hr	hour
HRA	health risk assessment
IC engine	internal combustion engine
kW	kilowatt
lb	pound
lb/day	pounds per day
lb/hr	pounds per hour

Acronyms and Abbreviations (cont.)

lb/MMBtu	pounds per million British Thermal Units
lb/MWh	pounds per megawatt hour
LAER	lowest achievable emission rate
LNB	low NO _x burner
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSI	large spark-ignition
MDEP	Massachusetts Department of Environmental Protection
MMBtu/hr	million British Thermal Units per hour
MW	megawatt
N ₂	nitrogen
NACAA	National Association of Clean Air Agencies
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH ₃	ammonia
NH ₄	ammonium
NO _x	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O ₂	oxygen
Plan	AB 32 Scoping Plan
PM	particulate matter
PM ₁₀	particulate matter 10 micrometers in diameter and smaller
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million, by volume, dry
PSD	prevention of significant deterioration
RACT	reasonably available control technique
Report	Air Quality Guidance Document for Siting Biorefineries
SCAQMD	South Coast Air Quality Management District
scf	standard cubic foot
scfm	standard cubic foot per minute
SCR	selective catalytic reduction
SIP	State Implementation Plan
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMAQMD	Sacramento Metropolitan Air Quality Management District
SNCR	selective non-catalytic reduction
SOV	single occupancy vehicle
SO _x	oxides of sulfur
SWCV	solid waste collection vehicle
TAC	toxic air contaminant
VMT	vehicle miles travelled
VOC	volatile organic compound
working group	Air Quality Guidance Document for Siting Biorefineries working group

Terminology

Anaerobic Digestion: A bacterial decomposition process that operates in the absence of oxygen.

Bagasse: The dry, fibrous residue remaining after the extraction of juice from the crushed stalks of sugarcane.

Baghouse: An air pollution control device that traps particulate matter by forcing gas streams through fabric filter bags.

Best available control technology (BACT): BACT is determined for each emissions unit and is the most stringent emission level that:

- Has been achieved in practice for a given class or category of source, or
- Is contained in any implementation plan approved by the United States Environmental Protection Agency, or
- Is any more stringent control technique determined to be both technologically feasible and cost effective.

Best available retrofit control technology (BARCT): Defined in California Health and Safety Code, section 40406 as “an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source.”

Biodiesel: A fuel comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, designated B100, and meeting the requirements of the ASTM standard (ASTM) D6751.

Biogas: Gas produced by the anaerobic digestion of animal manure, food and yard waste, dedicated energy crops, organic material in landfills, and/or biosolids. The term biogas is also used in this Report to refer to gas produced by anaerobic digestion that has been treated to the level necessary to remove impurities for proper operation of downstream equipment and associated pollution control equipment. For simplicity, ARB staff is using the term biogas in this Report regardless of whether the level of treatment would produce a product gas that would fit the definition of biomethane.

Biofuel: Liquid, solid, or gaseous fuel produced from biomass feedstocks.

Biomass: Material of recent biological origin that can be converted to energy and other marketable products.

Biomethane: Biogas which has been upgraded to remove the bulk of the carbon dioxide, water, hydrogen sulfide, and other impurities from raw biogas to the level that the upgraded biogas can be used as an energy source in applications that require pipeline quality or vehicle-fuel quality gas.

Terminology (cont.)

Biorefinery: A facility that integrates biomass conversion processes and equipment to produce fuels, heat, electricity, and chemicals.

Biosolids: Organic material resulting from the treatment of sewage sludge or wastewater.

Cellulose: A long chain of sugar molecules that provides strength to the primary cell wall of green plants. Bacteria can convert cellulose to ethanol.

Compost: An organic material derived from the aerobic decomposition of plant and animal matter.

Compressed natural gas (CNG): Natural gas that has been compressed to a pressure greater than ambient pressure.

Ethanol: A two carbon liquid produced from biomass, such as corn, sugarcane, sugar beets, or cellulosic material.

Fermentation: The anaerobic enzymatic conversion of carbohydrates to alcohol, carbon dioxide, and water.

Fischer-Tropsch process: A catalyzed chemical reaction in which synthesis gas is converted into liquid hydrocarbons.

Gasification: The thermal decomposition of organic matter at high temperatures in a controlled oxygen atmosphere to produce a synthesis gas primarily comprised of carbon monoxide (CO), hydrogen, CO₂, and solid residues.

Glycerin: A liquid by-product of biodiesel production used in the manufacture of cosmetics, liquid soaps, inks, and lubricants.

Heating value: The amount of energy available from burning a given amount of biomass.

Hydrolysis: A chemical process in which a molecule is cleaved into two parts by the addition of a molecule of water.

Liquefied natural gas (LNG): A natural gas that has been pressurized and cooled so as to liquefy it for use as a vehicle fuel.

Lowest achievable emission rate (LAER): The most stringent emission limitation contained in the implementation plan of any state or achieved in practice for a class or category of source. It is a term from the federal New Source Review program and is required on major new or modified stationary sources in nonattainment areas.

Terminology (cont.)

Pyrolysis: A process where biomass feedstocks are broken down using heat in the absence of oxygen, producing a biooil that can be further refined to a hydrocarbon product. The decomposition occurs at lower temperatures than gasification processes, and produces liquid oil instead of a synthesis gas. Oil produced varies in oxygen content or viscosity according to the feedstock used.

Regenerative thermal oxidizer (RTO): An emission control strategy that uses high temperature thermal oxidation to convert VOCs to CO₂ and water.

Renewable diesel: A mixture of hydrocarbons derived from renewable non-petroleum sources, and meeting the requirements of ASTM D975. Renewable diesel is traditionally made from hydrotreatment of triglycerides.

Selective catalytic reduction (SCR): A post-combustion control technology that selectively reduces NO_x emissions by combining ammonia and oxygen with NO_x in the exhaust gas in the presence of a catalyst to form molecular nitrogen (N₂) and water.

Sewage sludge: The solids separated during the treatment of municipal wastewater.

Sodium methoxide: A base catalyst used in the production of biodiesel.

Synthesis gas (syngas): A combustible gas mixture containing varying amounts of CO, CO₂, and hydrogen that is produced by the gasification of organic matter.

This Page Left Intentionally Blank

EXECUTIVE SUMMARY

A. Introduction

On April 23, 2009, the Air Resources Board (ARB or Board) approved the adoption of the regulation to implement a Low Carbon Fuel Standard (LCFS or regulation) in California. The LCFS regulation applies to any transportation fuel, which is sold, supplied, or offered for sale in California, and to any regulated party, which is responsible for introducing transportation fuel into California's distribution system. The LCFS is designed to reduce California's dependence on petroleum, create a market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels in California. The LCFS will reduce greenhouse gas (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by an average of 10 percent by the year 2020. The regulation establishes performance standards that fuel producers and importers must meet each year beginning in 2011.

Implementation of the LCFS is expected to result in the installation of new biofuel production facilities (herein referred to as biorefineries) and the expansion of existing facilities in California. In the LCFS Initial Statement of Reasons, ARB staff recommended that the emissions associated with these facilities be fully mitigated consistent with local air pollution control and air quality management districts (districts) and California Environmental Quality Act (CEQA) requirements. To assist with this process, the Board directed staff to develop a best practices guidance document that could assist regulatory agencies, project proponents, environmental and public health groups, and other stakeholders, with assessing and mitigating air emissions associated with biorefinery activities in California.¹ This Report is in response to the Board's directive.

This guidance Report is intended to provide districts, regulated parties, and other stakeholders with information that can be used to ensure that new or expanding biorefineries are constructed and operated in a way that eliminates or minimizes adverse air quality impacts. This guidance is intended to promote general consistency in local permitting decisions.

This Report addresses both stationary source and mobile source emissions associated with biorefinery operation. Its primary purpose is to identify the most stringent permitted limits for air emissions from individual pieces of process equipment currently used or expected to be used at biorefineries, including power generating equipment,² and identify available options for mitigating air emissions from mobile sources at refineries, such as trucks and forklifts, beyond those limits achieved by ARB's mobile source regulations.

¹ See Resolution 09-31 for the Low Carbon Fuel Standard in Appendix A.

² The guidance applies to biomass-fired electric power generating boilers used at biorefineries, but is not intended to apply to stand-alone biomass-fired electric power generating plants.

B. Report Structure

The Executive Summary provides an introduction, background, and recommendations. There are seven chapters. A general description of each chapter is presented below.

- Chapter I, California Air Regulatory Structure and Regulation of Stationary Source Emissions, provides a broad overview of the air regulatory structure in California, the major provisions for permitting stationary equipment at new or expanding biorefineries, and the CEQA requirements that apply to proposed projects in the State.
- Chapter II, Biofuel Production Conversion Technologies, describes commercially available biofuel pathways and conversion technologies that could be found at biorefineries.
- Chapter III, Stationary Sources of Emissions for Each Biofuel Conversion Technology, identifies the stationary process equipment associated with each biofuel pathway identified in Chapter II, and the air pollutants associated with each process.
- Chapter IV, Emissions Performance of Stationary Source Equipment Used at Biorefineries, discusses the emissions data evaluated by ARB staff and staff's rationale in recommending the most stringent permitted emission limits for stationary equipment at biorefineries.
- Chapter V, Most Stringent Emission Limits for Process Equipment at Biorefineries, tabulates the most stringent permitted emission limits discussed in detail in Chapter IV.
- Chapter VI, Mobile Source Emissions Associated with Biorefineries, identifies vehicle and mobile equipment associated with new or expanding biorefineries, ARB mobile source regulations that were established to control the emissions from these types of sources, and outlines options to mitigate emissions from mobile sources at biorefineries.
- Chapter VII, Other Considerations and Future Updates, discusses other factors that should be considered when evaluating the impacts of a new or expanded biorefinery, such as the location of low income communities that are highly impacted by air pollution. This chapter also discusses the update process for this Report.

C. Using this Report

Air districts, local land use planners, environmental and public health groups, project proponents, and other stakeholders may find this Report useful for site selection, air quality permitting considerations, and identification of potential CEQA mitigation measures. This Report can assist stakeholders in evaluating the relative air quality impacts of the various conversion technology options that are available for the biofuels addressed by this Report. Proponents of biorefinery projects may use this Report to inform environmental and public health groups and other interested stakeholders about the emissions levels of proposed stationary equipment at biorefineries and the range of

options that could be used to mitigate mobile source emissions that are associated with the construction and operation of biorefineries. These options include obtaining mobile source emission reductions beyond what is required by in-use mobile source emission reduction regulations. Other options include minimizing the emissions from new or increased traffic from biorefineries by considering the use of routes that circumvent neighborhoods and sensitive receptors.

The information in this Report should be included in outreach activities that project proponents conduct to solicit stakeholder input on the site selection process and mitigation of both stationary and mobile source emissions. These outreach activities include holding public meetings during the project development phase, wide distribution of draft air permits and CEQA-related documents, and solicitation of input from fleet owners interested in potentially reducing equipment emissions beyond what is required by existing regulations.

In determining the appropriate air quality requirements for a project, the recommended emission levels and mitigation measures contained in this Report should be considered in combination with other air quality information, such as air quality attainment status, progress in achieving commitments contained in State Implementation Plans (SIP), site-specific modeling, availability of potential emissions mitigation measures, proximity to sensitive land uses, local health risk management policies, and availability of potential mobile source mitigation measures.

This Report is not intended to establish new best available control technology (BACT), identify best available retrofit control technology (BARCT) emissions levels, or verify emission levels claimed to be achievable by vendors of conversion technologies. BACT is determined on a case-by-case basis to account for advancements in technology and processes. This Report is not intended to substitute for the case-by-case permitting decisions conducted by local air quality, environmental, or planning agencies. In addition, this Report is not intended to preempt, replace, or devalue the decision-making processes that are associated with the outcomes of transportation planning analyses, site specific air quality modeling, risk assessments, SIP modeling, or future rules and regulations adopted for the purpose of controlling emissions of criteria pollutants, toxic air contaminants (TAC), or GHGs.

D. ARB's Role in Siting of Biorefineries

The ARB is charged with coordinating efforts to attain and maintain federal and State ambient air quality standards and to comply with requirements of the federal Clean Air Act.³ State and local regulations permit the ARB to participate in the air district permitting process for stationary sources and in the environmental siting process for local land use projects. The ARB is typically an informal participant in these processes. Consistent with the ARB's overall responsibilities, ARB staff may attend project workshops and hearings and generally function as a sounding board and resource to air district and local planning agency staff.

³ The ARB also has the primary responsibility for control of air pollution from vehicular sources.

Specific to the siting of biorefineries, the Board has directed that ARB staff participate in the environmental review of projects in California directly related to the production, storage, and distribution of transportation fuel subject to the LCFS program.⁴ ARB staff is directed to:

“evaluate the air quality impacts of these projects; and, as appropriate, identify feasible measures to mitigate the local and regional impacts of the projects. This effort is to be coordinated with the local air districts; lead agencies for preparation of environmental impact reports to comply with the California Environmental Quality Act; companies proposing to build new production, storage, and distribution facilities; and environmental and community representatives.”

ARB staff will review proposed biorefinery projects and provide comments to air district and local planning agency staff, as necessary, to reflect the recommendations outlined in this guidance.

E. Development of the Report

ARB staff solicited volunteers from stakeholders interested in the development of this Report and formed a working group with representation from the districts, biorefinery and waste management industries, and environmental and public health groups (see Appendix B for a list of working group members and their affiliations). Beginning in August 2009, the working group met by teleconference 11 times to discuss the drafting of this Report. In addition, ARB staff held two public workshops (August 2009 and January 2010) that included an update on progress and discussion of this Report.

ARB staff conducted a nationwide call for information about existing or planned biorefineries through the National Association of Clean Air Agencies (NACAA), and through several of California’s air districts. ARB staff compiled the most current stringent emission limits for process equipment used at biorefineries, and options available to mitigate mobile source emissions associated with biorefineries through review of:

- Adopted and proposed district rules;
- Control techniques required as BACT or Lowest Achievable Emission Rate (LAER);
- Emission levels achieved in practice, as verified by test results;
- More stringent control techniques which are technologically and economically feasible, but are not yet achieved in practice;
- Business, Transportation, and Housing and the California Environmental Protection Agency’s Goods Movement Action Plan (2007);
- California Air Pollution Control Officers Association’s Health Risk Assessment for Proposed Land Use Projects (2009);

⁴ See Resolution 09-31 for the Low Carbon Fuel Standard in Appendix A.

- California Air Resources Board's Air Quality and Land Use Handbook: A Community Health Perspective (2005);
- State and local CEQA guidelines; and
- Draft and final Environmental Impact Reports (EIR) for various industrial facilities.

ARB staff distributed a draft version of this Report to the LCFS listserve at ARB, and the Bioenergy listserve at the California Energy Commission (CEC) on October 11, 2010, for a public review period ending on December 1, 2010. ARB staff also conducted a publicly-noticed meeting on October 14, 2010, on the draft Report. After considering the comments, ARB staff issued the final version of this Report in November 2011.

F. Evaluation of Biorefinery Processes and Air Emissions

The information in this Report was compiled from ARB staff's evaluation of the types of biofuels that could potentially be produced at a California biorefinery, the commercially available conversion technologies used to produce these fuels, the process equipment and air pollutants associated with these technologies that would be subject to district permit requirements, and the most current stringent permitted emission levels for these processes. The biofuels evaluated include: ethanol from grains, sugarcane, and cellulose, biodiesel, renewable diesel, biogas, hydrogen, and biogasoline. The conversion technologies evaluated include: fermentation, hydrolysis, gasification, transesterification, anaerobic digestion, reformation, and acid fermentation. Staff also evaluated motor vehicle and mobile equipment that would typically be associated with biorefineries. These could include trucks used to deliver raw material to a facility, excavators used to maintain the facility infrastructure, and chippers used to process raw material.

The air pollutants evaluated include: oxides of nitrogen (NO_x), particulate matter (PM), volatile organic compounds (VOC), oxides of sulfur (SO_x), carbon monoxide (CO), and toxic air contaminants (TACs). Corresponding ammonia (NH₃) slip emission limits for stationary sources equipped with control technologies that use ammonia for the reduction of NO_x were identified in this Report for informational purposes. Regulatory agencies should evaluate and limit ammonia slip consistent with acceptable health risk exposure levels and/or applicable New Source Review Rules on a project-specific basis (see Appendix D).

Strategies to specifically mitigate GHG emissions from biorefineries were not evaluated in this Report. However, ARB is currently developing a number of broad and specific strategies to reduce GHGs from both stationary and mobile sources as part of its effort to satisfy the requirements in the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32). Many of the mitigation strategies provided in this Report will facilitate GHG reductions by promoting overall efficiency in energy conversion technologies and encouraging the recovery of energy and other marketable products from biomass feedstocks. Implementation of the mitigation strategies for both stationary and mobile sources will allow users of electricity, heat, and liquid and

gaseous fuels to reduce GHGs, partially offset their reliance upon fossil fuels, and preserve efforts to achieve and maintain federal and state ambient air quality standards and reduce TAC emissions.

G. Recommendations for Stationary Source Emission Limits from Biorefineries

Tables ES-1, ES-2, and ES-3 summarize the most current stringent emission limits for stationary process equipment that might be used at biorefineries. The tables are classified by equipment type – evaporative loss sources, combustion sources, and miscellaneous sources. A detailed discussion of the data set that ARB staff used to identify these limits is contained in Chapter IV and Appendix D. Where available, ARB staff included the permit-specific averaging times associated with the emission limits in Appendix D.

The alternate limits listed under certain equipment categories in Tables ES-2 and ES-3 were identified by ARB staff as being the most current stringent emission limit for an individual air pollutant contained in a rule, regulation, guidance document, BACT analysis, or permit. In the case of biogas-fueled fuel cells, the alternate limits are the future emission standards that will be required by statewide regulation as of January 1, 2013. Data collected by ARB staff indicates the 2013 standards may be achievable now, and therefore, ARB staff recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project. For the other equipment categories, ARB staff did not have sufficient data at the drafting of this Report to conclusively determine that the individual alternate limit is achievable in concert with the most stringent emission limits identified for the other regulated pollutants in that class/category of source. In these cases, ARB staff also recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project.

The emission limits contained in the following tables apply to normal operations and should not be construed as being achievable during startup, shutdown, or malfunction conditions.

The recommendations in this Report are current as of publication. However, ARB staff will continue to evaluate new emissions data and periodically provide updates to this Report using the process described in Chapter VII.

Table ES-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Methanol / Sodium Methoxide receiving and storage			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Fermentation process: yeast, liquefaction, beerwell, and process condensate tanks			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Distillation and wet cake processes			Emission limit corresponding to use of a VOC control system (wet scrubber or equivalent) capable of 95% or better control efficiency		
Pumps and compressor seals			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Valves, flanges, and other types of connectors			No leak of methane greater than 100 ppm above background and inspection and maintenance program		

Table ES-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Storage tank (fixed roof)			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Storage tank (floating roof)			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel loading operations			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel transfer and dispensing operations			Emission limit corresponding to use of an ARB certified Phase I vapor recovery system		

Table ES-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Natural gas-fired boiler, ≥ 2 to < 5 MMBtu/hr	Non-atmospheric units: 9 ppmvd @ 3% O ₂ (0.011 lb/MMBtu) Atmospheric units: 12 ppmvd @ 3% O ₂ (0.015 lb/MMBtu)	Firetube type: 50 ppmvd @ 3% O ₂ Watertube type: 100 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥ 5 to < 20 MMBtu/hr	6 ppmvd @ 3% O ₂ (0.007 lb/MMBtu)	Firetube type: ≤ 50 ppmvd @ 3% O ₂ Watertube type: ≤ 100 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥ 20 MMBtu/hr	5 ppmvd @ 3% O ₂ (0.0062 lb/MMBtu)	Firetube type: ≤ 50 ppmvd @ 3% O ₂ Watertube type: ≤ 100 ppmvd @ 3% O ₂ <u>For units ≥ 250 MMBtu/hr⁵:</u> 10 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired dryer	0.018 lb/MMBtu (15 ppmv @ 3% O ₂)	0.07 lb/MMBtu	Emission limit corresponding to use of a VOC capture and control with thermal or catalytic incineration (98% control) or equivalent	Emission limit corresponding to use of a wet scrubber (95% control)	Emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series (98.5% control) or equivalent

⁵ This CO limit may be required for boilers rated at < 250 MMBtu/hr if an oxidation catalyst is found to be cost effective, is necessary to meet toxic best available control technology, or for VOC emission control.

Table ES-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Flare (ethanol production)	0.05 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu
Biomass-fired boiler	0.012 lb/MMBtu (9 ppmvd @ 3% O ₂)	0.046 lb/MMBtu (59 ppmvd @ 3% O ₂) Alternate Limit: 0.01 lb/MMBtu (22 ppmvd @ 3% O ₂)	0.005 lb/MMBtu (11 ppmvd @ 3% O ₂)	0.012 lb/MMBtu (7 ppmvd @ 3% O ₂)	0.024 lb/MMBtu (0.01 gr/scf @ 12% CO ₂)
Landfill gas-fired flare	0.025 lb/MMBtu	0.06 lb/MMBtu	Emission limit corresponding to 98% VOC destruction efficiency or 20 ppmv @ 3% O ₂	Emission limit corresponding to use of a wet scrubber with 98% control efficiency	Emission limit corresponding to use of steam injection and/or knockout vessel
Manure digester and co-digester gas-fired flare	0.03 lb/MMBtu (25 ppmvd @ 3% O ₂)	Operate per manufacturer specifications to minimize CO	0.03 lb/MMBtu	Emission limit corresponding to use of a H ₂ S removal system (dry or wet scrubber or equivalent)	Emission limit corresponding to use of smokeless combustion and LPG or natural gas-fired pilot
Biogas-fired microturbine	0.5 lb/MWh As of 1/1/2013: 0.07 lb/MWh	6.0 lb/MWh As of 1/1/2013: 0.10 lb/MWh	1.0 lb/MWh As of 1/1/2013: 0.02 lb/MWh	N/A	N/A

Table ES-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Biogas-fired turbine, <3 MW	9 ppmvd @ 15% O ₂	60 ppmvd @ 15% O ₂	3.5 ppmvd @ 15% O ₂ ⁶	Landfill gas: Emission limit corresponding to use of landfill gas with sulfur content of no more than 150 ppmv as H ₂ S	Emission limit corresponding to use of a fuel gas pretreatment system for particulate removal
Biogas-fired turbine, ≥3 MW	5 ppmvd @ 15% O ₂			Digester gas: Emission limit corresponding to use of digester gas with sulfur content of no more than 40 ppmv as H ₂ S	
Biomass syngas-fueled ⁷ reciprocating internal combustion engine	5 ppmvd @ 15% O ₂	N/A	25 ppmvd @ 15% O ₂	N/A	N/A
Diesel-fueled emergency engine generator	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range ⁸	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range	Emission limit corresponding to use of CARB, or very low sulfur, diesel fuel (15 ppm sulfur by weight)	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range

⁶ Due to limited data set available for this Report on achievable VOC emission levels for landfill and digester gas-fired turbines, ARB staff recommends that regulatory agencies consult with the manufacturers on guaranteed emission levels, as well as, evaluate additional source tests to determine the appropriate VOC limit for a turbine.

⁷ BACT guideline that is the basis of these emission limits defines syngas, or synthetic gas, to be "derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (<5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide."

⁸ Refer to ARB regulations and/or Appendix D Table D-29 of this Report for the applicable emission standard.

Table ES-3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Miscellaneous Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Grain receiving, conveying, and grinding operations					Emission limit corresponding to use of a baghouse with 99% control, or equivalent
Wet cooling tower					Emission limit corresponding to use of a drift eliminator with 0.0005% drift loss
Compressed gas dispensing operations	No emissions – use of closed loop system with all vent and excess process gas directed to an on site treatment system, used in vehicles, or directed to another combustion or processing facility that can process the biogas and which has been issued a valid air permit				
Biogas-fueled fuel cell ⁹	0.5 lb/MWh Alternate Limit: 0.07 lb/MWh	6.0 lb/MWh Alternate Limit: 0.10 lb/MWh	1.0 lb/MWh Alternate Limit: 0.02 lb/MWh	N/A	N/A
Composting			Emission limit corresponding to use of a VOC control system (enclosure with biofilter or equivalent) capable of 80% or better control efficiency Ammonia: Emission limit corresponding to use of an NH3 control system capable of 80% or better control efficiency		Emission limit corresponding to use of a PM10 control system capable of 99% or better control efficiency

⁹ Emission limits are the 2008 standards for waste gas required by the ARB's Distribution Generation (DG) Certification Regulation. Alternate limits represent the 2013 standards for waste gas required by the DG Certification Regulation.

H. Recommendations for Mitigating Mobile Source Emissions from Biorefineries

On-road vehicles, off-road vehicles, and portable equipment used at biorefineries are a source of criteria pollutants, TACs, and GHGs. These mobile sources may be used for the following activities associated with biorefineries:

- construction and maintenance;
- delivery of raw product;
- processing of raw material and finished fuel product; and
- delivery of finished fuel product.

ARB staff recommends that on-road trucks serving biorefineries should have, at a minimum, 2007 model year engines, especially in areas where residents and sensitive receptors are present. Although ARB's On-Road Heavy-Duty Vehicle In-Use Regulation (Truck and Bus Regulation) does not yet require 2010 model year engines, ARB staff recommends project proponents use trucks with 2010 model year engines if available, as they provide additional NO_x reductions to reduce the air quality impacts from mobile sources and biorefineries in general. Other options to mitigate mobile source emissions associated with biorefineries include:

- Repower, retrofit, new purchases, replace, or use of alternative fuels to achieve earlier, more aggressive, or more comprehensive (e.g., including exempt equipment) emission reductions that go beyond regulatory requirements for in-use diesel-fueled mobile sources; and
- Application of other available mitigation options contained in Table VII-1 such as strategies targeting diesel PM and fugitive emissions reductions and reductions in vehicle miles travelled.

I. Considerations for Highly Impacted Communities

There are a few sources of information that have identified highly impacted communities in southern California and the San Francisco Bay Area based on air pollution and socio-economic indicators. The southern California communities mapped are the result of an environmental justice screening method developed as part of a project-specific study funded by ARB. The project results include a report entitled "Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making."¹⁰ The study investigators provided ARB with a relative ranking of census tracts in the South Coast Air Basin which integrates metrics of social vulnerability and indicators of air quality. The study investigators are currently developing maps for southern San Joaquin Valley (Fresno to Bakersfield), and they hope to eventually expand the tool to the whole State. In addition, the Bay Area Air

¹⁰ Pastor, M., Morello-Frosch, R., Sadd, J. (2010, May 3). *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making*. Final Report: Contract Number #04-308. Retrieved from <http://www.arb.ca.gov/research/apr/past/04-308.pdf>

Quality Management District's Community Air Risk Evaluation (CARE) program identifies six communities in that region based on pollution and other vulnerability indicators as guidance for pollution mitigation efforts. Information pertaining to both projects is available to the public.

This type of information should be considered in land-use and other decision-making processes, including in the siting or permitting of a new or expanding biorefinery project should it be located in, or in close proximity to these communities. It should be noted that the southern California screening method and Bay Area CARE program are specific, individual projects. Any analysis for highly impacted community purposes for any other projects should be evaluated on a case-by-case basis, absent an approved statewide method for identifying communities in California that are disproportionately impacted by air pollution.

Additional references that stakeholders may wish to use during the project-specific analyses for new or expanding biorefinery projects that pertain to community impacts include:

- California Air Resources Board's Air Quality and Land Use Handbook: A Community Health Perspective (2005);
- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007); and
- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009).

These references are available on ARB's Biorefinery Guidance website at <http://www.arb.ca.gov/fuels/LCFS/bioguidance/bioguidance.htm>.

J. Additional Strategies

This Report provides the most current stringent emission limits for stationary source process equipment used at biorefineries and available options to mitigate mobile source emissions associated with biorefineries. ARB staff recommends the following additional broad strategies to mitigate emissions from biorefineries:

- Use of onsite distributed generation (DG) and combined heat and power (CHP) systems in the form of fuel cells, microturbines, and other ultra-clean technologies.
- Where ultra-clean DG and CHP technologies are not technically feasible, promote the use of pipeline injection of biogas, rather than on-site combustion of biogas as a strategy to reduce emissions of NO_x in areas that do not achieve the federal or State Ambient Air Quality Standards for ozone;
- Promote the use of and explore economic and regulatory incentives for the maximum recovery of energy (particularly waste heat recovery) and other marketable by-products associated with biorefineries;

- Promote the use of and explore economic and regulatory incentives for cost effective and energy efficient emerging air pollution control strategies;
- Promote the use of and explore economic and regulatory incentives for fuel cells, microturbines, and other ultra-clean technologies that can be fueled by biogas; and
- Except for emergency purposes, minimize flaring of biogas or biofuel produced from biomass feedstocks.

K. Updates to Report

ARB staff's near-term update activities will focus on the distribution of new and updated BACT determinations, new source test results, new technologies, newly approved regulations (including test methods), and an updated list of existing biorefineries in California. This information will be posted to ARB's Biorefinery Guidance website at <http://www.arb.ca.gov/fuels/LCFS/bioguidance/bioguidance.htm>. ARB staff will send e-mail notifications to the LCFS listserve at ARB and the Bioenergy listserve at CEC when new information is posted to this website. ARB staff plans to provide these updates on an annual basis or as biorefinery project activity dictates.

In addition, to ensure the information provided in this Report stays current, ARB staff will perform periodic updates at intervals that correspond to the review periods set forth in the LCFS regulation. As part of these updates, staff will assess the geographic distribution of biorefineries in the state, and where appropriate, integrate additional mitigation measures for the purpose of protecting against disproportionate air quality impacts that arise from the concentration or co-location of multiple biorefineries.

This Page Left Intentionally Blank

I. CALIFORNIA AIR REGULATORY STRUCTURE AND REGULATION OF STATIONARY SOURCE EMISSIONS

In the air quality regulatory sector, biorefineries and other industrial facilities are known as “stationary sources,” while “mobile sources” include both on- and off-road sources such as trucks, heavy-duty construction equipment, and portable equipment. State law gives ARB direct authority to regulate pollution from mobile sources. Primary responsibility for controlling pollution from stationary sources lies with the districts.

This chapter presents a broad overview of California’s air regulatory structure, the major provisions for permitting stationary equipment at new or expanding biorefineries in California, CEQA requirements that apply to proposed projects in the State, and National Environmental Policy Act (NEPA) requirements that apply to projects subject to federal permits, such as those proposed on federal lands. An overview of vehicle and mobile equipment associated with new or expanding biorefineries and the ARB mobile source regulations established to control the emissions from these types of sources is provided in Chapter VI.

A. Regulatory Structure

The regulation of air pollution from various sources is conducted at three levels of government in California: federal, State, and local.

ARB has established health-based State ambient air quality standards to identify outdoor pollutant levels considered safe for the public. Once State standards are established, State law requires ARB to designate each area as attainment, nonattainment, nonattainment-transitional, or unclassified for each State standard. The area designations indicate the healthfulness of the air quality throughout the State. In addition, the federal Clean Air Act requires the U.S. EPA to set national ambient air quality standards (NAAQS) for wide-spread pollutants from numerous and diverse sources considered harmful to public health and the environment. A pollutant for which an ambient air quality standard is established is called a “criteria pollutant.”

The federal Clean Air Act requires states to directly regulate both stationary and mobile sources through a State Implementation Plan (SIP) to provide for implementation, maintenance, and enforcement of NAAQS. The SIP outlines all of the national, statewide, and regional strategies that will be used to meet air quality standards by a given date. At the federal level, U.S. EPA is responsible for implementation of the federal Clean Air Act. Some portions of the Act are implemented directly by U.S. EPA. Other portions are implemented by state and local agencies.

Responsibility for attaining and maintaining ambient air quality standards in California is divided among ARB and 35 independent local air districts. ARB and the districts follow the laws enacted by the California Legislature in the California Health and Safety Code and regulations promulgated by the U.S. EPA to do what is necessary to meet the requirements of the State and federal Clean Air Acts.

District responsibility includes developing region-specific rules, permitting, enforcement, collecting data associated with emissions inventory, and the preparation of local air quality plans. The districts may obtain authority from U.S. EPA to be the primary implementing and enforcing agency for certain federal requirements, such as New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and the Prevention of Significant Deterioration (PSD) program.

B. Stationary Source Permitting

This section summarizes the primary State and federal requirements for permitting stationary sources of air pollution in California. Each district has adopted a set of rules as part of the SIP to meet State and federal ambient air quality standards. District rules define the procedures and criteria that districts are to use in permitting stationary sources. Although specific rules vary among the districts in scope and level of stringency depending on the region's air quality status, the general procedure for permitting new and expanding sources is the same throughout the State. Most pollutant-emitting sources must obtain an authority to construct (ATC) before beginning construction and a permit to operate after the completed facility demonstrates compliance with district rules and the facility's permit conditions. Where applicable, district permit programs incorporate federal and State stationary source program requirements.

District requirements for stationary sources generally fit into two categories. The first category of rules applied to stationary sources is permitting rules for the construction and operation of new, modified (or expanding), or relocated stationary sources. These rules are referred to as the New Source Review (NSR) program. A second category of requirements includes rules which every source, or every source in a certain category of sources, must meet. These are often referred to as prohibitory or source specific rules. The rules apply whether a source is new or existing.

1. State New Source Review

The California NSR program is the foundation of stationary source emission control and allows industrial growth to continue in polluted areas without undermining progress toward meeting clean air standards. The NSR permit program is derived from the California Clean Air Act and is codified in Division 26 of the California Health and Safety Code. Specific to NSR, each district has a stationary source control program designed to achieve a "no net increase" in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. NSR programs provide mechanisms to (1) reduce emission increases up-front through the use of clean technology and (2) result in a net reduction in emissions. This is accomplished through two major requirements in each district NSR rule, which are BACT¹¹ and offsets.

¹¹ In California, BACT is synonymous with the federal term Lowest Achievable Emission Rate (LAER) for

a. Best Available Control Technology

Depending on the quantity of air pollutants that will be emitted from the source and the area designation for that pollutant, the new or modified source may be required to install BACT. BACT is triggered on a pollutant-by-pollutant basis and on an emission unit basis (generally an individual piece of equipment or an integrated process consisting of several pieces of equipment).

BACT requires use of the cleanest, state-of-the-art technology to achieve the greatest feasible emission reductions. In order to identify BACT for a specific piece of equipment or process, district staff conducts a comprehensive case-by-case evaluation of the cost and effectiveness of technologies or strategies. This includes obtaining testing results or similar proof that the emission levels have been achieved in practice. Achieved in practice can be determined if the technology is commercially available and has been in operation at a source for 12 or more months. District staff also conduct a broad search (internationally, in some instances) for technologies or strategies that have demonstrated (through testing on similar categories of stationary sources) a reduction in emissions to the lowest levels. The cost of the identified technologies is compared to the district BACT cost-effectiveness threshold. If the cost is lower than the threshold, then the technology or strategy can be designated as BACT for that category of stationary source. However, cost for technologies or strategies is not considered if the technology has already been deemed achieved in practice.

b. Emission Offsets

In addition to BACT requirements, owners of new or modified sources may be required to mitigate, or offset, the increased emissions that result after installation of BACT. Offsetting is the use of emission reductions from existing sources to offset emission increases from new or expanding sources. This may be done by purchasing emission reduction credits (ERCs) from another company or by concurrently cleaning up the existing facility which is undergoing expansion beyond what is required by law.

Offsets are generally required at a ratio greater than 1-to-1 resulting in an overall net air quality benefit within a district. If a source obtains emission offsets outside the local area (i.e., interbasin), or if one type of pollutant is offset against another type (i.e., interpollutant), the source must use air quality modeling to show that these offsets will result in a net air quality benefit. Some districts have pre-established ratios for interpollutant offsets in their rules.

c. Prohibitory/Source Specific Rules

Each district has rules aimed at limiting emissions from existing stationary sources. However, these rules apply to new sources as well. Prohibitory rules may be generic, such as limiting the maximum level of a particular pollutant (such as NO_x) at any facility;

nonattainment area permit requirements.

or they may be source specific, addressing specific equipment, such as a turbine, a boiler, or a reciprocating IC engine. Sources are also subject to a general nuisance rule which provides authority to the district to control the discharge of any air contaminants that will cause injury, detriment, nuisance, endangerment, discomfort, annoyance, or which have a natural tendency to cause damage to business or property. In most cases where BACT is required for a particular pollutant, the required control technology and corresponding emission level will be more stringent than what is required by the prohibitory or source specific rule. Except where a source is exempt from permit, the proponent of a new or expanding source will have to demonstrate compliance with both NSR and prohibitory rule requirements in any permit application submitted to the district.

2. Toxic Air Contaminant Requirements/Health Risk Assessment

Most districts evaluate TAC emissions at the same time that criteria pollutants are evaluated during the air permitting process. Sources emitting TACs must comply with district requirements regarding the risk assessment and risk management (mitigation) of these emissions. Some districts have established acceptable levels of health risk. Screening comprehensive health risk assessments (HRA) may be required as part of the permitting process, or as part of the State AB 2588 Hot Spots Program. In the case of significant health risks, districts may require mitigation measures to reduce risk. In addition, a new or expanding source, as well as existing sources, may be subject to either a federal NESHAP, a State-mandated airborne toxic control measure (ATCM) promulgated by ARB, or both.

As mentioned above, the impacts of TACs that are emitted from a stationary source project are addressed by an HRA. An HRA is an evaluation of the potential for adverse health effects that can result from public exposure to emissions of toxic substances. The information provided in an HRA can be used to decide if or how a project should proceed, including a requirement for additional mitigation measures. Some districts have regulations, or established policies, on using the results of HRAs to make risk management decisions.

An HRA addresses three categories of health impacts from various pathways of exposure: acute health effects, chronic non-cancer health effects, and cancer risks. Acute health effects generally result from short-term exposure to high concentrations of pollutants. Chronic non-cancer health effects and increased cancer risks may result from long-term exposure to relatively low concentrations of pollutants.

Air dispersion models are used to predict the ambient air concentrations of the toxic substances emitted by the source. The output from modeling is combined with pollutant-specific factors called unit risk factors (for cancer effects) or reference exposure levels (for acute and chronic non-cancer health effects). This information provides an estimate of the potential cancer risk (in chances per million) and potential non-cancer impacts expressed as a hazard index. Depending on the results, the district may approve the project as is, require additional pollution controls that represent the BACT for reducing TACs, or may reject the project altogether.

3. Ambient Air Quality Modeling

In California, most district permitting rules require evaluation of the air quality impacts of a project to be based on proposed emissions of the project. Air quality modeling is primarily used to demonstrate that the project does not create a new violation of a State or federal ambient air quality standard, or exacerbate an existing one. If there are projected new violations of standards, including Prevention of Significant Deterioration (PSD) requirements, the project may not be approved, unless acceptable mitigation measures are provided.

4. Federal Program

In addition to the district rules, there are also federal rules which govern the permitting of new or modified stationary sources—federal NSR and PSD. The purpose of federal NSR is to ensure that air quality improves, while allowing growth in areas with bad air quality (“nonattainment areas”), while PSD ensures that areas with good air quality will continue to maintain good air quality (“attainment areas”). Many district rules incorporate these federal regulations by reference. As in the State NSR program, federal nonattainment NSR regulations require LAER (similar to California BACT) and offsets.

New major stationary sources and major modifications at existing major stationary sources of attainment pollutants that meet emissions applicability thresholds outlined in the federal Clean Air Act and in existing PSD regulations must obtain a PSD permit outlining how they will control emissions. The permit requires facilities to apply federal BACT, which is determined on a case-by-case basis taking into account, among other factors, the cost and effectiveness of the control.

The Clean Air Act Amendments of 1990 required that all states develop operating permit programs. Under these programs, known as Title V operating permits programs, every major industrial source of air pollution (and some other sources) must obtain an operating permit. The permits, which are renewed every five years, contain all air emission control requirements that apply to the facility, including the requirements established as part of the preconstruction permitting process.

In addition to permitting rules, the U.S. EPA establishes rules that apply to specific industries and/or types of equipment. Rules that limit criteria pollutants are known as New Source Performance Standards (NSPS), and rule that limit hazardous (toxic) air pollutants are known as National Emission Standards for Hazardous Air Pollutants (NESHAP) and are also referred to and require Maximum Achievable Control Technologies (MACT).

The overall impact of the federal permitting regulations for criteria pollutants on stationary sources in California is minimal due to California’s more stringent

requirements, stemming from the California Clean Air Act and the more stringent California ambient air quality standards.

On May 13, 2010, U.S. EPA issued a final rule to address GHG emissions from stationary sources under the federal Clean Air Act permitting programs. The rule sets thresholds for GHG emissions that define when permits under the PSD and Title V operating permits programs would be required for new, modified, or existing facilities. The Clean Air Act permitting program emission thresholds for criteria pollutants are 100 and 250 tons per year. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs, because GHGs are emitted at much higher volumes. The rule “tailors” the permit programs to limit which facilities will be required to obtain PSD and Title V permits. Without this tailoring rule, these lower Clean Air Act thresholds would take effect automatically for GHGs on January 2, 2011. Many entities advocated for higher thresholds since the volume of permits at the standard thresholds would overwhelm U.S. EPA’s ability to process permit applications and issue permits.

The GHG tailoring rule requires PSD permitting of GHGs beginning January 2, 2011, if a source is already subject to PSD and GHGs are increased by 75,000 tons per year CO₂e. After July 1, 2011, PSD permits are required for new sources with GHG emissions at 100,000 tons per year CO₂e, or modifications at existing facilities that increase GHG emissions by at least 75,000 tons per year CO₂e regardless of whether or not they were already subject to PSD. New or modified facilities with GHG emissions that trigger PSD permitting requirements would need to apply for a revision to their operating permits to incorporate best available control technologies and energy efficiency measures to minimize GHG emissions. These controls will be determined on a case-by-case basis during the PSD process. U.S. EPA has developed BACT policy guidance.

Similar to the requirements for PSD permits, only sources currently subject to the operating permit program would be subject to Title V requirements for GHG emissions as of January 2, 2011. However, after July 1, 2011, Title V operating permit requirements will apply to sources based on their GHG emissions even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tons per year CO₂e will be subject to Title V permitting requirements.

ARB staff is currently working closely with U.S. EPA on the implications for California with respect to implementation of the GHG tailoring rule.

C. California Environmental Quality Act

Before the district can issue or deny a permit for a project which may have a significant effect on the environment, the project must comply with CEQA. State regulations for implementing CEQA are codified in title 14 of the California Code of Regulations beginning with Section 15000 (known as the State CEQA Guidelines). The purpose of CEQA is to ensure that the environmental impacts of a project and its alternatives are disclosed to governmental decision-makers and the public, and that any significant

adverse environmental impacts are mitigated to the maximum extent feasible. In general, the CEQA process addresses mitigation of project emissions that do not require a district permit or that are not already addressed by the district's regulatory program.

CEQA applies to governmental decisions that require the exercise of judgment or deliberation (i.e., "discretionary activities"), as opposed to decisions involving only objective measurements regarding the wisdom or manner of carrying out a project. In addition, CEQA does not apply to statutorily or categorically exempt projects, which are defined in CEQA and its implementing guidelines. By law, no regulatory agency can issue any permits until the project has been approved by the lead agency. The lead agency is generally the agency with the broadest discretionary authority in approving the project. This is typically the local land use agency, such as a county planning department. However, in some cases, the local air district could be the lead agency.

1. The CEQA Process

A project subject to CEQA review is analyzed to determine if there is the possibility of a significant effect on the environment. If a significant effect is possible, the lead agency prepares an initial study to evaluate the potential for an effect. If there are no potential significant effects, a negative declaration is issued by the lead agency. If a potential impact exists which the project proponent can and will commit to mitigate, a mitigated negative declaration can be issued. Otherwise, the lead agency will issue a notice of preparation of an EIR or equivalent. At this point, responsible agencies may comment on the required content of the EIR. These comments are then used by the lead agency to produce a draft environmental impact report (DEIR). The purpose of a DEIR is to assess any significant effect on the environment by the project and to evaluate potential mitigation measures. This report is available for review by responsible agencies and the public during the public review period. Comments on the DEIR by any of these parties may be submitted prior to the end of the public review period on such topics as completeness and accuracy of the draft EIR. The lead agency then reviews these comments and prepares a final EIR with responses to comments on the draft EIR. The final EIR is used by the lead agency in approving the project and by responsible agencies in issuing permits.

2. CEQA Requirements

With respect to air quality impacts, CEQA review generally focuses on identifying the additional emissions related to projects that affect land uses. CEQA Guidelines provide a set of criteria to determine whether a project will: (1) conflict with or obstruct implementation of the applicable air quality plan; (2) violate any air quality standard or contribute substantially to an existing or projected air quality violation; (3) result in a cumulatively considerable net increase of any criteria pollutant for which the region is nonattainment for State or federal standards; (4) expose sensitive receptors to substantial pollutant concentrations; or (5) create objectionable odors affecting a

substantial number of people. These criteria may be used by lead agencies to evaluate potentially significant effects.

Where applicable, the emission thresholds established by the district may be relied upon to make CEQA determinations of significance. However, unlike district rules, CEQA analyses must consider: impacts of facility construction; indirect emissions from increased mobile source activity; and the cumulative impacts of other projects within the area. For example, construction impacts might include fugitive dust emissions raised by mobile construction equipment. Indirect emissions may include emissions from trips to and from work by employees as well as increases in emissions from commercial vehicles using the facility. The lead agency can, at times, require air quality mitigation measures that go beyond the permitting requirements of the local air district.

Cumulative effects means the individual effects from the project are considered along with the effects of past projects, other current projects, and reasonably foreseeable future projects. Air quality impacts can be estimated using air quality modeling. The significance of new emissions can be compared to growth projections of emission forecasts in the SIP. If there is a significant impact, the lead agency will evaluate the need for mitigation measures or alternatives identified in the EIR, such as providing offsets, before approving the project.

D. National Environmental Policy Act

Biorefinery projects may be subject to the National Environmental Policy Act (NEPA) if the project requires a permit issued by a federal agency – for example a project involving federal lands or impacting waters of the United States. NEPA establishes a public, interdisciplinary framework for federal decision-making and ensures that agencies take environmental factors into account when considering federal actions. NEPA requires that agencies follow a particular process in making decisions and to disclose the information or data that was used to support those decisions. NEPA mandates that each agency develop procedures for implementing the basic NEPA requirements. The agencies' procedures are adopted as federal regulations after input from the public and approval of the Council on Environmental Quality. Agencies can also develop policy to complement their regulations.

NEPA requires agencies to follow a three-step review process:

1. Conduct a preliminary screening for NEPA's applicability (NEPA is not required for proposed actions that are considered "categorical exclusions," for example);
2. Prepare an Environmental Assessment to determine whether an Environmental Impact Statement (EIS) is required; and
3. Prepare an EIS if required (an EIS is required if a proposed action may "significantly affect the quality of the human environment").

The NEPA process can also serve to meet other environmental review requirements. For instance, actions that trigger the NEPA process may have an impact on endangered

species, historic properties, or low income communities. The NEPA analysis, which takes into account the potential impacts of the proposed action and investigates alternative actions, may also serve as a framework to meet other environmental review requirements, such as the Endangered Species Act, the National Historic Preservation Act, the Environmental Justice Executive Order, and other federal, state, tribal, and local laws and regulations.

The U.S. EPA's Office of Federal Activities reviews EISs and some Environmental Assessments issued by federal agencies. It provides its comments to the public by publishing summaries of them in the Federal Register, a daily publication that provides notice of federal agency actions. U.S. EPA's reviews are intended to assist federal agencies in improving their NEPA analyses and decisions.

Many federal agencies have established offices dedicated to NEPA policy and program oversight. These offices prepare NEPA guidance, policy, and procedures for the agency, and often make this information available to the public through sources such as Internet websites. Most NEPA agency procedures are available on-line at the NEPAnet website <http://ceq.eh.doe.gov/nepa/regs/agency/agencies.cfm>.

This Page Left Intentionally Blank

II. BIOFUEL PRODUCTION CONVERSION TECHNOLOGIES

This chapter contains a description of the more common biofuel production conversion technologies ARB staff determined are either currently available or industry has indicated will soon be available for commercial use in California. Appendix C contains a listing of all the biomass feedstocks that could theoretically be used to produce biofuels.

A. Ethanol

Ethanol is produced by the fermentation of sugar obtained from grains, sugarcane, and cellulose.

1. Ethanol from grains

The typical grain feedstocks for the production of ethanol include corn and wheat. Grains contain starch, a polymer of glucose, which must be broken apart before the sugar can be fermented. There are two methods for processing grain feedstock: dry mill and wet mill. Both are followed by fermentation to produce ethanol.

a. Dry mill processing/Fermentation

Grain feedstock is milled into a flour or fine meal to expose the starch. The material is then mixed with water to produce a mash. The mash is processed in a high temperature cooker with enzymes to convert the starch to sugar and reduce bacterial contamination. After the starch has been hydrolyzed to its component sugars, it is fermented using yeast under anaerobic conditions. After fermentation, the resulting ethanol is concentrated using conventional distillation methods. Distillation is followed by purification of the ethanol. The by-products of fermentation are known as distillers' grain. Distillers' grain may be partially dried and mixed with solids to produce wet distillers' grain with solids or further dried to produce dry distillers' grain with solids. Both may be used as animal feed.

b. Wet mill processing/Fermentation

Grain feedstock is steeped in water and a dilute sulfurous acid solution for one to two days. After the grain has finished steeping, the slurry is passed through a series of grinders, centrifuges, screens, and separators, which separate the corn into starch, protein, fiber, and germ. The starch and remaining water are processed into ethanol by a fermentation process similar to the dry mill production process described above. The resulting distillers' grain may be used as discussed above. Fermentation is followed by distillation and purification of the ethanol.

2. Sugarcane Ethanol

Potential sugar feedstocks for the production of ethanol include sugar cane, sweet sorghum, sugar beets, molasses, and surplus sugar from sugar refining plants.

Sugar syrup from pressed sugar crops is fermented by yeast under anaerobic conditions with minimal pre-processing. Fermentation is followed by distillation and purification of the ethanol as described above for corn ethanol production. The dry, fibrous residue remaining after the extraction of juice from the pressed sugar crops is known as bagasse. Bagasse may be used as animal feed, a potential feedstock for cellulosic ethanol, or burned for electricity.

3. Cellulosic Ethanol

Potential cellulosic feedstocks for the production of ethanol include dedicated crops, crop and forest residues, bagasse from sugar crops, municipal solid waste, and furniture manufacturing by-products. Cellulosic feedstock is made up of cellulose and hemicellulose. Both are polymers of various sugars that can be hydrolyzed and fermented to form ethanol. There are two methods for producing ethanol from cellulosic feedstock: hydrolysis followed by fermentation and gasification followed by Fischer-Tropsch (FT) synthesis or fermentation.

a. Hydrolysis/Fermentation

Cellulosic feedstock is cleaned and chipped to the proper size. A chemical pretreatment hydrolyzes the hemicellulose to its component sugars. Following pretreatment, cellulose is hydrolyzed to glucose. There are two methods of hydrolysis used to break down cellulose to glucose. The enzyme hydrolysis process uses enzymes, while the acid hydrolysis process uses acids as catalysts. The resulting glucose is fermented using microorganisms under anaerobic conditions. Fermentation is followed by distillation and purification of the ethanol.

b. Gasification/Alcohol Synthesis

Cellulosic feedstock is dried and chipped to the proper size. It is then fed to a gasifier where it is thermally decomposed in a controlled oxygen atmosphere at high temperatures. Gasification of the cellulosic feedstock produces synthesis gases (syngas) that include hydrogen, methane (CH_4), nitrogen, and light hydrocarbons, which can be used to produce ethanol. There are two methods for producing ethanol from syngas: modified FT synthesis and fermentation.

i. Modified Fischer-Tropsch Synthesis

Syngas is compressed and treated to reduce acid gas concentrations. Following further compression, it is heated to alcohol synthesis reaction conditions. The syngas is converted to mixed alcohols in a fixed bed reactor in the presence of a catalyst. The mixed alcohol stream is dehydrated and introduced to a separation column to separate methanol and ethanol from the other alcohols.

ii. Fermentation

Syngas is conditioned and compressed for fermentation. The syngas is fermented to ethanol using genetically engineered microorganisms under anaerobic conditions. Fermentation is followed by distillation and purification of the ethanol.

B. Biodiesel

Potential feedstocks for the production of biodiesel include plant oils, such as soybean and peanut; and animal fats, such as restaurant grease and tallow from rendering plants.

In a process known as transesterification, raw oils and fats are filtered and pretreated to remove water and contaminants. Following pretreatment, the oils and fats are mixed with an alcohol in the presence of a catalyst in a closed-reactor system at low temperature and pressure. The oils and fats are converted to fatty acid methyl esters and glycerin, which are separated and purified. Excess alcohol and impurities are removed from the crude biodiesel. The glycerin by-product can be purified and used in the pharmaceutical or cosmetic industries.

C. Renewable Diesel

Potential feedstocks for the production of renewable diesel include waste fats; plant oils; and biomass feedstocks, such as crop and food processing residues, green landscaping or food waste, paper, and wood waste. There are four methods for producing renewable diesel: hydrogenation, coproduction, flash pyrolysis followed by hydrotreatment, and gasification followed by FT synthesis. Fuel produced by these processes is referred to as renewable diesel to differentiate it from biodiesel produced by transesterification.

1. Hydrogenation

Plant oils and animal fats are refined to produce hydrogenation-derived renewable diesel. The oil or fat is upgraded into diesel, propane, and other light hydrocarbons through hydrotreatment with hydrogen.

2. Coproduction

Waste fat is preheated then mixed with a distilled crude oil stream and processed in a hydrotreater. The coproduction process also produces propane and petroleum products.

3. Flash Pyrolysis/Hydrotreatment

The biomass feedstock is dried and chipped to the proper size for rapid heat transfer. The pyrolysis reaction occurs in a fluidized bed reactor using an inert material such as

sand to transfer heat to the incoming biomass particles. The biomass is flash vaporized and becomes a mixture of gas, vapor, aerosols, and solid char. The gases are separated using a cyclone and then enter a quench tower where they are cooled and condensed into liquid “bio-oil”. The bio-oil is refined through hydrotreatment to produce renewable diesel. Pyrolysis also produces gaseous fuels, solid carbon, and/or char. Excess heat captured from the pyrolysis system can be used to produce hot water or steam for other processes.

4. Gasification/Fischer Tropsch Synthesis

The biomass feedstock is dried and chipped to the proper size. It is then thermochemically converted to syngas through gasification. Following clean-up, the syngas is sent to a low temperature FT reactor with a metal catalyst. The liquids produced by the FT reactor can be upgraded to diesel using a combination of hydrotreatment, hydrocracking, and hydroisomerization methods. The by-product gases produced from the FT reactor can be diverted and recycled back through the reactor to generate additional hydrocarbon products, or they can be used to generate power or steam.

D. Biogas

Potential feedstocks for the production of biogas include animal manure, food and yard waste, dedicated energy crops, food processing waste, organic material in landfills, and biosolids.

1. Anaerobic Digestion

Biomass feedstock is broken down by bacteria to fatty acids, alcohol, carbon dioxide (CO₂), hydrogen, ammonia and sulfides. Acid-forming bacteria further metabolize the products of hydrolysis into acetic acid, hydrogen and CO₂. Finally, methane forming (methanogenic) bacteria convert these products into a biogas containing CH₄, CO₂, sulfur compounds, PM, and water. Anaerobic digestion also produces residues that can be used as soil amendments or animal bedding.

a. Landfill Gas

Organic waste in municipal solid waste landfills decomposes to produce landfill gas. Landfill gas can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). Production of CNG from landfill gas requires removal of water, pretreatment to remove trace organics and CO₂, and compression. Production of LNG from landfill gas requires a cryogenic process to liquefy it.

b. Digester Gas

Digester gas contains CH₄, CO₂, sulfur compounds, PM, and water. Removing almost all of the CO₂, sulfur compounds, PM, and water from the biogas generated by a

digester produces biomethane. After pretreatment and compression, biomethane can be used as a transportation fuel.

E. Hydrogen

Potential biomass feedstocks for the production of hydrogen include crop and food processing residues, green waste, paper, wood waste; and biogas. There are two methods for producing hydrogen: gasification and reformation.

1. Gasification

Biomass feedstock is dried and chipped to the proper size. It is then thermochemically converted to syngas through gasification. The syngas is then processed to remove impurities.

2. Reformation

Methane-rich biogas reacts with steam under pressure in the presence of a catalyst to produce hydrogen, CO, and a small amount of CO₂. CO and steam are reacted using a catalyst to produce CO₂ and additional hydrogen. The syngas is then processed to remove impurities.

F. Biogasoline

Biogasoline, or renewable gasoline, is gasoline produced from biomass feedstock. Like traditional gasoline, it can be used in internal-combustion engines (IC engine).

Biomass feedstock is treated with lime to enhance its digestibility. The lime-treated biomass is fermented to produce a mixture of carboxylic acids. Calcium carbonate is added to neutralize the acids to form their corresponding carboxylate salts. These salts are then dewatered, concentrated, dried and thermally converted to ketones, which are hydrogenated to alcohols. The resulting carboxylic acids, ketones, primary alcohols, and secondary alcohols can be distilled to produce gasoline, diesel and jet fuel.

G. Emerging Biomass Conversion Technology – Algae-to-Biofuels

Algal biofuels is a large research area in California. Algae can be used to produce biodiesel, ethanol, and biobutanol. Algae use sunlight to convert simple sugars into oils or complex carbohydrates and store these substances in cells. The oils algae produce can be harvested and physicochemically converted into biodiesel, while the algae's carbohydrate stores can be biochemically converted into ethanol.

Some algae strains can produce oils that are suitable for biodiesel production, while other strains can produce oils that have qualities resembling light crude oil. Genetic modification is being considered as one method to produce algae strains that produce more oil, or are better adapted to particular production environments.

The U.S. Department of Energy investigated algae-to-biofuel production in the Aquatic Species Program from the late 1970s to 1996. There are a number of companies conducting research using pilot scale projects to produce fuels from algae. These projects include using open ponds to raise algae; bioreactor systems that feed CO₂ combustion emissions to algae; growing algae in fermentation tanks without sunlight; and using algae-infested water systems to produce biofuel. ARB staff will monitor algal biofuel progress and provide information on any commercially operating algae-to-biofuel production facilities through the update process described in this Report.

III. STATIONARY SOURCES OF EMISSIONS FOR EACH BIOFUEL CONVERSION TECHNOLOGY

This chapter is intended to provide an overview of the typical equipment at biorefineries that is expected to be subject to district permit requirements. This chapter summarizes the stationary sources of emissions and their associated pollutants for the biofuel production conversion technologies addressed by this Report. The equipment and emission points identified are based on facility designs from permits acquired by ARB staff and therefore should not be construed to reflect a one-size-fits-all profile.

A. Process Equipment Used at Biorefineries

Table III-1 identifies the process equipment that would be subject to district permit requirements for each biofuel addressed in this Report. The “X” indicates that ARB staff expects the process equipment to be used in the production of that particular biofuel.

Table III-1. Process Equipment Requiring an Air Permit by Biofuel

Process Equipment/ Emission Point	Biofuel						
	Grain Ethanol	Sugarcane Ethanol	Cellulosic Ethanol	Biodiesel	Renewable Diesel	Biogas	Hydrogen
Grain/feedstock receiving, conveying, and grinding operations	X	X	X		X		
Fermentation process-yeast, liquefaction, beerwell, and process condensate tanks	X	X	X				
Distillation and wet cake process	X	X	X				
Natural-gas fired boiler	X	X	X	X			
Pumps and compressor seals	X	X	X	X			
Valves, flanges, and other connectors	X	X	X	X	X	X	
Wet Cooling tower	X	X	X				
Storage tanks (fixed roof)				X	X		
Storage tanks (floating roof)	X	X	X				
Biomass-fired boiler	X	X	X				
Dryer	X						
Flare	X	X	X			X	
Compressed gas dispensing operation						X	
Biogas fuel cell						X	X
Compost piles						X	X
Biogas-fired microturbine						X	
Biogas-fired reciprocating IC engine						X	

Table III-1. Process Equipment Requiring an Air Permit by Biofuel (continued)

Process Equipment/ Emission Point	Biofuel						
	Grain Ethanol	Sugarcane Ethanol	Cellulosic Ethanol	Biodiesel	Renewable Diesel	Biogas	Hydrogen
Biogas-fired turbine						X	
Thermal conversion technology, non- incineration (e.g., pyrolysis, gasification)	X	X	X		X	X	
Syngas-fired reciprocating IC engine ¹²	-	-	-	-	-	-	-
Diesel-fueled emergency engine generator	X	X	X	X	X	X	X

B. Associated Air Pollutants

Table III-2 identifies the air pollutants typically associated with the biorefinery process equipment identified in Table III-1.

Table III-2. Air Pollutants Associated with Processes Used at Biorefineries

Process Equipment/ Emission Point	Pollutant				
	NOx	CO	VOC	SOx	PM10
Grain/feedstock receiving, conveying, and grinding operations					X
Fermentation process- yeast, liquefaction, beerwell, and process condensate tanks			X		
Distillation and wet cake process			X		
Natural-gas fired boiler	X	X	X	X	X
Pumps and compressor seals			X		
Valves, flanges, and other connectors			X		
Wet cooling tower					X
Storage tanks (fixed roof)			X		
Storage tanks (floating roof)			X		
Biomass-fired boiler	X	X	X	X	X
Dryer	X	X	X	X	X
Flare	X	X	X	X	X
Compressed gas dispensing operation	-	-	-	-	-
Biogas fuel cell	X	X	X	X	X
Compost piles			X		X
Biogas-fired microturbine	X	X	X	X	X
Biogas-fired reciprocating IC engine	X	X	X	X	X
Biogas-fired turbine	X	X	X	X	X
Thermal conversion technology, non-incineration (e.g., pyrolysis, gasification)	X	X	X	X	X

¹² ARB staff located one biomass-derived syngas-fired engine. The engine drives a generator to produce electricity and is not used to produce transportation fuels, so it is not included in the table.

**Table III-2. Air Pollutants Associated with Processes Used at Biorefineries
(continued)**

Process Equipment/ Emission Point	Pollutant				
	NOx	CO	VOC	SOx	PM10
Syngas-fired reciprocating IC engine	X	X	X	X	X
Diesel-fueled emergency engine generator	X	X	X	X	X

This Page Left Intentionally Blank

IV. EMISSIONS PERFORMANCE OF STATIONARY EQUIPMENT USED AT BIOREFINERIES

This chapter discusses ARB staff's supporting documentation and rationale for identifying the most current stringent permitted emission limits for criteria pollutants emitted from stationary equipment at biorefineries. The limits are summarized by process in Chapter V. Appendix D is a companion to this chapter and contains the data set of information ARB staff used to determine the limits. Appendix E contains a list of biorefineries in California from which some of the data contained in this report was received.

In identifying the most current stringent permitted emission levels for equipment used at biorefineries, ARB staff reviewed control technologies and corresponding emission levels contained in the following sources:

- adopted and proposed district rules;
- control techniques required as BACT;
- permitted emission levels achieved in practice, as verified by test results; and
- more stringent control techniques which are technologically and economically feasible, but are not yet achieved in practice.

The above sources were obtained from ARB and other regulatory agency BACT guidance documents; BACT determinations listed in the Bay Area Air Quality Management District (BAAQMD), California Air Pollution Control Officers Association (CAPCOA), South Coast Air Quality Management District (SCAQMD), and San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT clearinghouses; U.S. EPA RACT/BACT/LAER¹³ Clearinghouse; California air district rules; and air permits and corresponding source tests. The references that ARB staff used as the basis for each emission limit are referenced in this chapter by the table and number they have been assigned in Appendix D.

A. Background on BACT and Its Use in California

Federal regulations found in Parts 51 and 52 of Title 40 Code of Federal Regulations (40 CFR Parts 51 and 52) specify that one of two levels of emission control will apply to a new or modified stationary source of criteria pollutants subject to major source permitting requirements. The control requirements are pollutant-specific and depend on an area's attainment status for the ambient air quality standards; a district may have an attainment designation for some pollutants and a nonattainment designation for other pollutants. The more stringent federal requirement is termed "lowest achievable emission rate (LAER)"¹⁴ and is required when an area is nonattainment for a standard;

¹³ RACT means reasonably available control technology; LAER means lowest achievable emission rate.

¹⁴ Federal LAER is defined in section 171(3) of the federal Clean Air Act. It states that "The term 'lowest achievable emission rate' means for any source, that rate of emission which reflects – (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or

the less stringent federal requirement is termed “best available control technology (BACT)”¹⁵ and is required when an area is in attainment, or has an “unclassified” designation, for a standard. However, districts in California use the term “BACT” exclusively when referring to the emission control requirements of their New Source Review (NSR) permitting programs. Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as “California BACT.” One should take note not to confuse “California BACT” with the less restrictive federal BACT. Because each district has its own set of definitions and rules, the definition of BACT and, where used, LAER can vary by district. As a result, stakeholders should consult individual district rules to determine the appropriate requirements for a project.

Unless otherwise indicated, the use of the term “BACT” in this Report will refer to the emission control requirements in California as defined in a district’s NSR permitting program regulation, often referred to as “California BACT.” With some variation, the districts’ BACT definitions generally share the following elements:

- BACT is determined for a given “class or category of source;”
- BACT is generally specified as the most stringent emission level of these three alternative minimum requirements:
 - The most effective control achieved in practice,
 - The most stringent emission control contained in any approved State Implementation Plan (SIP),
 - Any more stringent emission control technique found by the district to be both technologically feasible and cost effective; and
- BACT emission limits must not be less stringent than a New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or any other applicable federal, State, or district requirement.

As part of the NSR process, the district must review an applicant’s proposed BACT for the project’s emission sources. The BACT determination must be consistent with the district’s BACT definition and is a demonstration that the emission source will be constructed, or modified, in such a manner that its operation will release the least amount of air pollutants possible. Appendix F contains a discussion of the generalized procedure for making a BACT determination.

category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.’

¹⁵ Federal BACT is defined in section 169(3) of the federal Clean Air Act. It states that the ‘term “best available control technology” means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques,...’

B. Grain Receiving, Conveying, and Grinding Operations

1. Control of PM10 Emissions

PM10 is emitted when dry materials, such as corn, are handled and processed. The control devices available for mitigating PM10 emissions are the same as those used in other industries that handle and process dry product, such as cement manufacturing, sand and gravel processing, and food manufacturing operations.

The most stringent PM10 limit for grain receiving, conveying, and grinding operations is an emission level corresponding to the use of a baghouse with 99 percent control efficiency. This control method is required in the permit for Reference 1 in Table D-1. The requirement is consistent with PM10 BACT requirements for similar bulk material handling operations at comparable facilities, as shown in SCAQMD BACT guidelines (see References 3, 4, 5, and 6 in Table D-1).

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of a control system (baghouse, or equivalent technology) capable of 99 percent or better control efficiency.

C. Methanol/Sodium Methoxide Receiving and Storage

1. Control of VOC Emissions

The most stringent VOC limit for tanks involved in the receiving and storage of methanol or sodium methoxide is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is required in the permit for Reference 1 in Table D-2. The control efficiency can be met with distillation column and two-stage vapor condenser. Additional permits for methanol/sodium methoxide receiving and storage operations for biorefineries located in California require use of a VOC control system with 95 percent control efficiency (References 2, 3, and 4 in Table D-2).

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 99.5 percent or better control efficiency.

D. Fermentation Process—Yeast, Liquefaction, Beerwell, and Process Condensate Tanks

1. Control of VOC Emissions

The most stringent VOC limit for tanks involved in the fermentation process is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is determined to be achieved-in-practice BACT for VOCs in SJVAPCD Guideline 4.12.4 (see Reference 3 in Table D-3). The control efficiency can

be met with a fermentation wet scrubber vented to a CO₂ recovery plant with a condenser and high-pressure scrubber or equivalent technology. The VOC control efficiency was demonstrated in source tests for References 1 and 2 in Table D-3.

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system (fermentation wet scrubber, high pressure scrubber, or equivalent technology) capable of 99.5 percent or better control efficiency.

E. Distillation and Wet Cake Processes

1. Control of VOC Emissions

The most stringent VOC limit for distillation and wet cake processes is an emission level corresponding to the use of a VOC control system with 95 percent control efficiency. This is required as achieved-in-practice BACT for VOCs in SJVAPCD Guideline 4.12.5 (see Reference 6 in Table D-4). The control efficiency can be met with a wet scrubber or equivalent technology. The VOC control efficiency is required in the permit for Reference 4 in Table D-4 and the ATC for Reference 2 in Table D-4. The limit was demonstrated in source tests for References 1, 3, and 5 in Table D-4.

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system (wet scrubber or equivalent technology) capable of 95 percent or better control efficiency.

F. Natural Gas-fired Boiler

1. Control of NO_x Emissions

Natural gas-fired boilers used in the production of biofuels are no different from similar-sized boilers used in other commercial and industrial processes. Biorefinery permits received by ARB staff included those for boilers as small as 4.9 MMBtu/hr and as large as 75.6 MMBtu/hr. The recommendations for boilers are broken down into several source categories based on boiler heat input rating. This is consistent with district rules and BACT guidelines, as the availability and cost of emission controls are dependent on boiler capacity.

Boiler Heat Rating 2 to <5 MMBtu/hr

The most stringent NO_x limits of 9 ppmvd (at 3 percent O₂) for an operational non-atmospheric natural gas-fired boiler and 12 ppmvd (at 3 percent O₂) for an operational atmospheric natural gas-fired boiler are required in SCAQMD Rule 1146.1 and SJVAPCD Rule 4307 (see References 1 and 2 in Table D-5) for boilers rated at 2.0 to less than 5.0 MMBtu/hr. The limits are based on emission levels achieved in practice by units located in these districts. Therefore, ARB staff has identified the most stringent NO_x limits as 9 ppmvd (at 3 percent O₂) for non-atmospheric boilers and 12 ppmvd (at 3 percent O₂) for atmospheric boilers rated at 2 to less than 5 MMBtu/hr.

Boiler Heat Rating 5 to <20 MMBtu/hr

The most stringent NOx limit for an operational natural gas-fired boiler rated at 5 to less than 20 MMBtu/hr is 6 ppmvd at 3 percent O₂ (or 0.007 lb/MMBtu) and is required in SJVAPCD Rule 4320 (see Reference 18 in Table D-5). This limit is on the Enhanced Schedule and is more stringent than the Standard Schedule limit of 9 ppmvd at 3 percent O₂. According to the District's Staff Report for this rulemaking¹⁶, the Enhanced Schedules were developed for boilers that could reach intermediate levels in the near future and then later achieve lower limits with more advanced technology. This allows operators to minimize their emissions by maximizing existing equipment and controls and postpone larger capital investments for selective catalytic reduction (SCR) or more advanced burners for the future. Therefore, the reason for the lower limits and extended compliance dates is not due to emission control technology constraints. New units must meet the applicable limits at the time of installation.

The next most stringent NOx limit for an operational natural gas-fired boiler rated at 5 to less than 20 MMBtu/hr is 9 ppmvd (at 3 percent O₂) and is required in SJVAPCD Rule 4306 (see Reference 4 in Table D-5) as an enhanced option. As discussed in Rule 4320 above, the enhanced option provides an extended compliance date in exchange for a lower NOx limit and is not due to emission control technology constraints.

Therefore, ARB staff has identified the most stringent NOx limit as 6 ppmvd (at 3 percent O₂) for boilers rated at 5 to less than 20 MMBtu/hr.

Boiler Heat Rating ≥20 MMBtu/hr

The most stringent NOx limit for an operational natural gas-fired boiler rated at 20 MMBtu/hr and greater is 5 ppmvd at 3 percent O₂ (or 0.0062 lb/MMBtu) and is required in SJVAPCD Rule 4320 (see Reference 18 in Table D-5). This limit is on the Enhanced Schedule and is more stringent than the Standard Schedule limit of 7 ppmvd at 3 percent O₂ (or 0.008 lb/MMBtu). As discussed above, the extended compliance dates allowed under the Enhanced Schedule provide additional time for operators to install advanced emission controls that require greater capital investment on existing units. New units are required to meet the applicable limits at the time of installation.

Boiler rules in the SCAQMD and BAAQMD further support the 5 ppmvd NOx limit for larger units. A natural gas-fired boiler rated at greater than or equal to 75 MMBtu/hr is required to meet 5 ppmvd (at 3 percent O₂) by SCAQMD Rule 1146 and BAAQMD Rule 9-7 (References 12 and 14 in Table D-5). In addition, a NOx limit of 7 ppmvd (at 3 percent O₂) or less is required as BACT in SCAQMD Guidelines for natural gas or propane-fired boilers rated at ≥20 MMBtu/hr (see Reference 8 in Table D-5) for units with add-on emission controls.

Therefore, ARB staff has identified the most stringent NOx limit as 5 ppmvd (at

¹⁶ SJVAPCD "Final Draft Staff Report" for Proposed New Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr), October 16, 2008.

3 percent O₂) for natural gas-fired boilers rated at greater than or equal to 20 MMBtu/hr.

2. Control of CO Emissions

CO is a product of incomplete combustion of hydrocarbon-based fuels. Generally speaking, there is an inverse relationship between CO and NO_x – when temperatures are lowered to meet NO_x requirements, the amount of CO increases. All of California is either attainment or unclassified for the State and federal CO ambient air quality standards. However, this is not the case for ozone, as the majority of California air basins are classified as nonattainment for the State standards. While the geographic scope of areas that are nonattainment for the federal standards is not as large, these areas of nonattainment generally correspond to the areas of the State with the highest population densities. Since NO_x is an ozone precursor, air regulatory programs have focused on maximizing NO_x reductions and have provided more flexible corresponding CO emission levels for combustion sources.

ARB staff noted that some CO requirements were specific to the type of boiler. The three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications are watertube, firetube, and cast iron. Field erected boilers are boilers that are constructed on site and comprise the larger watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Firetube boilers are used primarily for space heating systems, industrial process steam, and portable power boilers; they are almost exclusively packaged units, which are constructed off-site and shipped to the location where they are needed. The physical size of these units is constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Cast iron boilers are designed similar to firetube boilers but are constructed of cast iron rather than steel.

Boiler Heat Rating 2 to <250 MMBtu/hr

ARB staff found that the CO limits for boilers are consistent up to approximately 250 MMBtu/hr heat input rating. The most stringent CO limits of 50 ppmvd (at 3 percent O₂) for an operational firetube boiler and 100 ppmvd (at 3 percent O₂) for an operational watertube boiler are required as BACT in SCAQMD Guidelines for non-major source facilities (References 5 and 8 in Table D-5). The limits are based on emission levels achieved in practice by units located in the District. These levels are further supported by project-specific BACT requirements (References 3, 10, 11, 13, and 16 in Table D-5).

Therefore, ARB staff has identified the most stringent CO limits as 50 ppmvd (at 3 percent O₂) for firetube boilers and 100 ppmvd (at 3 percent O₂) for watertube boilers rated at 2 to less than 250 MMBtu/hr.

Boiler Heat Rating ≥250 MMBtu/hr

The most stringent CO limit for a boiler rated at greater than or equal to 250 MMBtu/hr is 10 ppmvd (at 3 percent O₂). This is deemed technologically feasible BACT in

BAAQMD BACT Guideline 17.3.1 and is achievable with add-on controls (e.g., oxidation catalyst). It should be noted that the 10 ppmvd limit may be required for boilers rated at less than 250 MMBtu/hr if an oxidation catalyst is found to be cost effective or is necessary to control TAC or VOC emissions.

Therefore, ARB staff has identified the most stringent CO limit as 10 ppmvd (at 3 percent O₂) for boilers greater than or equal to 250 MMBtu/hr.

3. Control of VOC Emissions

Similar to CO emissions, VOC emissions result from incomplete combustion. VOC emissions are released in the exhaust gas when some of the hydrocarbon fuel remains unburned or is partially burned during combustion. Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced VOC emissions. Like CO emissions, VOC emissions have traditionally been abated with combustion controls and oxidation catalysts. In addition, due to low VOC concentrations, the control of VOC emissions from natural gas-fired boilers has been less of a priority to regulators than control of NO_x and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions.

ARB staff obtained limited data on VOC emission levels from natural gas-fired boilers. In most cases, district BACT guidelines did not include an evaluation of BACT for VOC emissions or BACT was not triggered. In two cases, BACT for VOC was specified as use of gaseous fuels (References 10 and 15 in Table D-5). In two other project-specific cases, the BACT emission level for VOCs ranged from 0.003 lb/MMBtu to 0.0127 lb/MMBtu (References 3 and 13 in Table D-5). In both cases, no specific emission controls were applied to reduce VOC emissions. U.S. EPA's AP-42, Compilation of Air Pollutant Emission Factors, Table 1.4.2 (July 1998) lists a VOC emission factor of 5.5 lb/MMscf (or 0.005 lb/MMBtu) for natural gas combustion.

Due to the limited data set available for this Report, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of natural gas fuel for boilers in all heat input ratings, with the specific emission limit determined on a case-by-case basis for a given project. ARB staff recommends that stakeholders consult with the boiler manufacturer on guaranteed emission levels and evaluate VOC emission levels from AP-42, source tests, permits, and any new BACT guidelines or updates in determining the appropriate VOC limit.

4. Control of PM₁₀ Emissions

There are a limited number of options for controlling PM₁₀ emissions from combustion equipment. To date, the only control of boiler exhaust PM₁₀ emissions has been through limiting fuel type and sulfur content. Gaseous fuels are generally associated with the least PM₁₀ emissions due to their lower sulfur, nitrogen, and ash contents. BACT guidelines in the SCAQMD and BAAQMD specify use of natural gas fuel as

BACT for PM10 for boilers in various size ranges (References 5, 8, and 11 in Table D-5).

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of natural gas fuel for boilers in all heat input ratings.

5. Control of SOx Emissions

Fuel sulfur is the source of SOx emissions from boilers fired on gaseous fuels. Since the fuel sulfur content of natural gas is so low, the natural gas odorant substantially contributes to the fuel sulfur content. Since SOx emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Although an applicant can select a low-sulfur fuel, the applicant does not have control of fuel sulfur contents lower than that specified in contracts between gas utilities and gas suppliers. ARB's Guidance for Power Plant Siting and Best Available Control Technology (September 1999), determined that entities regulated by the California Public Utilities Commission have purchase contracts with an effective maximum of total sulfur content for natural gas of 1 grain per 100 standard cubic feet, or 1 gr/100 scf (approximately 17 ppmv sulfur). In addition, some districts have rules specifically limiting the sulfur content of fuels used in stationary sources. For example, SCAQMD Rule 431.1 (last amended June 12, 1998) limits the sulfur content of natural gas to 16 ppmv as hydrogen sulfide (H₂S).

Therefore, ARB staff has identified the most stringent SOx limit as the emission level corresponding to the use of natural gas with a sulfur content of no more than 1 gr/100 scf.

G. Pumps and Compressor Seals

1. Control of VOC Emissions

The most stringent VOC limit for pumps and compressor seals is 100 ppmvd (measured as methane) when measured by U.S. EPA Method 21 (see References 1 and 2 in Table D-8). This is required as technologically feasible BACT in BAAQMD BACT Guideline 137.1 for pumps and Guideline 48B.1 for compressors through use of double mechanical seals with barrier fluid, magnetically coupled pumps, canned pumps, magnetic fluid sealing technology or gas seal system vented to a thermal oxidizer or other approved control device, in connection with a District-approved quarterly inspection and maintenance program.

Therefore, ARB staff has identified the most stringent VOC limit as no leak of methane greater than 100 ppmvd in conjunction with the implementation of an inspection and maintenance program that checks for and repairs leaking components. BAAQMD Rule 8-18 and SJVAPCD Rule 4455 can be used as a model.

H. Valves, Flanges, and Other Connectors

1. Control of VOC Emissions

The most stringent VOC limit for valves, flanges, and other connectors is 100 ppmvd (measured as methane) when measured by U.S. EPA Method 21 (see References 1, 2, 3, and 4 in Table D-9). This is required as in the ATC for Reference 1 in Table D-9, and as achieved-in-practice BACT in SJVAPCD Guideline 4.12.1 and BAAQMD BACT Guideline 78.1.

Therefore, ARB staff has identified the most stringent VOC limit as no leak of methane greater than 100 ppmvd in conjunction with the implementation of an inspection and maintenance program that checks for and repairs leaking components. BAAQMD Rule 8-18 and SJVAPCD Rule 4455 can be used as a model.

I. Wet Cooling Tower

1. Control of PM10 Emissions

Cooling towers are heat exchangers used to dissipate large heat loads to the atmosphere. There are several types of cooling systems: once-through cooling, wet cooling, dry cooling, and hybrid cooling. Wet cooling has been the usual method of cooling at inland power plants in California and is the focus of discussion here. Because wet cooling towers provide direct contact between the cooling water and air passing through the tower, some of the liquid may be entrained in the air stream and carried out as “drift” droplets. These droplets generally contain the same chemical impurities as the water. Therefore, the particulate matter constituent of the drift droplets is treated as PM10 emissions.

ARB staff surveyed BACT requirements in districts with the most power plant activity – BAAQMD, SJVAPCD, and SCAQMD. In the BAAQMD, power plant BACT for cooling has been based on a wet system equipped with drift eliminators with a drift rate of 0.0005 percent of circulating water flow (Reference 2 in Table D-10). A cooling tower may be exempt from permit if it is not used for evaporative cooling of process water (water containing organics), it passes risk screening, and emits no more than 5 tons per year (tpy). The 5-tpy threshold was added in May 2000.¹⁷ Prior to that, power plant cooling towers were exempt from permit. In the SJVAPCD, District BACT Guideline 8.3.10 specifies technologically feasible PM10 BACT for an induced draft evaporative cooling tower as a cellular type drift eliminator (Reference 1 in Table D-10).

In the SCAQMD, cooling towers are exempt from permit unless they use contaminated water. If the cancer risk exceeds 1-in-a-million or hazard indices exceed 1.0, the exemption does not apply. Several contemporary combined-cycle power plant projects have not exceeded the District’s risk thresholds and have been exempt from permit, so BACT and offsets have not been required by the District. However, emission

¹⁷ Per BAAQMD Rule 2-1-319.1 (last amended March 4, 2009).

calculations are consistent with use of drift eliminators with a drift rate of 0.0005 percent of circulating water flow (Reference 3 in Table D-10). In addition, ARB staff found BACT determinations for cooling towers used at ethanol plants in the Midwest that also require use of drift eliminators with a drift rate of 0.0005 percent (References 4 and 5 in Table D-10).

Therefore, ARB staff has identified the most stringent PM₁₀ limit as the emission level corresponding to use of a drift eliminator with 0.0005 percent drift loss for wet cooling towers.

J. Natural Gas-Fired Dryer

1. Control of NO_x Emissions

The most stringent NO_x limit for a natural gas-fired dryer is 15 ppmvd at 3 percent O₂ (or 0.018 lb/MMBtu). This NO_x limit is identified as technologically feasible BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16). The limit is achievable with ultra low-NO_x burners.

Therefore, ARB staff has identified the most stringent NO_x limit as 15 ppmvd at 3 percent O₂ for natural gas-fired dryers.

2. Control of CO Emissions

The most stringent CO limit for a natural gas-fired dryer used at a biorefinery is 0.07 lb/MMBtu and is required in the permit for Reference 5 in Table D-16. At this facility, the dryer shares its exhaust stack with a biomass boiler. The next most stringent CO limit of 0.104 lb/MMBtu (approximately 141 ppmvd at 3 percent O₂) is required in the permit for Reference 4 in Table D-16. The emission control technology is not specified in the permit information received by ARB staff, and no corresponding source tests were available.

Therefore, while ARB staff has identified the most stringent CO limit as 0.07 lb/MMBtu for natural gas-fired dryers, regulatory agencies should evaluate the feasibility of this limit for specific applications due to the limited amount of information available at the time of this Report.

3. Control of VOC Emissions

The most stringent VOC limit for a natural gas-fired dryer is an emission limit corresponding to use of a VOC capture and control system with thermal or catalytic incineration or equivalent (98 percent control). This is identified as achieved-in-practice BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16).

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to use of a VOC capture and control system with thermal or catalytic

incineration or equivalent (98 percent control) for natural gas-fired dryers.

4. Control of PM10 Emissions

The most stringent PM10 limit for a natural gas-fired dryer is an emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series or equivalent (98.5 percent control). This is identified as achieved-in-practice BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16).

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series or equivalent (98.5 percent control) for natural gas-fired dryers.

5. Control of SOx Emissions

The most stringent SOx limit for a natural gas-fired dryer is an emission limit corresponding to use of a wet scrubber (95 percent control). This is identified as technologically feasible BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16).

Therefore, ARB staff has identified the most stringent SOx limit as the emission level corresponding to use of a wet scrubber (95 percent control) for natural gas-fired dryers.

K. Storage Tanks (Fixed Roof)

The most stringent VOC limit for a fixed roof storage tank is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is required in the ATC for Reference 1 in Table D-14. The control efficiency can be met with the use of vapor recovery routed to a distillation column and two-stage vapor condenser. The next most stringent VOC limit is an emission level corresponding to the use of a VOC control system with 99 percent control efficiency and is required as technologically feasible BACT in SJVAPCD Guideline 7.3.1 (Reference 2 in Table D-14). This guideline pertains to petroleum production, but could be applied as a technology transfer to a biorefinery.

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 99.5 percent or better control efficiency.

L. Storage Tanks (Floating Roof)

1. Control of VOC Emissions

The most stringent VOC limit for an external or internal floating roof storage tank is an emission level corresponding to the use of a VOC control system with 98 percent control efficiency. This is required as technologically feasible BACT in BAAQMD

Guideline 167.1.1 and Guideline 167.4.1 (Reference 1 in Table D-15). The control efficiency can be met by routing tank vapors to a thermal incinerator, carbon adsorber, refrigerated condenser, or District-approved equivalent technology.

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 98 percent or better control efficiency.

M. Flare (Ethanol Production)

1. Control of NO_x Emissions

The most stringent NO_x limit for a flare used in ethanol production is 0.05 lb/MMBtu. This NO_x limit is required in the permit for Reference 3 in Table D-13 and is achievable with a low-NO_x burner. The next most stringent NO_x limit of 0.068 lb/MMBtu (approximately 56 ppmvd at 3 percent O₂) is contained in the permits for References 5 and 6 in Table D-13 for both air assist and enclosed flares.

Therefore, ARB staff has identified the most stringent NO_x limit as 0.05 lb/MMBtu for loadout flares used in ethanol production.

2. Control of CO Emissions

The most stringent CO limit for a loadout flare used in ethanol production is 0.37 lb/MMBtu. This CO limit is required in the permits for References 5 and 6 in Table D-13 and is achievable for both air assist and enclosed flares. ARB staff was not able to acquire corresponding source tests for these or any other comparable sources. ARB staff noted that the corresponding CO limit for the flare with the 0.05 lb/MMBtu NO_x limit (see NO_x discussion above) is more than double the CO limit for the flares with the 0.068 lb/MMBtu NO_x limits. ARB staff assumes this could be due to the use of low-NO_x burners to meet the 0.05 lb/MMBtu NO_x limit and the inverse relationship between NO_x and CO combustion emissions. Without the benefit of source test data, ARB staff has some concerns about the ability to meet the 0.05 lb/MMBtu NO_x limit in conjunction with a 0.37 lb/MMBtu CO limit.

Therefore, while ARB staff has identified the most stringent CO limit as 0.37 lb/MMBtu for loadout flares used in ethanol production, ARB staff acknowledges that regulatory agencies could consider a higher CO limit as a trade-off for a lower NO_x limit, especially in ozone nonattainment areas and in cases where BACT for CO is not triggered.

3. Control of VOC Emissions

The most stringent VOC limit for a loadout flare used in ethanol production is 0.063 lb/MMBtu. This VOC limit is required in the permits for References 5 and 6 in Table D-13 and is achievable for both air assist and enclosed flares.

Therefore, ARB staff has identified the most stringent VOC limit as 0.063 lb/MMBtu for loadout flares used in ethanol production.

4. Control of PM10 Emissions

The most stringent PM10 limit for a loadout flare used in ethanol production is 0.008 lb/MMBtu. This PM10 limit is required in the permit for Reference 5 in Table D-13.

Therefore, ARB staff has identified the most stringent PM10 limit as 0.008 lb/MMBtu for loadout flares used in ethanol production.

5. Control of SOx Emissions

The most stringent SOx limit for a loadout flare used in ethanol production is 0.00285 lb/MMBtu. This SOx limit is required in the permit for Reference 5 in Table D-13.

Therefore, ARB staff has identified the most stringent SOx limit as 0.00285 lb/MMBtu for loadout flares used in ethanol production.

N. Liquid Fuel Loading Operations

1. Control of VOC Emissions

The most stringent VOC limit for liquid fuel loading operations is an emission level corresponding to the use of a VOC control system with 98 percent control efficiency. This is required in the permit for Reference 4 in Table D-18. The control efficiency can be met with a carbon adsorption canister. Other permits for ethanol loading and unloading operations require the use of a carbon adsorber to reduce VOC emissions, along with maximum leak rates (References 3 and 5 in Table D-18).

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 98 percent or better control efficiency.

O. Liquid Fuel Transfer and Dispensing Operations

1. Control of VOC Emissions

ARB is responsible for certifying vapor recovery systems used at gasoline service stations, bulk plants, terminals, cargo tanks, and novel facilities. In the process of certifying vapor recovery systems, ARB establishes performance standards and specifications for systems and their components. Districts have the primary responsibility of regulating emissions from stationary sources such as gas stations. To this end, districts have adopted rules that require gasoline storage and transfer

operations to be equipped with vapor recovery systems certified by ARB.

Vapor recovery systems collect gasoline vapors that would otherwise escape into the atmosphere during fuel delivery to the underground storage tanks (Phase I) or fuel storage and vehicle fueling (Phase II). ARB staff assumes that district rules requiring vapor recovery equipment are applicable to biofuel blends that meet the definition of “gasoline” as defined in district rules (generally these definitions pertain to the vapor pressure of the fuel).

ARB has certified a number of Phase I and II systems for gasoline. However, a biofuel blend such as E-85 requires a separate certification. To date, ARB has certified an E-85 compatible Phase I vapor recovery system designed for use with underground storage tanks. ARB has not yet certified a Phase I E-85 vapor recovery system for aboveground tanks or a Phase II E-85 vapor recovery system for underground or aboveground tanks.

Many local air districts have deemed E-85 fueling facilities exempt from Phase II vapor recovery because they are used to fuel newer vehicles which are equipped with On-Board Refueling Vapor Recovery (ORVR). For example, Monterey Bay Unified Air Pollution Control District Rule 1002 exempts facilities from Phase II vapor recovery which can demonstrate at least 90 percent of the vehicles fueled at the facility are owned by a common operator and are equipped with ORVR. SCAQMD Rule 461 exempts non-retail gasoline dispensing facilities from Phase II vapor recovery requirements until April 1, 2012 (Reference 1 in Table D-20). Rule 461’s ORVR exemption only applies to non-retail gasoline dispensing facilities whose fleet vehicles are 100 percent ORVR.

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to use of an ARB certified Phase I vapor recovery system and ARB certified Phase II vapor recovery system (unless exempt by applicable local air district rule) to reduce VOC emissions from liquid fuel transfer and dispensing operations using biofuel blends that are subject to local district requirements.

P. Biomass-Fired Boilers

ARB staff found that biorefineries that require heat or steam for the production process almost exclusively use natural gas-fired boilers. However, staff did locate one cellulosic ethanol plant in California that proposed to use an 85 MMBtu/hr (approximately 25 MW) biomass (lignin)-fired boiler. Therefore, although not commonplace in California¹⁸, ARB staff has included biomass-fired boilers as a category of equipment that may be used at biorefineries. ARB staff noted that emission standards for biomass boilers were typically bifurcated at the 10 to 25 MW boiler rating level. Since ARB staff expects biomass boilers used in biofuel production to be rated at greater than 10 MW, this

¹⁸ ARB staff has received data through the LCFS carbon intensity pathway evaluation process for out-of-state biofuel facilities with energy sources that co-fire with biomass. Staff will examine the emission rates for biomass co-fired boilers in the next Report update.

section evaluates the emission limits for units of this size. However, Appendix D includes some data on biomass boilers less than 10 MW for informational purposes.

1. Control of NO_x Emissions

The most stringent NO_x limit for a biomass-fired boiler is 0.012 lb/MMBtu (approximately 9 ppmvd at 3 percent O₂). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using selective non-catalytic reduction (SNCR), SCR, wet scrubber, and natural gas auxiliary fuel. This limit is also consistent with technologically feasible BACT guidance from the Massachusetts Department of Environmental Protection (MDEP). MDEP's BACT Guidance for Biomass Projects dated April 18, 2007, for biomass-fired boilers rated at 10 MW or greater recommends a NO_x limit of 0.015 lb/MMBtu (approximately 12 ppmvd at 3 percent O₂).

The next most stringent NO_x limit for an operational biomass-fired boiler is 0.075 lb/MMBtu (approximately 58 ppmvd at 3 percent O₂). This NO_x limit is deemed achieved in practice BACT by the SJVAPCD and MDEP (References 4 and 7 in Table D-6). The limit was also required as BACT in the permit for Reference 3 in Table D-6. The achievability of the limit was substantiated in source tests for References 11 and 12 in Table D-6. All of the referenced boilers employ a circulating fluidized bed and are equipped with SNCR for NO_x control.

Therefore, ARB staff has identified the most stringent NO_x limit as 0.012 lb/MMBtu for biomass-fired boilers.

2. Control of CO Emissions

The most stringent CO limit for a biomass-fired boiler is 0.01 lb/MMBtu (approximately 13 ppmvd at 3 percent O₂). This limit is categorized as technologically feasible BACT in the MDEP's BACT Guidance for Biomass Projects dated April 18, 2007, for biomass-fired boilers rated at 10 MW or greater. The CO limit is based on applying an oxidation catalyst and the assumption that the same level of emission reduction that has been achieved on other fuel sources will be achieved using biomass fuels. The Guidance states that the agency considers this a starting point for a BACT analysis and will consider alternative limits if the applicant can demonstrate that the limit is not technically feasible.

The next most stringent CO limit for a biomass-fired boiler is 0.046 lb/MMBtu (approximately 59 ppmvd at 3 percent O₂). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using an oxidation catalyst and good combustion practices. It should be noted that, although BACT was not triggered, the oxidation catalyst was proposed by the

applicant.¹⁹ Therefore, this reflects an achievable permit limit based on the equipment and add-on controls proposed for this project; it does not reflect a project-specific BACT analysis for CO.

Available permit data for existing biomass boilers in California and information from Babcock & Wilcox Power Generation Group²⁰ indicates CO emissions from circulating fluidized-bed (CFB) boilers are lower than stoker boilers. Therefore, for example, because the baseline exhaust CO emissions from a stoker boiler are higher than from a CFB boiler, applying an oxidation catalyst that achieves an 80 percent reduction will still result in higher CO stack emissions from the stoker unit. With the exception of CO, the most stringent limits for all other pollutants identified by ARB staff for biomass-fired boilers come from a stoker boiler at a single facility (Reference 6 in Table D-6). Due to different expected emissions performance results based on boiler firing technology, ARB staff believes we do not have sufficient data at the drafting of this Report to determine that the most stringent CO limit of 0.01 lb/MMBtu is achievable in conjunction with the other pollutant limits.

Therefore, ARB staff has identified the most stringent CO limit as 0.046 lb/MMBtu (at 3 percent O₂) for biomass-fired boilers. However, ARB staff also recommends that regulatory agencies evaluate the feasibility of meeting a CO limit of 0.01 lb/MMBtu, particularly if the applicant is proposing a new CFB-type boiler.

3. Control of VOC Emissions

The most stringent VOC limit for a biomass-fired boiler is 0.005 lb/MMBtu (approximately 11 ppmvd as CH₄ at 3 percent O₂). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using an oxidation catalyst, good combustion practices, and natural gas auxiliary fuel.

Therefore, ARB staff has identified the most stringent VOC limit as 0.005 lb/MMBtu for biomass-fired boilers.

4. Control of PM10 Emissions

The most stringent PM10 limit for a biomass-fired boiler is 0.024 lb/MMBtu (approximately 0.01 gr/dscf at 12 percent CO₂). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using a multiclone and electrostatic precipitator (ESP).

¹⁹ In SJVAPCD, BACT for CO is triggered if the potential to emit exceeds 2.0 lbs/day and the facility-wide potential to emit is 200,000 lbs/yr or greater.

²⁰ Babcock & Wilcox Power Generation Group, Inc. publication, *Bubbling Fluidized-Bed Boilers: Burning Biomass and Low-Cost Fuels*, 2008, <http://www.babcock.com/library/pdf/E1013161.pdf>.

Available permit data for existing biomass boilers in California shows these units are equipped with various types of particulate control devices including multiclones, baghouses, and ESPs. Permitted limits range from 0.01 to 0.2 gr/dscf (at 12 percent CO₂). The PM₁₀ emission values most likely vary because of differing sampling methods used. Available data indicate the highest level of PM₁₀ control is from an ESP. Facilities equipped with ESPs have source test data demonstrating PM₁₀ emissions as low as 0.0005 gr/dscf (at 12 percent CO₂) (0.001 lb/MMBtu) as shown in the source test for Reference 12 in Table D-6.

While the source test methods used report emissions as PM₁₀ or total solid particulates, ARB PM size fraction data indicates 99.7 percent of emissions from combustion in a wood-fired boiler is PM₁₀ or less. Available data also indicate that units can meet a total (filterable and condensable) PM₁₀ limit of 0.01 gr/dscf (see References 10, 12, and 13 in Table D-6).

Therefore, ARB staff has identified the most stringent PM₁₀ limit as 0.01 gr/dscf at 12 percent CO₂ or 0.024 lb/MMBtu for biomass-fired boilers.

5. Control of SO_x Emissions

The most stringent SO_x limit for a biomass-fired boiler is 0.012 lb/MMBtu (approximately 7 ppmvd at 3 percent O₂). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using trona injection and natural gas auxiliary fuel. The SJVAPCD determined that trona injection²¹ provides SO_x control at least equivalent to limestone injection.

Therefore, ARB staff has identified the most stringent SO_x limit as 0.012 lb/MMBtu for biomass-fired boilers.

Q. Landfill Gas-Fired Flare

a. Control of NO_x Emissions

The most stringent NO_x limit for a landfill gas-fired flare is 0.025 lb/MMBtu. This NO_x limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare.

Therefore, ARB staff has identified the most stringent NO_x limit as 0.025 lb/MMBtu for landfill gas-fired flares.

²¹ Trona is a mineral with the natural form of sodium sesquicarbonate. It has many applications in neutralizing acidic gases. Trona is rapidly calcined to sodium carbonate when heated at or above 275 °F. The popcorn-like crystal structure change in trona creates a large and reactive surface for adsorption and neutralization with acidic gases.

b. Control of CO Emissions

The most stringent CO limit for a landfill gas-fired flare is 0.06 lb/MMBtu. This CO limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare.

Therefore, ARB staff has identified the most stringent CO limit as 0.06 lb/MMBtu for landfill gas-fired flares.

c. Control of VOC Emissions

The most stringent VOC limit for a landfill gas-fired flare is 98 percent destruction efficiency or 20 ppmvd at 3 percent O₂. This VOC limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare. It is also listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.3 (Reference 2 in Table D-11).

Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to 98 percent destruction efficiency or 20 ppmvd at 3 percent O₂ for landfill gas-fired flares.

d. Control of PM₁₀ Emissions

The most stringent PM₁₀ limit for a landfill gas-fired flare is an emission limit corresponding to use of steam injection and/or knockout vessel. Use of steam injection is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.3 (Reference 1 in Table D-11) for an enclosed flare. Use of an external force such as steam injection or blowing air is used for efficient air/waste gas mixing which promotes smokeless flaring. Use of a knockout vessel is listed as BACT in SCAQMD BACT Guidelines for Non-Major Facilities (Reference 3 in Table D-11). Liquid in the process gas stream can extinguish the flame or cause irregular combustion and smoking. A knockout vessel is located at the base of the flare or inside the base of the flare stack and is used to remove liquids in the gas stream.

Therefore, ARB staff has identified the most stringent PM₁₀ limit as the emission level corresponding to use of steam injection and/or knockout vessel for landfill gas-fired flares.

e. Control of SO_x Emissions

The most stringent SO_x limit for a landfill gas-fired flare is an emission limit corresponding to use of a wet scrubber with 98 percent control efficiency. This is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.3 (Reference 1 in Table D-11) for an enclosed flare.

Therefore, ARB staff has identified the most stringent SO_x limit as the emission level

corresponding to use of a wet scrubber with 98 percent control efficiency for landfill gas-fired flares.

R. Manure Digester and Co-Digester Gas-Fired Flare

1. Control of NO_x Emissions

The most stringent NO_x limit for a digester gas-fired flare is 0.03 lb/MMBtu. This NO_x limit is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired flare equipped with ultra low-NO_x burners (Reference 1 in Table D-12). The limit is also required as technologically feasible BACT in SJVAPCD Guideline 2.2.3 for a cheese wastewater-fired flare using ultra low-NO_x burners.

Therefore, ARB staff has identified the most stringent NO_x limit as 0.03 lb/MMBtu for digester gas-fired flares.

2. Control of CO Emissions

ARB staff was unable to obtain any specific information regarding CO emissions performance for digester gas-fired flares. The most stringent CO requirement staff found for a digester gas-fired flare is operation of the flare per manufacturer specifications to minimize CO. This is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare (Reference 2 in Table D-12). However, ARB staff expects that digester gas-fired flares should be able to achieve comparable CO emissions as the other flares listed in this Report.

Therefore, ARB staff recommends a CO limit of consistent with operation of the flare per manufacturer specifications to minimize CO for digester gas-fired flares.

3. Control of VOC Emissions

The most stringent VOC limit for a digester gas-fired flare is 0.03 lb/MMBtu and is required as technologically feasible BACT in SJVAPCD Guideline 1.4.6 for a biogas-fired limited use flare (Reference 3 in Table D-12). The next most stringent VOC limit is 0.068 lb/MMBtu. This VOC limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare (Reference 2 in Table D-12).

Therefore, ARB staff has identified the most stringent VOC limit as 0.03 lb/MMBtu for digester gas-fired flares. However, regulatory agencies should assess whether the limited use flare constitutes a different class or category of source for purposes of determining the lowest feasible VOC emission level for their particular flare application.

4. Control of PM₁₀ Emissions

The most stringent PM₁₀ limit for a digester gas-fired flare is an emission limit corresponding to use of smokeless combustion and an liquefied petroleum gas (LPG) or

natural gas-fired pilot. A smokeless flare uses compressed air that is pumped into the flame and burning gas, using a special nozzle system. The air/waste gas mixing improves combustion and reduces smoking. This is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare and as technologically feasible BACT in SJVAPCD Guideline 2.2.3 for a cheese wastewater-fired enclosed flare (References 1 and 4 in Table D-12).

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of smokeless combustion and an LPG or natural gas-fired pilot for digester gas-fired flares.

5. Control of SOx Emissions

The most stringent SOx limit for a digester gas-fired flare is an emission limit corresponding to use of an H₂S removal system (dry or wet scrubber or equivalent). This is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired flare and Guideline 2.2.3 for a cheese wastewater-fired flare (References 1 and 4 in Table D-12).

Therefore, ARB staff has identified the most stringent SOx limit as the emission level corresponding to use of an H₂S removal system (dry or wet scrubber or equivalent) for digester gas-fired flares.

S. Compressed Gas Dispensing Operations

ARB staff identified permits for two compressed gas dispensing operations. The operations consist of biogas treating, compression, and dispensing equipment to collect and treat landfill gas to produce CNG for vehicles. At both facilities, there are no direct emissions associated with the equipment. These are closed loop systems with all vent and excess process gas being directed to the on site treatment system, used in vehicles, or directed to another combustion (e.g., flare) or processing facility that can process the biogas and which has been issued a valid district permit.

T. Combustion of Biogas

ARB staff has found that production of biofuels for transportation from anaerobic digestion is a co-product of a larger system put in place to manage a waste stream such as at a landfill, wastewater treatment plant, or dairy. This section is intended to address emissions from the point where the biogas from anaerobic digestion has been treated to the level necessary to remove impurities for proper operation of downstream equipment and associated pollution control equipment. Therefore, this section does not identify or recommend emission limits for any stationary source pollutant-emitting equipment *prior* to the combustion of the biogas to generate electricity or produce transportation fuels.

ARB staff found that facilities that use biogas for transportation fuels may also use a portion of the biogas for energy production in reciprocating internal combustion engines

or turbines. Additional excess biogas is generally flared. Fuel cells can also be used to produce energy from biomass. The emissions performance of these types of electrical generating units, as well as flares, is addressed below.

1. Biogas Treatment

Biogas created from the anaerobic digestion of biomass is typically composed of about 50 percent CH₄, 50 percent CO₂, very small amounts of non-methane organic compounds, and other contaminants. Due to the adverse effects of biogas contaminants, gas treatment is required prior to use in a fuel cell, boiler, reciprocating IC engine, or turbine. Contaminants found in biogas include H₂S and a variety of other corrosive gases from chemical products in the waste. Sewage digester and landfill gas also contain siloxanes, which are silica-based compounds from various consumer products in the waste stream. Some of the specific components of waste and biogas and their operational challenges include:

- Solids, which can cause erosion of critical surfaces or plugging of orifices.
- Water, which retards combustion and can cause erosion, corrosion, or catastrophic damage to critical surfaces or components;
- Non-methane fuel components (butane, propane, CO, hydrogen), which can change combustion characteristics; if present in liquid form can cause physical damage;
- Sulfur and sulfur compounds, which can cause corrosion in engines, increase maintenance requirements (more frequent overhauls and oil changes), and poison catalytic materials;
- CO₂, which reduces heating value and combustibility; and
- Siloxanes, which create a glassy deposition on high-temperature surfaces; particles can break off and damage working parts.

Typical treatments remove moisture, CO₂, sulfur compounds, particulates, and other impurities. Siloxane removal is typically accomplished with adsorption beds. Additional treatment technologies that have been applied to oil field and landfill gas should be evaluated for feasibility to transfer to other types of biogas. These use a variety of gas separation technologies that rely upon physical, biological, and/or chemical filtration.

Biogas which has been upgraded to remove the bulk of the carbon dioxide, water, hydrogen sulfide, and other impurities from raw biogas is termed “biomethane.” The primary purpose of upgrading biogas to biomethane is to use the biomethane as an energy source in applications that require pipeline quality or vehicle-fuel quality gas, such as transportation. For the purposes of this Report, ARB staff is using the term biogas to describe biogas that has undergone some level of treatment to remove impurities – regardless of whether the level of treatment would produce a product gas that would fit the definition of biomethane.

2. Distributed Generation Subject to ARB Certification (NO_x, CO, and VOC Emission Standards)

Distributed Generation (DG) refers to electrical generation near the place of use. In California, every DG unit must be certified by the ARB or permitted by a local district. Permit exemption levels vary among California's 35 air districts; although permitting thresholds tend to be low, especially in non-attainment areas. Therefore, DG subject to the ARB's certification program tend to be small generating units. Examples of the technologies typically subject to the DG certification program include microturbines up to 250 kW, reciprocating IC engines under 50 brake horsepower (bhp), external combustion engines, and fuel cells. Biomass-fueled DG equipment typically operate on biogas. Detailed information on ARB's DG Certification Program can be found at <http://www.arb.ca.gov/energy/dg/dg.htm>.

The DG Program specifies emission standards for NO_x, CO, and VOC. Table V-1 summarizes the ARB's DG certification emission standards for waste gas-fired units²². The 2013 standards represent BACT for natural gas-fired central station power plants. These reflect the directive of the enabling legislation, Senate Bill 1298, which required that DG equipment in California must meet central station power plant emission standards "at the earliest practicable date." DG units that produce combined heat and power (CHP) may take advantage of a credit to meet the 2013 standards.

Table IV-1. Waste Gas Emissions Standards for DG Certified by ARB

Pollutant	Emission Standard (lb/MW-hr)	
	On or after January 1, 2008	On or after January 1, 2013
NO _x	0.5	0.07
CO	6.0	0.10
VOC	1.0	0.02

It should be noted that only DG fueled by waste gas that meets the regulatory definition can be certified by ARB. At this time, digester gas originating from dairy manure is not included in the definition of waste gas. Therefore, all dairy manure digester gas-fueled DG equipment is subject to the permitting requirements of the air district.

a. Fuel Cells

A fuel cell is an electrochemical device that combines hydrogen with oxygen to produce electricity, heat, and water. The hydrogen can be supplied through a tank or a reformer that extracts the hydrogen from a fossil fuel, such as natural gas. Although no companies that produce waste gas fuel cell technologies have requested certification by ARB, available data shows that the technology is able to meet the 2013 NO_x and CO standards. In the two available source tests for VOC, one site met the 2008 standard

²² Waste gases, as defined in the regulation, include gases produced from the decomposition of sewage, gases produced from the decomposition and volatilization of materials in landfills, and gases produced from the drilling of oil wells and pumping of oil from wells that are not eligible for delivery to the utility pipeline system.

and the other met the 2013 standard. Source tests demonstrating compliance with the emission standards are given in References 3, 5, and 6 in Table D-7 for units using landfill and sewage digester gas.

Because the performance of currently operating fuel cells is well below the January 1, 2008 emission standards, ARB staff recommends that regulatory agencies consider the 2013 limits of 0.07 lb/MWh NO_x, 0.10 lb/MWh CO, and 0.02 lb/MWh VOC for biogas-fueled fuel cells. In no event should the limits for biogas fuel cells exceed 0.5 lb/MWh NO_x, 6.0 lb/MWh CO, and 1.0 lb/MWh VOC.

b. Microturbines

California air districts typically require a permit for gas turbines as small as 300 kW. Microturbines are high-speed, single-rotor turbines that are usually less than 300 kW in size. They can operate alone or in parallel with a number of units.

To date, the ARB has issued six certifications for waste gas applications. These include a 65 kW Capstone CR65 microturbine using both landfill and sewage digester gas, a 250 kW Ingersoll Rand 250SW microturbine using landfill gas, a 250 kW Ingersoll Rand 250ST microturbine using sewage digester gas, a 65 kW Capstone C65 High Btu microturbine using oil field gas, and a 250 kW Capstone CR200 Medium Btu microturbine using sewage digester gas. The units are certified to comply with the 2008 DG waste gas emission standards in Table V-1. Emission data showing compliance with the standards for waste gas is included as References 1, 2, 3, and 4 in Table D-21. The composition of the surrogate sewage digester gas used for the certification is 60 to 65 percent CH₄ and 35 to 40 percent CO₂ by volume, which is similar to manure digester gas. The presence of other contaminants is only expected to affect the type of gas pretreatment required (e.g., siloxane removal from sewage digester gas and likely more H₂S removal from manure digester gas).

Experience to date with microturbines run on dairy biogas indicates the most common problem is compressor failure. Compressors are separate equipment, but are required to increase the biogas to the required pressure for operation of the microturbines. It appears that the cause of compressor failure is lack of biogas pretreatment to remove H₂S and moisture. Therefore, the acceptable level of H₂S to prevent compressor failure needs to be determined for each application.

Consistent with the DG Certification Program, ARB staff recommends limits of 0.5 lb/MWh NO_x, 6.0 lb/MWh CO, and 1.0 lb/MWh VOC for biogas-fired microturbines. On and after January 1, 2013, ARB staff recommends limits of 0.07 lb/MWh NO_x, 0.10 lb/MWh CO, and 0.02 lb/MWh VOC for biogas-fired microturbines

3. Distributed Generation Requiring District Permit

a. Reciprocating IC Engines

The IC engines addressed in this section of the Report are piston-type (also known as reciprocating) spark-ignited IC engines. Spark-ignited IC engines can use natural gas, landfill gas, digester gas, field gas, refinery gas, propane, methanol, ethanol, gasoline, or a mixture of these fuels. Reciprocating IC engines are generally classified as either four or two stroke. Another basis engine parameter is the air/fuel ratio. Stoichiometry is defined as the precise air-to-fuel ratio where sufficient oxygen is supplied to completely combust fuel. Rich of stoichiometry refers to fuel-rich combustion; lean of stoichiometry refers to fuel-lean combustion. Two-stroke, spark-ignited engines are lean-burn, while naturally aspirated, four-stroke spark-ignited engines are generally rich-burn.

i. Control of NO_x Emissions

Landfill Gas and Digester Gas

The most stringent NO_x limit for a landfill- or digester gas-fired reciprocating IC engine is 11 ppmvd at 15 percent O₂. This NO_x limit is required by SCAQMD Rule 1110.2, effective July 1, 2012. When Rule 1110.2 was amended in 2008 to include this limit for waste gas-fired reciprocating IC engines, the rule called for a Technology Assessment by July 2010 to verify the feasibility of available control technologies.²³ On July 9, 2010, the SCAQMD issued an Interim Report on Technology Assessment for Biogas Engines Subject to Rule 1110.2, which summarizes District staff's technology assessment and findings to date, including the status of three on-going demonstration projects, which experienced significant delays due to the permit moratorium in 2009, and will be followed by another report upon completion of the technology demonstration projects.

In July 2011, the District released the final report on pilot testing of a sewage digester gas-fired engine (supplemented with natural gas) retrofitted with a digester gas cleaning system, catalytic oxidizer, and SCR system with urea injection.²⁴ The average NO_x concentration at the stack exhaust after the pilot study controls was approximately 7 ppmv, below the 11 ppmv required under amended Rule 1110.2. The lowest NO_x stack exhaust concentration met consistently under all valid conditions was 16 ppmv. While there were some periods (i.e., 15-minute block averages) where the NO_x stack exhaust concentration was above 11 ppmv, after screening these periods, 181 periods out of 21,285 total operating periods (approximately 5,321 hours) remained as valid NO_x excursions above the Rule 1110.2 limit. These periods occurred during 61 separate events and accounted for less than 0.9% of the total measurement periods during the pilot study. Excursions were considered valid when they occurred during periods/events when the percentage of natural gas increased to above 5% of the fuel

²³ Rule 1110.2 establishes emission limits for NO_x, CO, and VOC.

²⁴ Malcolm Pirnie, The Water Division of ARCADIS, "Final Report: Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology: Pilot Testing of Emission Control System Plant 1 Engine 1," Orange County Sanitation District Project No. J-79, SCAQMD Contract #10114, July 2011, <http://www.aqmd.gov/rules/proposed/1110-2/OCSDPilotStudy.pdf>.

blend, when engine loads exceeded the loads mapped during the SCR system commissioning, or during periods/events not attributable to engine start-up or operational /system adjustments. District staff is currently evaluating the data and could adjust the 11 ppmv limit and/or adjust the averaging time to address the excursion issue. District staff expects to bring amendments to Rule 1110.2 to their Governing Board for consideration in spring 2012. Due to the time involved in implementing the demonstration projects, the amendments may also include an adjustment to the July 1, 2012, compliance date in the rule.

Landfill Gas

The second most stringent NOx limit for an operational landfill gas-fired reciprocating IC engine is 0.5 g/bhp-hr. This NOx limit is required in the permit for Reference 7 in Table D-22 using lean-burn/turbocharged engine technology. Several source tests demonstrating compliance with the NOx limit at this site are included in Appendix D, Table D-22. However, past source test data indicates there have been some problems meeting the NOx, CO, and VOC permit limits. The third most stringent NOx limits of 0.5 and 0.6 g/bhp-hr for landfill gas-fired reciprocating IC engines are contained in the permits for References 4, 20, 21, 22, 24, 26, and 27 in Table D-22. Additional source tests show compliance with the 0.5 and 0.6 g/bhp-hr emission levels, and are available in Table D-22.

Sewage Digester Gas

The second most stringent NOx limit for an operational sewage digester gas-fired reciprocating IC engine is 0.5 g/bhp-hr. This NOx limit is required in the permit for Reference 7 in Table D-23 using lean-burn, turbocharged, and aftercooled engine technology. Three source tests demonstrating compliance with the NOx limit at various wastewater treatment plants are included in Appendix D, Table D-23. The third most stringent NOx limit of 0.6 g/bhp-hr is contained in the permits for References 3 and 4 in Table D-23.

Manure Digester and Co-Digester Gas

Dairy manure digester and co-digester gas-fired reciprocating IC engines triggering BACT requirements in the San Joaquin Valley have been required to meet a NOx BACT limit consistent with SCAQMD Rule 1110.2. The SJVAPCD currently considers a NOx limit of 0.15 g/bhp-hr as BACT for dairy digester gas-fired reciprocating IC engines. Depending on efficiency assumptions, this is equivalent to approximately 9 to 11 ppmvd at 15 percent O₂. The District is currently using 9.0 ppmvd as BACT for rich-burn reciprocating IC engines and 11 ppmvd as BACT for lean-burn reciprocating IC engines. The NOx limit of 9.0 ppmvd at 15 percent O₂ is required in the permit for a dairy manure and cheese waste rich burn digester gas-fired reciprocating IC engine equipped with 3-way nonselective catalytic reduction (Reference 7 in Table D-24). A recent source test demonstrated compliance with 9.0 ppmvd at 15 percent O₂ (Reference 8 in Table D-24). The NOx limit of 11.0 ppmvd at 15 percent O₂ is required in the ATC for a dairy digester gas-fired reciprocating IC engine (Reference 2 in Table D-24) using lean-burn technology and SCR. The lean-burn engine permit includes a 24-month trial period to reduce NOx to the target 0.15 g/bhp-hr. The final NOx BACT limit will be

determined by the District after 24 months of operating history, but in no way can exceed 0.60 g/bhp-hr.

The second most stringent NO_x limit for an operational dairy manure digester gas-fired reciprocating IC engine is 47 ppmvd (at 15 percent O₂) or 0.9 g/bhp-hr (Reference 4 in Table D-24). The ARB's July 2002 Guidance for the Permitting of Electrical Generation Technologies (DG BACT Guidance) recommended 0.6 g/bhp-hr (50 ppmvd at 15 percent O₂) as BACT for NO_x from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22). BAAQMD achieved-in-practice BACT guidance requires 0.5 to 0.6 g/bhp-hr as BACT for NO_x from landfill gas-fired reciprocating IC engines greater than 250 bhp using lean-burn technology (References 29 and 30 in Table D-22). BAAQMD achieved-in-practice BACT guidance requires 0.5 to 0.6 g/bhp-hr as BACT for NO_x from landfill gas-fired reciprocating IC engines greater than 250 bhp using lean-burn technology (References 29 and 30 in Table D-22)

The combination of permit limits and source test data in Appendix D for waste gas-fired reciprocating IC engines indicate NO_x levels of 36 ppmvd (at 15 percent O₂) or less are achievable for waste gas derived from landfills, wastewater treatment plants, and dairy digesters. The additional source test from a co-digester gas-fired engine demonstrates that even lower levels can be achieved with post-combustion, add-on emission controls. The corresponding g/bhp-hr limits vary based on the efficiency of each engine (from 0.2 to 0.6 g/bhp-hr). In addition, the initial results of the SCAQMD Rule 1110.2 Technology Assessment have found that two approaches appear capable of achieving compliance with the rule limits: (1) application of SCR for NO_x reduction and catalytic oxidation of CO and VOC together with biogas treatment upstream of the engine to remove catalyst fouling impurities and (2) application of a non-catalytic technology known as NO_xTech that reduces NO_x, VOC, and CO.

Nonselective catalytic reduction (NSCR) is applicable to all rich-burn IC engines. NSCR catalysts are often called 3-way catalysts because CO, VOC, and NO_x are simultaneously controlled. Removal efficiencies for a 3-way catalyst are greater than 90 percent for NO_x, greater than 80 percent for CO, and greater than 50 percent for VOC. SCR is applicable to all lean-burn IC engines. The exhaust of lean-burn IC engines contains high levels of oxygen and relatively low levels of VOC and CO, which make an NSCR type of catalyst ineffective at reducing NO_x. However, an SCR catalyst can be highly effective under these conditions. The NO_x removal efficiency of SCR is typically above 80 percent when within the catalyst temperature window. Therefore, ARB staff has identified the most stringent NO_x limit as 11 ppmvd at 15 percent O₂ (or 0.15 g/bhp-hr)²⁵, and staff recommends that this limit be evaluated as a technologically feasible NO_x emission limit for all digester and landfill gas reciprocating IC engines in conjunction with an effective and efficient biogas treatment system.

²⁵ Due to the experience at Gallo Cattle Company in Atwater, CA, regulatory agencies should evaluate 9 ppmvd at 15 percent O₂ for rich-burn dairy digester gas-fired engines.

ii. Control of CO Emissions

Landfill Gas

The most stringent CO limit for an operational landfill gas-fired reciprocating IC engine is 0.3 g/bhp-hr (approximately 37 ppmvd at 15 percent O₂). This CO limit is required in the permit for Reference 4 in Table D-22. ARB staff found two source tests demonstrating compliance with this CO limit (References 5 and 25 in Table D-22). However, several other source tests show much higher CO emission levels. The next most stringent CO limit of 250 ppmvd at 15 percent O₂ (2.0 g/bhp-hr) is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-22). Table D-22 contains several source tests demonstrating compliance with this limit.

Sewage Digester Gas

The most stringent CO limit for a sewage digester gas-fired reciprocating IC engine is 250 ppmvd at 15 percent O₂ (2.0 g/bhp-hr). This CO limit is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-23). Two source tests demonstrating compliance with the CO limit at a wastewater treatment plant are included in Appendix D, Table D-23 (References 5 and 6).

Manure Digester and Co-Digester Gas

The most stringent CO limit for a manure digester or co-digester gas-fired reciprocating IC engine is 210 ppmvd at 15 percent O₂ (1.75 g/bhp-hr). This CO limit is required in the permit for Reference 2 in Table D-24. The next most stringent CO limit of 250 ppmvd at 15 percent O₂ (2.0 g/bhp-hr) is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-24).

The ARB's 2002 DG BACT Guidance recommended a CO limit of 300 ppmvd at 15 percent O₂ (2.5 g/bhp-hr) as BACT for CO from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22).

The combination of permit limits and source test data in Appendix D for waste gas-fired reciprocating IC engines indicate CO levels of 250 ppmvd (at 15 percent O₂) or less are achievable. Given that the majority of California is nonattainment for the ozone ambient air quality standards but attainment for the CO ambient air quality standards, ARB staff has identified the most stringent CO limit as 250 ppmvd at 15 percent O₂ from biogas-fired reciprocating IC engines. Regulatory agencies should evaluate the lower CO limits identified for individual projects that trigger BACT for CO.

iii. Control of VOC Emissions

Landfill Gas

The most stringent VOC limit for an operational landfill gas-fired reciprocating IC engine is 0.1 g/bhp-hr (approximately 20 ppmvd at 15 percent O₂). This VOC limit is required in the permits for Reference 6 in Table D-22, which consist of five identical 4,230 bhp landfill gas-fired engines. Two of the engines failed VOC source tests on two occasions. However, ARB staff found eight source tests at this facility demonstrating

compliance with the VOC limit (References 10, 13, 14, 15, 16, 17, 18, and 19 in Table D-22). In addition, source tests at two other facilities demonstrated compliance with 20 ppmvd at 15 percent O₂ (References 5 and 25 in Table D-22).

The next most stringent VOC limit is 28 ppmvd at 15 percent O₂ and is required in the permit for Reference 26 in Table D-22. SCAQMD Rule 1110.2 requires 30 ppmvd at 15 percent O₂, for landfill gas-fired reciprocating IC engines effective July 1, 2012 (Reference 1 in Table D-22). The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O₂ (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22).

Sewage Digester Gas

The most stringent VOC limit for a sewage digester gas-fired reciprocating IC engine is 28 ppmvd at 15 percent O₂ (approximately 0.13 g/bhp-hr). This VOC limit is required in the permit for Reference 3 in Table D-23 for a 396 bhp sewage digester gas-fired engine. ARB staff found three source tests demonstrating compliance with the VOC limit (References 5, 6, and 8 in Table D-23).

SCAQMD Rule 1110.2 requires 30 ppmvd at 15 percent O₂, for digester gas-fired reciprocating IC engines effective July 1, 2012 (Reference 1 in Table D-23). The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O₂ (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 2 in Table D-23).

Manure Digester and Co-Digester Gas

The most stringent VOC limit for a co-digester gas-fired reciprocating IC engine (dairy manure and cheese waste) is 20 ppmvd at 15 percent O₂. This VOC limit is required in the permit for Reference 7 in Table D-24. A recent source test confirmed compliance with this limit (Reference 8 in Table D-24).

The most stringent VOC limit for a dairy manure digester gas-fired reciprocating IC engine is 0.13 g/bhp-hr (approximately 28 ppmvd at 15 percent O₂). This VOC limit is required in the permit for Reference 2 in Table D-24.

The next most stringent VOC limit of 30 ppmvd at 15 percent O₂ is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-24), for digester gas-fired reciprocating IC engines. The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O₂ (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 3 in Table D-24).

The combination of permit limits and source test data for waste gas-fired reciprocating IC engines indicate VOC levels of 20 ppmvd (at 15 percent O₂) or less are achievable. Therefore, ARB staff has identified the most stringent VOC limit as 20 ppmvd at 15 percent O₂ for biogas-fired reciprocating IC engines.

iv. Control of PM10 Emissions

The PM10 data that ARB staff was able to gather for landfill and digester gas-fired reciprocating IC engines for this Report was very limited. Staff did not locate a BACT determination for PM10 from landfill or digester gas-fired reciprocating IC engines. PM10 permit limits ranged from 0.036 to 0.1 g/bhp-hr (see Tables D-22, D-23, and D-24). Available source tests indicate compliance with 0.1 g/bhp-hr but were in excess of 0.036 g/bhp-hr.

Therefore, ARB staff has identified the most stringent PM10 limit as 0.1 g/bhp-hr or less from biogas-fired reciprocating IC engines.

v. Control of SOx Emissions

The data set available for this Report to establish a SOx limit for landfill and digester gas reciprocating IC engines was fairly limited and variable. As expected, SOx emission limits were tied to fuel sulfur content. Some permits specified use of control systems for removal of H₂S from the waste gas in conjunction with maximum fuel sulfur content limits.

Therefore, ARB staff has identified the most stringent SOx limit as the emission level corresponding to use of a fuel gas pretreatment system for sulfur removal and a maximum fuel sulfur content limit for biogas-fired reciprocating IC engines.

b. Turbines

This section is not intended to apply to limited use turbines (e.g., operating hours limited to less than 877 hours per year, and in some cases, less than 200 hours per year). District rules and BACT clearinghouses should be consulted for guidance on alternative emission limits allowed for limited use turbines. Some information is included in Appendix D.

i. Control of NOx Emissions

For the data set collected by ARB staff for this Report, the most stringent permitted NOx limit for landfill or digester gas-fired turbines is 25 ppmvd at 15 percent O₂. This limit was recommended as BACT in ARB's 2002 DG BACT Guidance (Reference 5 in Table D-26), and is also referenced as BACT in the SCAQMD and BAAQMD clearinghouses (References 4 and 11 in Table D-26). This NOx limit is required in the permits for References 6 and 7 in Table D-26. This limit is based on turbines fueled by sewage digester or landfill gas and utilize one or more control methods for NOx including water or steam injection and low-NOx combustors.

The most stringent district rule requirement for new and existing gaseous-fueled turbines is contained in SJVAPCD Rule 4703 (References 1 and 2 in Table D-26).

While compliance dates for some facilities will extend to 2012, NO_x is limited to 5 ppmvd (at 15 percent O₂) for units rated from 3 to 10 MW²⁶ and 9 ppmvd (at 15 percent O₂) for units rated less than 3 MW. The District's rule does not distinguish between types of gaseous fuel²⁷, with the expectation that any issues associated with turbine wear and emission control catalyst deactivation from contaminants present in waste gases can be mitigated by appropriate gas pretreatment systems.

In consideration of the SJVAPCD standards, ARB staff has identified the most stringent NO_x limits as 9 ppmvd (at 15 percent O₂) for biogas-fired turbines rated less than 3 MW and 5 ppmvd (at 15 percent O₂) for biogas-fired turbines rated at 3 MW and larger.

ii. Control of CO Emissions

The most stringent CO limit for a landfill or digester gas-fired turbine is 60 ppmvd at 15 percent O₂. This limit was required as BACT for CO in the permit for Reference 10 in Table D-26.

The next most stringent CO limit for a landfill or digester gas-fired turbine is 130 ppmvd at 15 percent O₂. This limit is referenced as BACT in the SCAQMD Guidelines for Non-Major Facilities (Reference 11 in Table D-26). This CO limit is also required in the permits for References 6 and 7 in Table D-26. The emission control technology is not specified in the permit information received by ARB staff.

Source test data for landfill gas-fired turbines at two sites resulted in average CO emissions of 30 to 32 ppmvd at 15 percent O₂ (References 8 and 9 in Table D-26). Therefore, ARB staff has identified the most stringent CO limit as 60 ppmvd at 15 percent O₂ for biogas-fired turbines.

iii. Control of VOC Emissions

ARB staff received a limited data set on achievable VOC emission levels for landfill and digester gas-fired turbines. ARB staff found no specific BACT determinations for VOC from landfill or digester gas turbines. VOC limits from two permits received by ARB staff ranged from 3.5 to 20 ppmvd at 15 percent O₂. Two source tests received by ARB staff measured VOC emissions from 2 to 3.5 ppmvd at 15 percent O₂.

Based on this information, ARB staff has identified the most stringent VOC limit as 3.5 ppmvd at 15 percent O₂ for biogas-fired turbines. However, due to uncertainties about consistent emissions performance, ARB staff recommends that regulatory agencies consult with the turbine manufacturer on guaranteed VOC emission levels as well as evaluate additional source test results to assess the appropriate VOC limit for biogas-fired turbines.

²⁶ A slightly higher NO_x limit is allowed for turbines that are restricted in their operating hours as an enforceable limit in their permit.

²⁷ Rule 4703 defines gas fuel as any of the following fuels or fuels containing any of the following fuels: natural gas, LPG, propane, digester gas, and landfill gas.

iv. Control of PM10 Emissions

ARB staff received insufficient data on achievable PM10 emission levels for landfill and digester gas-fired turbines to recommend a specific PM10 emission limit at this time. However, SCAQMD and BAAQMD BACT guidelines specify fuel gas pretreatment for particulate removal as BACT for PM10 for landfill and digester gas-fired turbines.

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of a fuel gas pretreatment system for particulate removal for biogas-fired turbines.

v. Control of SOx Emissions

Like other fuels, fuel sulfur is the source of SOx emissions from turbines fired on landfill and digester gas. Since SOx emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. However, an applicant has limited control over the incoming waste stream to landfills and wastewater treatment plants. Therefore, ARB staff recommends establishing a SOx limit based on setting a limit on the maximum sulfur content of the fuel. This is consistent with BAAQMD BACT Guideline 89.3.1 for landfill gas-fired turbines (Reference 4 in Table D-26) and SCAQMD Guidelines for Non-Major Facilities (Reference 11 in Table D-26).

Therefore, ARB staff has identified the most stringent SOx limit as the emission level corresponding to use of landfill gas with a sulfur content of no more than 150 ppmv as H₂S and sewage digester gas with a sulfur content of no more than 40 ppmv as H₂S for biogas-fired turbines.

U. Other Operations and Equipment

1. Thermal Conversion Technology, Non-Incineration

The call for information for the Report included biomass conversion using “non-incineration” thermal conversion technologies such as pyrolysis and gasification. In this category of process equipment, ARB staff received one permit for an experimental research demonstration pyrolysis system in the SCAQMD that used sorted municipal solid waste and sewage sludge as feedstock. The permitted pyrolysis system consisted of the following equipment:

Non-hazardous feedstocks pyrolysis system

- Feed hopper;
- Screw conveyor, feed, enclosed, 5 hp;
- Two 16-inch entry air lock knife valves, closed loop, hydraulically driven, 90 ft³ per hour maximum feed rate;

- Pyrolytic thermal converter, indirectly heated with four low NO_x burners, natural gas fired, 1.5 MMBtu/hr each, with a combustion air blower, 15 hp, and a hydraulically driven variable speed helical screw;
- Two 12-inch Dezuric exit air lock knife valves, hydraulically driven, with steam induction chamber;
- Carbon char discharge system, consisting of enclosed gravity bucket, and screw conveyors; and
- Carbon char storage bins.

Air pollution control system venting a pyrolytic converter

- High temperature multiclone, boiler, and steam systems;
- Thermal oxidizer with a natural gas fired low NO_x burner rated at 5 MMBtu/hr, two combustion air blowers, 7.5 hp each, equipped with a NO_x control SNCR with a urea injection system;
- Two primary waste heat boilers, unfired, fire tube type, 300 hp total;
- Activated carbon injection system, consisting of a screw conveyor, carbon injection port, and 3.5-inch injection tube;
- Baghouse and a pulse jet cleaning system;
- Wet scrubber; and
- Exhaust stack with a 40 hp exhaust blower, 22,000 cfm, in-stack mounted carbon filter.

The system, however, is no longer operating and no longer has a valid air permit. The permit limited the operating hours as well as emissions to just below the levels that would trigger federal requirements for small municipal solid waste combustors. According to District staff, is it likely that more efficient air pollution control would have been required if the company requested either more operating time and/or higher throughput.

Therefore, ARB staff does not have sufficient information to identify the most stringent emission levels for a commercial-scale pyrolysis system using biomass feedstocks for transportation fuels at this time. ARB staff will include non-incineration thermal conversion technologies in future report updates.

2. Biomass Syngas-Fueled Reciprocating IC Engine

ARB staff did not locate any biorefineries in the State that produce transportation fuels from biomass-derived synthesis gas (i.e., syngas). However, staff did find a gasification system at Parreira Almond Processing Company in Los Banos, California, that converts orchard trimmings into syngas that is used in a generator to produce electricity. The California Integrated Waste Management Board provided a low-interest loan to Ortigalita Power Company to help fund the purchase and installation of the gasification equipment at Parreira Almond. The project received an ATC from the SJVAPCD. Information from the BACT analysis for the project is included for informational purposes, since staff expects that this equipment could be used at a biorefinery in the future.

a. Control of NO_x Emissions

The most stringent NO_x limit for a biomass syngas-fueled reciprocating IC engine is 5 ppmvd at 15 percent O₂. This NO_x limit is listed as technologically feasible BACT in SJVAPCD Guideline 3.3.14 (Reference 2 in Table D-25). The next most stringent NO_x limit is 9 ppmvd at 15 percent O₂. This NO_x limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 3.3.14 (Reference 1 in Table D-25).

Therefore, ARB staff has identified the most stringent NO_x limit as 5 ppmvd at 15 percent O₂ for syngas-fueled reciprocating IC engines.

b. Control of VOC Emissions

The most stringent VOC limit for a biomass syngas-fueled reciprocating IC engine is 25 ppmvd at 15 percent O₂. This VOC limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 3.3.14 (Reference 1 in Table D-25).

Therefore, ARB staff has identified the most stringent VOC limit as 25 ppmvd at 15 percent O₂ for syngas-fueled reciprocating IC engines.

3. Composting

While composting operations are not directly related to biofuel production processes, ARB staff anticipates that composting may be conducted at biorefineries to manage waste feedstocks.

a. Control of VOC and NH₃ Emissions

Sample permits received by ARB staff included facilities that conduct composting operations both outside and within the confines of an enclosed building. For processes within an enclosure, the most stringent VOC and ammonia (NH₃) limits require 80 percent control efficiency by weight. This is typically achieved by venting VOC and NH₃ emissions generated within the enclosure (i.e., the building and/or in-vessel compost container) to a biofilter. This is required in SCAQMD Rule 1133.2 and in the

permits for References 1, 4, 5, and 6 in Table D-27). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a control system (enclosure with biofilter or equivalent technology) capable of 80 percent or better control efficiency, and a NH₃ limit corresponding to the use of a control system capable of 80 percent or better control efficiency.

b. Control of PM10 Emissions

Permits for composting facilities require the use of water trucks, sprays, or sprinklers to limit PM10 emissions generated from transfer points, stockpiles, and handling operations. The most stringent PM10 mitigation technique is a dust collection system consisting of a cartridge filter baghouse located within a building in the screening area (see Reference 4 in Table D-27). Typical PM10 control efficiency for a baghouse is 99 percent or more.

Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of a PM10 control system (enclosure with baghouse or equivalent technology) capable of 99 percent or better control efficiency.

4. Diesel-Fueled Emergency Engine Generator

Diesel-fueled engine generator sets are used by almost all types of businesses for emergency power supply if the power grid fails and can be expected to be included at biorefineries. In California, most air districts require a permit for stationary diesel-fueled emergency engine generators rated at 50 bhp.

a. Control of NOx, CO, VOC, and PM10 Emissions

In general, the most stringent NOx, CO, VOC, and PM10 limits for a diesel-fueled emergency engine generator are the emission limits corresponding to the latest U.S. EPA Tier certification levels for off-road compression ignition engines for the applicable bhp range. These emission limits are required statewide via the ARB's ATCM for Stationary Compression Ignition Engines, which was adopted by the Board in 2003 and first amended in 2006 (References 2 and 3 in Table D-28). Several districts have adopted the ATCM requirements into their own rule books and/or included them in their BACT clearinghouses (References 1, 4, and 5 in Table D-28). On October 21, 2010, the Board adopted amendments to the ATCM to more closely align the requirements in the ATCM with those in the federal Standards of Performance for Stationary Compression-Ignition Internal Combustion Engines (NSPS) that was promulgated on July 11, 2006, help clarify provisions in the ATCM, address new information, and remove provisions no longer needed. For new emergency standby engines, the regulation retains the 0.15 g/bhp-hr PM emissions limit in the ATCM for all horsepower categories. With one exception, this amendment results in the emissions requirements for emergency standby engines being the same in the ATCM as those in the NSPS. The only exception is for engines less than 175 hp. For these engines, the NSPS establishes a PM emissions limit of 0.22 to 0.30 g/bhp-hr depending on the horsepower,

while the ATCM retains a more stringent 0.15 g/bhp-hr PM emissions standard. ARB staff believes this emissions limit represents best available control technology for this application and many engines less than 175 hp are available that can meet the 0.15 g/bhp-hr PM. ARB staff maintains a website that posts listings of the engines by horsepower and model year that are less than 175 hp and meet the ATCM PM standard for new emergency standby engines (see <http://www.arb.ca.gov/diesel/ag/agengtables.htm>). The other pollutant emission standards are the same as the NSPS requirements. This amendment eliminated the existing requirement in the ATCM that would have required new emergency standby engines to meet the after-treatment based Tier 4 standards when they are more stringent than 0.15 g/bhp-hr. It also prevents the installation of any new emergency standby engine that does not meet the 2007 model year or newer emissions limits in the Off-Road Standards (title 13, CCR, section 2423) for all pollutants.

Table D-29 in Appendix D provides a summary of the newly-amended emission standards for new emergency standby engines, which became effective on May 19, 2011.

Therefore, ARB staff has identified the most stringent NO_x, CO, VOC, and PM₁₀ limits for a diesel-fueled emergency engine generator rated at 50 bhp and greater as the emission limits corresponding to the ARB's ATCM for Stationary Compression Ignition Engines (adopted October 21, 2010). For engines less than 50 bhp, the reader should refer to the latest U.S. EPA Tier certification levels for off-road compression ignition engines, for the applicable bhp range.

b. Control of SO_x Emissions

The most stringent SO_x limit for a diesel-fueled emergency engine generator is an emission limit corresponding to use of CARB diesel (15 ppmw sulfur or less). Use of CARB diesel is required by the statewide ATCM for Stationary Compression Ignition Engines (References 2 and 3 in Table D-28). CARB diesel is also listed as meeting BACT for SO_x for diesel-fueled emergency IC engines in the SJVAPCD, SCAQMD, and BAAQMD (References 1, 4, and 5 in Table D-28).

Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of CARB diesel for diesel-fueled emergency engine generators.

V. GHG Emission Reduction Measures

GHGs are being evaluated in other existing ARB activities associated with AB 32, and therefore, unit-level GHG emission standard recommendations are not covered in this Report. However, the mitigation strategies recommended in this Report will not only provide further reductions in criteria pollutants, but also reduce GHGs. These strategies achieve GHG reductions by promoting overall efficiency in energy conversion technologies and encouraging the recovery of energy and other marketable products from biomass feedstocks. Implementation of the mitigation strategies will allow users of

electricity, heat, and liquid and gaseous fuels to partially offset their reliance upon fossil fuels, reduce GHGs, and preserve efforts to achieve and maintain federal and state ambient air quality standards and to reduce TAC emissions. ARB staff expects that the mitigation strategies recommended in this Report will serve as a starting place for considering strategies and measures to reduce GHGs from biorefineries.

State-Level Activity

AB 32 directs California to reduce its GHG emissions to 1990 levels by 2020. ARB is designated as the lead agency for implementation, and is working with the California Environmental Protection Agency to coordinate the statewide effort to achieve real, quantifiable, and cost-effective reductions in GHG emissions.

The AB 32 Scoping Plan²⁸ adopted on December 12, 2008, contains the main strategies California will use to reduce GHG emissions to meet the 2020 limit. The Scoping Plan has a range of GHG reduction actions which include direct regulations, alternative compliance mechanisms, monetary and non-monetary incentives, voluntary actions, and market-based mechanisms such as a cap-and-trade system, and an AB 32 program implementation regulation to fund the program. These activities cover specific industry sectors: agriculture, electricity, forestry, high global warming potential, land use and local initiatives, manufacturing, and waste management/recycling.

On October 20, 2011, the Board adopted the final cap-and-trade regulation, the major building block of ARB's climate plan. The regulation sets a statewide limit on sources responsible for 85 percent of California's GHG emissions and establishes a price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy. The program is designed to provide covered entities the flexibility to seek out and implement the lowest-cost options to reduce emissions. The regulation will cover 360 businesses representing 600 facilities and is divided into two phases: the first, beginning in 2013, will include all major industrial sources along with electricity utilities; the second, starting in 2015, brings in distributors of transportation fuels, natural gas and other fuels. Companies are not given a specific limit on their GHG emissions but must supply a sufficient number of allowances (each the equivalent of one ton of carbon dioxide) to cover their annual emissions. As the cap declines each year, the total

²⁸ As a result of litigation, a California Superior Court found that the analysis of the alternatives identified in the 2008 Scoping Plan's Functional Equivalent Document failed to sufficiently analyze alternatives to the cap-and-trade program component and ordered ARB to take no action in reliance on the Scoping Plan until it complied with CEQA. ARB appealed the decision; however, to remove any doubt, ARB staff revisited the Scoping Plan alternatives and produced a supplemental analysis of project alternatives that was released on June 13, 2011. The California Court of Appeal has not yet decided the substantive portion of the case, but on June 24, 2011, it granted ARB a temporary stay of the Superior Court's ruling and allowed ARB to continue to advance and finalize plans for the cap-and-trade program while the Court of Appeal determined the merits of ARB's appeal. In August 2011, the Scoping Plan and supplemental analysis were brought back to the Board for reconsideration and ultimately re-approved. The litigants appealed the Court of Appeal's decision to the California Supreme Court. On September 28, 2011, the Supreme Court sided with the Court of Appeal and declined to immediately halt implementation of the cap-and-trade program. The Supreme Court's decision was limited only to the stay application instituted by the Court of Appeal. The Court of Appeal will continue to hear ARB's appeal on the merits of the Superior Court's final order.

number of allowances issued in the State drops, requiring companies to find the most cost-effective and efficient approaches to reducing their emissions. The first compliance year when covered sources will have to turn in allowances is 2013. The Board-adopted regulation, as well as other details on the cap-and-trade program, is available at: <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>.

In addition to the cap-and-trade program, ARB has adopted several measures in accordance with the Scoping Plan. These measures include the LCFS, heavy-duty vehicle GHG emission reduction regulation, tire inflation regulation, landfill methane control measure, semiconductor perfluorocarbon emissions reduction regulation, and the regulation to reduce sulfur hexafluoride emissions from non-electric and non-semiconductor applications. Information on all measures adopted to-date, activities currently under way, and planned activities can be accessed on the ARB's Climate Change webpage at: www.arb.ca.gov/cc/cc.htm.

Federal-Level Activity

As of January 2, 2011, GHG emissions from the largest stationary sources are, for the first time, covered by the federal PSD and Title V Operating Permit Programs. U.S. EPA issued a final rule on May 13, 2010, to address GHG emissions from stationary sources under these federal Clean Air Act permitting programs. The rule sets thresholds for GHG emissions that define when permits under the PSD and Title V operating permits programs are required for new, modified, or existing facilities. The Clean Air Act permitting program emission thresholds for criteria pollutants are 100 tons per year and 250 tons per year. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs, because GHGs are emitted at much higher volumes. The rule "tailors" the permit programs to limit which facilities will be required to obtain PSD and Title V permits. Without this tailoring rule, these lower Clean Air Act thresholds would have been effective automatically for GHGs on January 2, 2011.

The GHG tailoring rule requires PSD permitting of GHGs beginning January 2, 2011, if a source is already subject to PSD and GHGs are increased by 75,000 tons per year CO₂e. After July 1, 2011, PSD permits are required for new sources with GHG emissions at 100,000 tons per year CO₂e, or modifications at existing facilities that increase GHG emissions by at least 75,000 tons per year CO₂e regardless of whether or not they were already subject to PSD. New or modified facilities with GHG emissions that trigger PSD permitting requirements would need to apply for a revision to their operating permits to incorporate the best available control technologies and energy efficiency measures to minimize GHG emissions. These controls will be determined on a case-by-case basis during the PSD process. U.S. EPA has developed a website that provides guidance and tools for permitting of GHGs, which includes a *PSD and Title V Permitting Guidance for Greenhouse Gases*, GHG Control Measures White Papers, and a Greenhouse Gas Mitigation Strategies Database.²⁹ The permitting guidance does not establish a new approach for selecting BACT for GHGs. Rather, permitting authorities may continue to use the five-step, top-down BACT process already well-established for

²⁹ See U.S. EPA Clean Air Act Permitting for Greenhouse Gases website at: <http://www.epa.gov/nsr/ghgpermitting.html>.

criteria pollutants. In addition, the U.S. EPA's RACT/BACT/LAER Clearinghouse has been expanded to include GHG control and test data and a message board for permitting authorities.

Similar to the requirements for PSD permits, only sources currently subject to Title V would be subject to Title V requirements for GHG emissions as of January 2, 2011. However, after July 1, 2011, Title V operating permit requirements will apply to sources based on their GHG emissions even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tons per year CO₂e will be subject to Title V permitting requirements.

W. Toxic Air Contaminant Emissions

A health risk assessment (HRA) evaluates the potential for adverse health effects that can result from public exposure to emissions of toxic substances. The information provided in the HRA can be used to decide if or how a project should proceed. Some districts may have regulations, or established policies, on HRAs for making risk management decisions. Other districts have relied upon the authority provided in California Health and Safety Code Section 41700 to manage health risk impacts. When applicable policies or regulations are not in place, ARB staff recommends that health risk be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (http://www.oehha.org/air/hot_spots/HRAguidefinal.html).

Applicants for biorefinery projects have typically been required to submit risk assessments to satisfy CEQA review requirements. ARB staff's review of available HRAs prepared for recent proposed biorefinery projects in California report the increase in lifetime cancer risk is less than 10 in a million – a significance threshold for health risks used by many districts. This often includes the requirement to use the best available control technology for toxic emissions (T-BACT) on individual emission units where the calculated cancer risk exceeds 1 in a million.³⁰ It should be noted that for many of these projects, the majority of the calculated cancer risk values are the result of diesel PM emissions from trucks.³¹ As a result, ARB staff recommends 2007 or newer model year engines where heavy-duty diesel trucks are used to transport feedstocks or finished product, in order to mitigate emissions from mobile sources associated with biorefineries (see more detailed discussion in Chapter VI). Based on HRA results to-date and application of the appropriate mitigation measures, ARB staff does not anticipate that the health risk from an individual biorefinery project will be significant. However, staff will continue to monitor projects and address issues as they arise.

³⁰ Each air district determines its own levels of significance for cancer and non-cancer health effects for notification and risk reduction. District regulations and policies on health risk assessments can be accessed via individual district websites at: <http://www.arb.ca.gov/capcoa/roster.htm>.

³¹ Examples of onsite diesel PM emissions from trucks at a corn ethanol plant include, trucks traveling to/from and idling at the ethanol loading and denaturant unloading station, trucks traveling to/from and idling at the CO₂ loading station, and trucks traveling to/from and idling at the wet distiller grain loading station.

V. MOST STRINGENT EMISSION LIMITS FOR PROCESS EQUIPMENT AT BIOREFINERIES

Tables V-1, V-2, and V-3 summarize the most current stringent emission limits for process equipment that might be used at biorefineries. The alternate limits listed under certain equipment categories in Tables V-2 and V-3 were identified by ARB staff as being the most stringent emission limit for an individual air pollutant contained in a rule or regulation, guidance document, BACT analysis, or permit. In the case of biogas-fueled fuel cells, the alternate limits are the future emission standards that will be required by statewide regulation as of January 1, 2013. Data collected by ARB staff indicates the 2013 standards may be achievable now, and therefore, ARB staff recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project. For the other equipment categories, ARB staff did not have sufficient data at the drafting of this Report to determine that the alternate limit is achievable in conjunction with the other corresponding most stringent emission limits identified for the class/category of source. In these cases, ARB staff also recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project.

While the current top-down BACT process specifies that the appropriate BACT emission level is determined on a per pollutant basis and requires selecting the most stringent emission level of a set of minimum requirements (see Appendix F, Description of a Generalized Procedure for Determining BACT), ARB staff is aware of issues associated with “cherry picking” the best emission limits from different data sets. This approach, if not done correctly, can result in the crafting of an air permit with emission limits that cannot be simultaneously met for all pollutants on a consistent basis. In identifying the most stringent emission levels in the following tables, ARB staff did consider these issues, such as the inverse relationship between NO_x and CO for combustion sources and technical factors unique to variations in design, pollution controls, and fuels that can affect achievable emission levels.

The emission limits contained in the following tables apply to normal operations and should not be construed as being achievable during startup, shutdown, or malfunction conditions.

The recommendations in this Report are current as of publication. However, ARB staff will continue to evaluate new emissions data and periodically provide updates to this Report using the process described in Chapter VII.

Table V-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources

Class/Category of Source	NO _x	CO	VOC	SO _x	PM ₁₀
Methanol / Sodium Methoxide receiving and storage			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Fermentation process: yeast, liquefaction, beerwell, and process condensate tanks			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Distillation and wet cake processes			Emission limit corresponding to use of a VOC control system (wet scrubber or equivalent) capable of 95% or better control efficiency		
Pumps and compressor seals			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Valves, flanges, and other types of connectors			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Storage tank (fixed roof)			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		

Table V-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Evaporative Loss Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Storage tank (floating roof)			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel loading operations			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel transfer and dispensing operations			Emission limit corresponding to use of an ARB certified Phase I vapor recovery system		

Table V-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Natural gas-fired boiler, ≥ 2 to < 5 MMBtu/hr	Non-atmospheric units: 9 ppmvd @ 3% O ₂ (0.011 lb/MMBtu) Atmospheric units: 12 ppmvd @ 3% O ₂ (0.015 lb/MMBtu)	Firetube type: 50 ppmvd @ 3% O ₂ Watertube type: 100 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥ 5 to < 20 MMBtu/hr	6 ppmvd @ 3% O ₂ (0.007 lb/MMBtu)	Firetube type: ≤ 50 ppmvd @ 3% O ₂ Watertube type: ≤ 100 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf

Table V-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources (continued)

Class/Category of Source	NO _x	CO	VOC	SO _x	PM ₁₀
Natural gas-fired boiler, ≥20 MMBtu/hr	5 ppmvd @ 3% O ₂ (0.0062 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O ₂ Watertube type: ≤100 ppmvd @ 3% O ₂ For units ≥250 MMBtu/hr ³² : 10 ppmvd @ 3% O ₂	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired dryer	0.018 lb/MMBtu (15 ppmv @ 3% O ₂)	0.07 lb/MMBtu	Emission limit corresponding to use of a VOC capture and control with thermal or catalytic incineration (98% control) or equivalent	Emission limit corresponding to use of a wet scrubber (95% control)	Emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series (98.5% control) or equivalent
Flare (ethanol production)	0.05 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu
Biomass-fired boiler	0.012 lb/MMBtu (9 ppmvd @ 3% O ₂)	0.046 lb/MMBtu (59 ppmvd @ 3% O ₂) Alternate Limit: 0.01 lb/MMBtu (22 ppmvd @ 3% O ₂)	0.005 lb/MMBtu (11 ppmvd @ 3% O ₂)	0.012 lb/MMBtu (7 ppmvd @ 3% O ₂)	0.024 lb/MMBtu (0.01 gr/scf @ 12% CO ₂)
Landfill gas-fired flare	0.025 lb/MMBtu	0.06 lb/MMBtu	Emission limit corresponding to 98% VOC destruction efficiency or 20 ppmv @ 3% O ₂	Emission limit corresponding to use of a wet scrubber with 98% control efficiency	Emission limit corresponding to use of steam injection and/or knockout vessel

³² This CO limit may be required for boilers rated at <250 MMBtu/hr if an oxidation catalyst is found to be cost effective, is necessary to meet toxic best available control technology, or for VOC emission control.

Table V-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Manure digester and co-digester gas-fired flare	0.03 lb/MMBtu (25 ppmvd @ 3% O ₂)	Operate per manufacturer specifications to minimize CO	0.03 lb/MMBtu	Emission limit corresponding to use of a H ₂ S removal system (dry or wet scrubber or equivalent)	Emission limit corresponding to use of smokeless combustion and LPG or natural gas-fired pilot
Biogas-fired microturbine	0.5 lb/MWh As of 1/1/2013: 0.07 lb/MWh	6.0 lb/MWh As of 1/1/2013: 0.10 lb/MWh	1.0 lb/MWh As of 1/1/2013: 0.02 lb/MWh	N/A	N/A
Biogas-fired reciprocating internal combustion engine	11 ppmvd @ 15% O ₂ (or 0.15 g/bhp-hr) in conjunction with an effective and efficient biogas treatment system Alternate Limit for dairy digester gas-fired rich-burn engines: 9 ppmvd @ 15% O ₂ (or 0.15 g/bhp-hr)	250 ppmvd @ 15% O ₂	20 ppmvd @ 15% O ₂	Emission limit corresponding to use of a fuel gas pretreatment system for sulfur removal along with maximum fuel sulfur content limit	0.1 g/bhp-hr
Biogas-fired turbine, <3 MW	9 ppmvd @ 15% O ₂	60 ppmvd @ 15% O ₂	3.5 ppmvd @ 15% O ₂ ³³	Landfill gas: Emission limit corresponding to use of landfill gas with sulfur content of no more than 150 ppmv as H ₂ S	Emission limit corresponding to use of a fuel gas pretreatment system for particulate removal
Biogas-fired turbine, ≥3 MW	5 ppmvd @ 15% O ₂			Digester gas: Emission limit corresponding to use of digester gas with sulfur content of no more than 40 ppmv as H ₂ S	

³³ Due to limited data set available for this Report on achievable VOC emission levels for landfill and digester gas-fired turbines, ARB staff recommends that regulatory agencies consult with the manufacturers on guaranteed emission levels, as well as, evaluate additional source tests to determine the appropriate VOC limit for a turbine.

Table V-2. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Combustion Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Biomass syngas-fueled ³⁴ reciprocating internal combustion engine	5 ppmvd @ 15% O ₂	N/A	25 ppmvd @ 15% O ₂	N/A	N/A
Diesel-fueled emergency engine generator	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range ³⁵	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range	Emission limit corresponding to use of CARB, or very low sulfur, diesel fuel (15 ppm sulfur by weight)	Engine meeting emission standards of ARB's Airborne Toxic Control Measure for Stationary Compression Ignition Engines for applicable horsepower range

Table V-3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Miscellaneous Sources

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Grain receiving, conveying, and grinding operations					Emission limit corresponding to use of a baghouse with 99% control, or equivalent
Wet cooling tower					Emission limit corresponding to use of a drift eliminator with 0.0005% drift loss
Compressed gas dispensing operations	No emissions – use of closed loop system with all vent and excess process gas directed to an on site treatment system, used in vehicles, or directed to another combustion or processing facility that can process the biogas and which has been issued a valid air permit				

³⁴ BACT guideline that is the basis of these emission limits defines syngas, or synthetic gas, to be “derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (<5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide.”

³⁵ Refer to ARB regulations and/or Appendix D Table D-29 of this Report for the applicable emission standard.

Table V-3. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries – Miscellaneous Sources (continued)

Class/Category of Source	NOx	CO	VOC	SOx	PM10
Biogas-fueled fuel cell ³⁶	0.5 lb/MWh Alternate Limit: 0.07 lb/MWh	6.0 lb/MWh Alternate Limit: 0.10 lb/MWh	1.0 lb/MWh Alternate Limit: 0.02 lb/MWh	N/A	N/A
Composting			Emission limit corresponding to use of a VOC control system (enclosure with biofilter or equivalent) capable of 80% or better control efficiency Ammonia: Emission limit corresponding to use of an NH3 control system capable of 80% or better control efficiency		Emission limit corresponding to use of a PM10 control system capable of 99% or better control efficiency

³⁶ Emission limits are the 2008 standards for waste gas required by the ARB's Distribution Generation (DG) Certification Regulation. Alternate limits represent the 2013 standards for waste gas required by the DG Certification Regulation.

This Page Left Intentionally Blank

VI. MOBILE SOURCE EMISSIONS ASSOCIATED WITH BIOREFINERIES

This chapter provides an overview of vehicle and mobile equipment associated with new and expanding biorefineries and summarizes the ARB-adopted statewide mobile source regulations aimed at reducing the emissions from this equipment. The chapter also identifies mitigation measures that can achieve emission reductions beyond those required by ARB's mobile source regulations, as well as strategies to reduce both fugitive PM and impacts to sensitive receptors associated with mobile source activities at and around biorefineries.

The LCFS Initial Statement of Reasons identified additional truck trips as the major source of criteria pollutant impacts from the production (after mitigation and offsets), transportation, and distribution of biofuels. ARB's overall regulatory strategy to reduce emissions from mobile sources revolves around requiring newer vehicles and equipment as they become available. For example, several ARB regulations already require the use of 2007 trucks (i.e., trucks equipped with engines that meet the 2007 emission standards for heavy-duty diesel vehicles) that are equipped with catalyzed diesel particulate filters that reduce diesel PM and near-source impacts. Additional requirements in these regulations phase-in trucks with engines that meet the 2010 emission standards as they become more main stream, because they have the added benefit of NOx emission control for ozone nonattainment areas.

A. Motor Vehicle and Mobile Equipment Used In Biorefinery Operations

On-road vehicles, off-road vehicles, and portable equipment are used for a variety of activities at a biorefinery including: construction and maintenance of the facility, delivery of raw product, processing of raw material and finished fuel product, and delivery of finished fuel product. Mobile sources emit criteria pollutants, TACs, and GHGs.

1. On-Road Vehicles

On-road diesel vehicles are a source of CO, diesel PM, HC, and NOx emissions. This category of mobile sources includes light-duty vehicles, light-duty trucks, and heavy-duty vehicles used for on-road transportation. The following is a partial listing of the types of on-road vehicles that may be used for the delivery and processing of raw material and finished fuel product at biorefineries:

- solid waste collection vehicles,
- dump trucks,
- feedstock/ raw product delivery trucks, and
- fuel delivery trucks.

2. Off-Road Vehicles

Off-road diesel vehicles are a source of CO, diesel PM, HC, and NO_x emissions. Off-road vehicles may be used during the various stages of construction and maintenance of biorefineries including demolition, clearing, dewatering, excavation, grading, paving, surfacing, foundation work, building erection and other infrastructure developments. The following is a partial listing of the types of off-road vehicles that may be used for the construction and maintenance of biorefineries:

- loaders,
- excavators,
- dozers,
- drill rigs, and
- forklifts.

3. Portable Engines and Equipment

Portable engines and equipment are a source of CO, diesel PM, HC, NO_x, and fugitive emissions of PM. Portable engines are used for a variety of applications, including pumps, cranes, oil well drilling, power generators, dredging equipment, rock crushing and screening equipment, welding equipment, wood chippers, and compressors. The following is a partial listing of the types of portable equipment that may be used for the construction and maintenance; and processing of raw material at biorefineries:

- compressors,
- generators,
- pumps,
- cranes,
- pile drivers,
- welders, and
- chippers and grinders.

B. ARB Mobile Source Regulations

As first described in Chapter 1, the ARB is responsible for developing statewide programs and strategies to reduce the emission of smog-forming pollutants and toxics from mobile sources. This section is intended to provide an overview of the major requirements of ARB regulations that apply to vehicles and mobile equipment used at biorefineries. The approved regulatory language and program Internet website addresses provided in this section should be consulted to verify the most current requirements of these regulations.

1. On-Road Vehicles

a. Emission Standards for New Heavy-Duty Truck Engines

This section discusses the emission standards that apply to new diesel engines used in heavy-duty highway vehicles. California is the only state that has the authority to establish new mobile source emission standards and/or test procedures that differ from federal standards and test procedures. California emission standards and test procedures must be, in the aggregate, at least as protective of public health and welfare as applicable federal standards and test procedures.

The U.S. EPA adopted emission standards for model year 2007 and later heavy-duty highway engines in January 2001, and the ARB adopted virtually identical standards in October 2001 (section 1956.8, title 13, California Code of Regulations and the incorporated "California Exhaust Emission Standards and Test Procedures for 1985 and Subsequent Model Heavy-Duty Diesel Engines and Vehicles"). ARB adopted the emission standards and test procedures beginning in the 2007 model year, the same year that these standards and test procedures apply federally. The emission standards apply to heavy-duty diesel engines (HDDE) and are optional for medium-duty diesel engines (MDDE). HDDEs are used in vehicles with a gross vehicle weight rating (GVWR) of 14,001 pounds and greater. MDDEs are used in vehicles with a GVWR of 8,501 to 14,000 pounds.

The emission standards in the regulation for model year 2007 and subsequent heavy-duty engines are shown in Table VII-1. MDDEs have the flexibility to certify their engines to optional super-ultra-low-emission-vehicle (SULEV) standards that are equivalent to one half of the PM and CO ultra-low-emission-vehicle (ULEV) emission standards.

Table VI-1. Summary of Heavy-Duty Diesel Cycle and Medium-Duty Diesel Engine Emission Standards (g/bhp-hr)

ARB Weight Class		Pollutant			
		NOx	NMHC	PM	CO
Heavy-Duty		0.2	0.14	0.01	15.5
Medium-Duty	ULEV	0.2	0.14	0.01	15.5
	SULEV	0.17	0.12	0.005	7.7

For HDDEs, the PM emission standard took full effect in the 2007 model year. The NOx and NMHC emission standards were phased-in for diesel engines between 2007 and 2010. The phase-in is on a percent-of-sales basis: 50 percent from 2007 through 2009 model years, and 100 percent in 2010 and subsequent model years. For MDDEs, the PM and CO emission standards took full effect in the 2007 model year. The NOx and NMHC emission standards were phased-in for diesel engines between 2007 and 2010. The phase-in is on a percent-of-sales basis: 50 percent from 2007 through 2009 model

years, and 100 percent in 2010 and subsequent model years. Table VII-2 below summarizes the phase-in schedule.

Table VI-2. Summary of Phase-In Schedule

Pollutant	Model Year			
	2007	2008	2009	2010+
NOx	50%	50%	50%	100%
NMHC				
PM	100%	100%	100%	100%
CO	100%	100%	100%	100%

b. On-Road Heavy-Duty Vehicle In-Use Regulation

ARB's On-Road Heavy-Duty Vehicle In-Use Regulation (or Truck and Bus Regulation), first approved by the Board on December 12, 2008, and subsequently amended on December 16, 2010, reduces PM and NOx emissions from existing diesel vehicles operating in California. The regulation applies to nearly all diesel-fueled trucks and buses with a GVWR greater than 14,000 pounds that are privately or federally owned and for privately and publicly owned school buses. Other public fleets, solid waste collection trucks, and transit buses are already subject to other regulations and are not part of the truck and bus regulation. Trucks that transport marine containers must comply with the ARB's drayage truck regulation. The 2010 amendments to the regulation are not yet effective. The Final Rulemaking Package for the Truck and Bus Regulation was filed with the Office of Administrative Law (OAL) on October 28, 2011. OAL has until December 14, 2011, to make a determination. If OAL determines that the rulemaking satisfies the Administrative Procedure Act, then OAL files the regulation with the Secretary of State and the regulation usually becomes effective within 30 days.

Requirements for Lighter Trucks and Buses

Lighter trucks and buses with a GVWR of 14,001 to 26,000 pounds do not have compliance requirements until 2015. Starting in 2015, these trucks and buses must have engines that are 2010 model year emission equivalent pursuant to the schedule in Table VII-3. Each year the fleet must meet the requirements of all prior years shown in the schedule. A 2007 model year emissions equivalent engine complies with the BACT requirements until January 1, 2023. Fleets also have the option to install a PM filter retrofit on a lighter truck by 2014 to make the truck exempt from replacement until January 1, 2020, and any lighter truck equipped with a PM filter retrofit prior to July 2011 will receive credit toward the compliance requirements for heavier trucks and buses in the same fleet.

Table VI-3. Compliance Schedule for Vehicles with GVWR 26,000 Pounds or Less

Compliance Date as of January 1	Existing Engine Model Year	BACT Requirements
2015	1995 and older	2010 model year emission equivalent
2016	1996	
2017	1997	
2018	1998	
2019	1999	
2020	2003 and older	
2021	2004-2006	
2023	2007-2009	

Requirements for Heavier Trucks and Buses

Heavier trucks and buses with a GVWR greater than 26,000 pounds have two primary ways to comply. Fleets can comply with the compliance schedule by engine model year or can use a phase-in option that is more flexible. Heavier trucks are required to meet the compliance schedule in Table VII-4. Fleets that comply with the schedule will install the best available PM filter on 1996 model year and newer engines and will replace the vehicle eight years later. Trucks with 1995 model year and older engines will be replaced starting in 2015. Replacements with a 2010 model year or newer engine meet the final requirements, but fleets can also replace with used trucks that have a future compliance date on the schedule. For example, a replacement with a 2007 model year engine complies until 2023. By 2023, all trucks and buses must have 2010 model year engines with few exceptions.

Table VI-4. Compliance Schedule for Vehicles with GVWR Greater than 26,000 Pounds

Engine Year	Requirement from January 1 st
Pre-1994	No requirements until 2015, then 2010 engine
1994-1995	No requirements until 2016, then 2010 engine
1996-1999	PM filter from 2012 to 2020, then 2010 engine
2000-2004	PM filter from 2013 to 2021, then 2010 engine
2005-2006	PM filter from 2014 to 2022, then 2010 engine
2007-2009	No requirements until 2023, then 2010 engine
2010	Meets final requirements

In addition, there is a phase-in option that allows fleets to decide which vehicles to retrofit or replace, regardless of engine model year. Fleets can comply by demonstrating they have met the percentage requirement each year as shown in Table VII-5. For example, by 2012, the fleet needs to have PM filters on 30 percent of the heavier trucks and buses in the fleet. This option counts 2007 model year and newer engines originally equipped with PM filters toward compliance and reduces the overall number of retrofit PM filters needed. Any engine with a PM filter regardless of model year is compliant until at least 2020. Beginning January 1, 2020, all heavier trucks and buses need to meet the requirements specified in Table VII-4.

Table VI-5. Phase-In Option for Vehicles with GVWR Greater than 26,000 Pounds

Compliance Date	Vehicles with PM Filters
January 1, 2012	30%
January 1, 2013	60%
January 1, 2014	90%
January 1, 2015	90%
January 1, 2016	100%

For more information on the On-Road Heavy-Duty Vehicle In-Use Regulation, go to:
<http://www.arb.ca.gov/msprog/onrdiesel/onrdiesel.htm>.

c. Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Residential and Commercial Solid Waste Collection Vehicle

ARB's Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Residential and Commercial Solid Waste Collection Vehicles (Solid Waste Collection Vehicle Regulation or SWCV Regulation) requires that fleets install BACT to reduce diesel PM, with a phased in compliance schedule that began in 2004 and ended on December 31, 2010. The regulation applies to owners of SWCVs or those diesel-fueled trucks over 14,000 pounds GVWR with 1960 through 2006 model year engines used to collect residential and commercial solid waste. An owner can be a private company operating independently or under contract to a city or county; or a city, county, state, or federal agency that directly operates refuse and recycling collection services.

BACT is an ARB-verified technology defined as one of four options:

- 1) An engine alone certified to the 2007 model year standard of 0.01 g/bhp-hr PM; for example, a new truck purchase beyond 2007.
- 2) An engine certified to the existing 0.01 g/bhp-hr PM standard that is then equipped with the most effective ARB-verified Diesel Emission Control Strategy (DECS) such as a diesel particulate filter or diesel oxidation catalyst; for example, replacing a 1990 truck engine with a 1994 engine plus DECS.
- 3) An alternative-fuel engine, such as one that runs on natural gas.
- 4) Any diesel or dual-fuel engine retrofitted with an ARB-verified DECS that reduced PM by the greatest amount possible for the particular engine and application.

For more information on the SWVC Regulation, go to:
<http://www.arb.ca.gov/msprog/SWCV/SWCV.htm>.

d. Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Vehicles Owned or Operated By Public Agencies and Utilities

ARB's Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Vehicles Owned and Operated by Public Agencies and Utilities (Fleet Rule for Public Agencies

and Utilities) requires that fleets reduce diesel PM by applying BACT to vehicles based on engine model year with a phased in compliance schedule that began in 2006 and ends 2016. The schedule is based on engine model year and county population for which the vehicle and the agency reside as shown in Table VII-6. The regulation applies to any municipality or utility that owns, leases, or operates an on-road diesel-fueled heavy-duty vehicle with a manufacturer's GVWR greater than 14,000 pounds powered by a 1960 through 2006 model year medium heavy-duty or heavy heavy-duty engine. The regulation does not provide an exemption based on the size of a fleet.

BACT requirements are met by any of the following:

- An engine certified to 0.01 g/bhp-hr PM or cleaner; or
- An engine retrofitted with the highest-level PM DECS.

In addition, public agencies and utilities can retire a vehicle (operate as a low-usage vehicle, scrap the engine, or sell/operate the vehicle out-of-state) and have it count towards the BACT requirement.

Table VI-6. Implementation Schedule for Public Agency and Utility Fleet Vehicles

Group	Engine Model Years	Applies to All Fleets		<i>Option for Fleets Located in a Low Population County³⁷ or Granted Low-Population County Status</i>	
		Percentage of Group to Use BACT	Compliance Deadline as of December 31	Percentage of Group to Use BACT	Compliance Deadline as of December 31
1 ³⁸	1960-1987	20%	2007	20%	2009
		60%	2009	40%	2011
		100%	2011	60%	2013
				80%	2015
				100%	2017
2	1988-2002	20%	2007	20%	2008
		60%	2009	40%	2010
		100%	2011	60%	2012
				80%	2014
				100%	2016
3	2003-2006 (includes dual-fuel and bi-fuel engines)	50%	2009	20%	2011
		100%	2010	40%	2012
				60%	2013
				80%	2014
				100%	2015
4	2007 and newer certified above 0.01 g/bhp-hr standard	100%	2012	20%	2012
				40%	2013
				60%	2014
				80%	2015
				100%	2016

For more information on the Fleet Rule for Public Agencies and Utilities, go to:
<http://www.arb.ca.gov/msprog/publicfleets/publicfleets.htm>.

2. Off-Road Vehicles

a. Emission Standards for New Off-Road Diesel Engines

Since the mid-1990s, new engine standards adopted by U.S. EPA and ARB have required new, off-road (or nonroad) engines to become progressively cleaner. In developing the new engine standards, ARB has worked closely with U.S. EPA to develop a harmonized federal and California program to more effectively control emissions from off-road vehicles. The emission standards are divided into four increasingly stringent levels (or Tiers), with the allowed emission level and effective dates varying with horsepower (hp). Until the mid-1990s, off-road diesel engines were not subject to any emission standards (commonly known as Tier 0 or “uncontrolled”). In

³⁷ A Low Population County is one of the following counties: Alpine, Amador, Calaveras, Colusa, Del Norte, Glenn, Inyo, Lake, Lassen, Mariposa, Mendocino, Modoc, Mono, Nevada, Plumas, San Benito, Sierra, Siskiyou, Sutter, Tehama, Trinity, Tuolumne, and Yuba. Other cities and counties may qualify for Low Population County status.

³⁸ An owner may not use Level 1 technology as classified pursuant to title 13, CCR, section 2700, as BACT on a Group 1 engine or vehicle.

1996 through 2000, the Tier 1 standards took effect for most engine categories. By 2006, all engine sizes were subject to Tier 2. Between 2006 and 2008, Tier 3 standards took effect for some hp groups. Tier 4 standards are divided into two stages: (1) interim, which begins between 2008 and 2012 for most engines, and (2) final, which is effective for all off-road engines by 2015. The final Tier 4 standards may require the use of advanced exhaust after-treatment technologies to control both PM and NOx.

In most cases, federal off-road regulations also apply in California, whose authority to set emission standards for new, off-road engines is limited. The federal Clean Air Act Amendments of 1990 preempt California's authority to control emissions from new farm and construction equipment under 175 hp and require California to receive authorization from U.S. EPA for controls over other off-road sources. Table VII-7 summarizes the ARB's emission standards for new, off-road diesel engines, in units of g/kWh (equivalent g/bhp-hr values are shown in parentheses).

Table VI-7. ARB Tier 1-4 Off-Road Diesel Engine Emission Standards in g/kWh (g/bhp-hr)

Engine Power	Tier	Year	CO	HC	NMHC+NOx	NOx	PM
kW < 8 (hp < 11)	Tier 1	2000-2004	8.0 (6.0)	-	10.5 (7.8)	-	1.0 (0.75)
	Tier 2	2005-2007	8.0 (6.0)	-	7.5 (5.6)	-	0.80 (0.6)
	Tier 4	2008 and later	8.0 (6.0)	-	7.5 (5.6)	-	0.40 (0.3)
8 ≤ kW < 19 (11 ≤ hp < 25)	Tier 1	2000-2004	6.6 (4.9)	-	9.5 (7.1)	-	0.80 (0.6)
	Tier 2	2005-2007	6.6 (4.9)	-	7.5 (5.6)	-	0.80 (0.6)
	Tier 4	2008 and later	6.6 (4.9)	-	7.5 (5.6)	-	0.40 (0.3)
19 ≤ kW < 37 (25 ≤ hp < 50)	Tier 1	2000-2003	5.5 (4.1)	-	9.5 (7.1)	-	0.80 (0.6)
	Tier 2	2004-2007	5.5 (4.1)	-	7.5 (5.6)	-	0.60 (0.45)
	Tier 4 / Interim	2008-2012	5.5 (4.1)	-	7.5 (5.6)	-	0.30 (0.22)
	Tier 4 / Final	2013 and later	5.5 (4.1)	-	4.7 (3.5)	-	0.03 (0.022)
37 ≤ kW < 56 (50 ≤ hp < 75)	Tier 1	2000-2003	-	-	-	9.2 (6.9)	-
	Tier 2	2004-2007	5.0 (3.7)	-	7.5 (5.6)	-	0.40 (0.3)
	Tier 3	2008-2011	5.0 (3.7)	-	4.7 (3.5)	-	0.40 (0.3)
	Tier 4 / Interim	2008-2012	5.0 (3.7)	-	4.7 (3.5)	-	0.30 (0.22)
	Tier 4 / Final	2013 and later	5.0 (3.7)	-	4.7 (3.5)	-	0.03 (0.022)
56 ≤ kW < 75 (75 ≤ hp < 100)	Tier 1	2000-2003	-	-	-	9.2 (6.9)	-
	Tier 2	2004-2007	5.0 (3.7)	-	7.5 (5.6)	-	0.40 (0.3)
	Tier 3	2008-2011	5.0 (3.7)	-	4.7 (3.5)	-	0.40 (0.3)
	Tier 4 / Phase-in	2012-2014	5.0 (3.7)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
	Tier 4 / Phase-out		5.0 (3.7)	-	4.7 (3.5)	-	0.02 (0.015)
	Tier 4 / or Alt NOx		5.0 (3.7)	0.19 (0.14)	-	3.4	0.02 (0.015)
	Tier 4 / Final	2015 and later	5.0 (3.7)	0.19 (0.14)	-	0.40	0.02 (0.015)
75 ≤ kW < 130 (100 ≤ hp < 175)	Tier 1	2000-2002	-	-	-	9.2 (6.9)	-
	Tier 2	2003-2006	5.0 (3.7)	-	6.6 (4.9)	-	0.30 (0.22)
	Tier 3	2007-2011	5.0 (3.7)	-	4.0 (3.0)	-	0.30 (0.22)
	Tier 4 / Phase-in	2012-2014	5.0 (3.7)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
	Tier 4 / Phase-out		5.0 (3.7)	-	4.0 (3.0)	-	0.02 (0.015)
	Tier 4 / or Alt NOx		5.0 (3.7)	0.19 (0.14)	-	3.4	0.02 (0.015)
	Tier 4 / Final	2015 and later	5.0 (3.7)	0.19 (0.14)	-	0.40	0.02 (0.015)

**Table VI-7. ARB Tier 1-4 Off-Road Diesel Engine Emission Standards
in g/kWh (g/bhp-hr) (continued)**

Engine Power	Tier	Year	CO	HC	NMHC+NOx	NOx	PM
130 ≤ kW < 225 (175 ≤ hp < 300)	Tier 1	1996-2002	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2003-2005	3.5 (2.6)	-	6.6 (4.9)	-	0.20 (0.15)
	Tier 3	2006-2010	3.5 (2.6)	-	4.0 (3.0)	-	0.20 (0.15)
	Tier 4 / Phase-in	2011-2013	3.5 (2.6)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
	Tier 4 / Phase-out		3.5 (2.6)	-	4.0 (3.0)	-	0.02 (0.015)
	Tier 4 / or Alt NOx		3.5 (2.6)	0.19 (0.14)	-	2.0	0.02 (0.015)
	Tier 4 / Final	2014 and later	3.5 (2.6)	0.19 (0.14)	-	0.40	0.02 (0.015)
225 ≤ kW < 450 (300 ≤ hp < 600)	Tier 1	1996	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2001	3.5 (2.6)	-	6.4 (4.8)	-	0.20 (0.15)
	Tier 3	2006	3.5 (2.6)	-	4.0 (3.0)	-	-
	Tier 4	2011-2014	3.5 (2.6)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
450 ≤ kW ≤ 560 (600 ≤ hp < 750)	Tier 1	1996-2001	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2002-2005	3.5 (2.6)	-	6.4 (4.8)	-	0.20 (0.15)
	Tier 3	2006-2010	3.5 (2.6)	-	4.0 (3.0)	-	0.20 (0.15)
	Tier 4 / Phase-in	2011-2013	3.5 (2.6)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
	Tier 4 / Phase-out		3.5 (2.6)	-	4.0 (3.0)	-	0.02 (0.015)
	Tier 4 / or Alt NOx		3.5 (2.6)	0.19 (0.14)	-	2.0	0.02 (0.015)
	Tier 4 / Final	2014 and later	3.5 (2.6)	0.19 (0.14)	-	0.40	0.02 (0.015)
kW > 560 (hp > 750)	Tier 1	2000-2005	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2006-2010	3.5 (2.6)	-	6.4 (4.8)	-	0.20 (0.15)
	Tier 4 / Interim	2011-2014	3.5 (2.6)	0.40 (0.30)	-	3.5 (2.6)	0.10 (0.075)
	Tier 4 / Final	2015	3.5 (2.6)	0.19 (0.14)	-	3.5 (2.6)	0.04 (0.03)
560 kW < GEN ≤ 900 kW	Tier 4 / Interim	2011-2014	3.5 (2.6)	0.40 (0.30)	-	3.5 (2.6)	0.10 (0.075)
	Tier 4 / Final	2015 and later	3.5 (2.6)	0.19 (0.14)	-	0.67 (0.50)	0.03 (0.022)
GEN > 900 kW	Tier 4 / Interim	2011-2014	3.5 (2.6)	0.40 (0.30)	-	0.67 (0.50)	0.10 (0.075)
	Tier 4 / Final	2015 and later	3.5 (2.6)	0.19 (0.14)	-	0.67 (0.50)	0.03 (0.022)

Source: Final Regulation Order, Off-Road Compression-Ignition Engines and Equipment (Article 4, Chapter 9, Division 3, title 13, CCR) at <http://www.arb.ca.gov/regact/offrdcie/frooal.pdf>

b. In-Use Off-Road Diesel Vehicle Regulation

ARB's Regulation for In-Use Off-Road Diesel Vehicles (Off-Road Regulation) was originally adopted in July 2007 and required vehicles to apply exhaust retrofits and accelerate turnover of fleets to newer, cleaner engines. The regulation applies to self-propelled diesel-fueled vehicles with engines 25 hp and greater that cannot be registered and licensed to drive on-road, although on-road water well drilling rigs, and all two-engine cranes are subject to the Off-Road Regulation. In addition, all two-engine on-road diesel-powered vehicles as well as two-engine vehicles that drive on-road (with the exception of two-engine sweepers) are subject to the Off-Road Regulation. Examples include loaders, crawler tractors, skid steers, backhoes, forklifts, and airport ground support equipment.

Amendments to the Off-Road Regulation adopted by the Board in December 2010 will delay the original compliance dates for all fleets by four years, making the first compliance deadline January 1, 2014, for large fleets (over 5,000 hp); January 1, 2017, for medium fleets (2,501 to 5,000 hp); and January 1, 2019, for small fleets (2,500 hp or less). In addition, the regulation amendments changed annual fleet average targets for

PM and NO_x, and now fleets will have only one annual fleet average target to meet based on their NO_x emissions. PM exhaust retrofits are now optional (not required), although if a fleet chooses to install PM exhaust retrofits, the Off-Road Regulation has a methodology that provides NO_x equivalence for a PM exhaust retrofit, for BACT and fleet average. If a fleet cannot meet the NO_x fleet average target, it must comply with the BACT requirements by cleaning up 4.8 to 10 percent of its fleet each year (4.8 in 2014 for large fleets). A fleet may satisfy the BACT requirements either by turnover or applying exhaust retrofits. Fleets with 500 hp or less can follow a simpler compliance method by phasing out their oldest, dirtiest vehicles starting in 2019. Tables VII-8 and VII-9 summarize the fleet average requirements.

Table VI-8. Large and Medium Fleet Targets for Use in Calculating Fleet Average Target Rates (g/bhp-hr)

Compliance Date, January 1 of Year	Targets for Each Maximum Hp Group							
	25-49 hp	50-74 hp	75-99 hp	100-174 hp	175-299 hp	300-599 hp	600-750 hp	>750 hp
2014 (large fleets only)	5.8	6.5	7.1	6.4	6.2	5.9	6.1	7.2
2015 (large fleets only)	5.6	6.2	6.7	6	5.8	5.5	5.6	6.8
2016 (large fleets only)	5.3	5.8	6.2	5.5	5.3	5.1	5.2	6.5
2017	5.0	5.4	5.5	4.9	4.7	4.5	4.6	6.0
2018	4.7	5.0	4.8	4.3	4.1	4.0	4.0	5.5
2019	4.4	4.6	4.1	3.7	3.5	3.4	3.4	5.0
2020	4.1	4.2	3.4	3.1	2.9	2.8	2.9	4.5
2021	3.8	3.8	2.7	2.5	2.3	2.2	2.3	4.0
2022	3.5	3.4	2.0	1.9	1.7	1.7	1.7	3.5
2023	3.3	3.0	1.4	1.3	1.5	1.5	1.5	3.4

Table VI-9. Small Fleet Targets for Use in Calculating Fleet Average Target Rates (g/bhp-hr)

	Targets for Each Maximum Hp Group							
Compliance Date, January 1 of Year	25-49 hp	50-74 hp	75-99 hp	100-174 hp	175-299 hp	300-599 hp	600-750 hp	>750 hp
2019	5.8	6.5	7.1	6.4	6.2	5.9	6.1	7.2
2020	5.6	6.2	6.7	6.0	5.8	5.5	5.6	6.8
2021	5.3	5.8	6.2	5.5	5.3	5.1	5.2	6.5
2022	5.0	5.4	5.5	4.9	4.7	4.5	4.6	6.0
2023	4.7	5.0	4.8	4.3	4.1	4.0	4.0	5.5
2024	4.4	4.6	4.1	3.7	3.5	3.4	3.4	5.0

Table VI-9. Small Fleet Targets for Use in Calculating Fleet Average Target Rates (g/bhp-hr) (continued)

	Targets for Each Maximum Hp Group							
Compliance Date, January 1 of Year	25-49 hp	50-74 hp	75-99 hp	100-174 hp	175-299 hp	300-599 hp	600-750 hp	>750 hp
2025	4.1	4.2	3.4	3.1	2.9	2.8	2.9	4.5
2026	3.8	3.8	2.7	2.5	2.3	2.2	2.3	4.0
2027	3.5	3.4	2.0	1.9	1.7	1.7	1.7	3.5
2029	3.3	3.0	1.4	1.3	1.5	1.5	1.5	3.5

Note that as of the date of this document, the December 2010 amendments have not been finalized. The Final Rulemaking Package was filed with OAL on October 28, 2011. OAL has until December 14, 2011, to make a determination. If OAL determines that the rulemaking satisfies the Administrative Procedure Act, then OAL files the regulation with the Secretary of State and the regulation usually becomes effective within 30 days.

The Off-Road Regulation includes a provision that may limit fleets to only adding vehicles that have a certain Tier engine or higher.

For more information on the In-Use Off-Road Diesel Vehicle Regulation, go to: <http://www.arb.ca.gov/msprog/ordiesel/ordiesel.htm>.

c. Fleet Requirements for Large Spark Ignition (LSI) Engine Forklifts and Other Industrial Equipment

The original Off-Road LSI Engine Regulation (LSI Regulation), which established new engine standards and test procedures for manufacturers of LSI engines, was approved by the Board on October 22, 1998, and became effective on November 8, 1999. On May 12, 2006, the ARB amended the LSI Regulation and additionally adopted fleet requirements for operators of in-use LSI fleets and verification procedures for manufacturers of LSI retrofit emission control systems. The amendments became effective on May 12, 2007.

The LSI fleet regulation applies to owners and operators of LSI engines 25 hp or greater used in forklifts, sweepers/scrubbers, industrial tugs, and airport ground support equipment – the four largest categories of LSI engine equipment. The 2006 rulemaking required manufacturers to certify their new LSI engines to a 2.0 g/bhp-hr HC+NO_x standard effective January 1, 2007, and a 0.6 g/bhp-hr standard effective January 1, 2010. The 2006 rulemaking also required operators of in-use fleets to achieve specific HC+NO_x fleet average emission level (FAEL) standards that become more stringent with fleet size and time. The standards are more stringent for forklifts than they are for non-forklift LSI equipment. The stringency of the standards reflects the differences in availability of retrofit devices for the four categories of in-use LSI equipment as well as the greater ability of large fleets to incorporate zero- and near-zero emission equipment into their operations. Operators of medium and large forklift fleets and operators of non-forklift fleets with more than three pieces of equipment must comply with the fleet average emission levels standards in Table VII-10 by the specified compliance dates.

Table VI-10. Fleet Average Emission Level Standards in g/kW-hr (g/bhp-hr) of HC+NO_x

Fleet Type	Initial Compliance Date		
	January 1, 2009	January 1, 2011	January 1, 2013
Large* Forklift Fleet	3.2 (2.4)	2.3 (1.7)	1.5 (1.1)
Medium** Forklift Fleet	3.5 (2.6)	2.7 (2.0)	1.9 (1.4)
Non-forklift Fleet	4.0 (3.0)	3.6 (2.7)	3.4 (2.5)

* "Large Fleet" means an operator's aggregated operations in California of 26 or more pieces of equipment.

** "Medium Fleet" means an operator's aggregated operations in California of 4 to 25 pieces of equipment.

Amendments to the LSI Regulation adopted by the Board in December 2010 will modify the limited hours of use provisions and broaden compliance extension flexibility. The LSI regulation would continue to require medium and large fleet operators to comply with the existing 2011 and 2013 FAEL standards requirements. Operators would achieve the FAEL standards requirements through either replacement with new or used zero- or near-zero emission equipment or retrofit of late model uncontrolled equipment. Small fleets would continue to be exempt from the regulation.

For more information on the LSI Fleet Regulation, go to:
<http://www.arb.ca.gov/msprog/offroad/orspark/orspark.htm>.

3. Portable Engines and Equipment

A portable engine 50 hp or greater must have a permit or registration to legally operate in California. A portable engine is an internal combustion engine that is designed and capable of being carried or moved from one location to another and does not remain at a single location for more than 12 consecutive months. Engines used to propel mobile equipment or a motor vehicle of any kind are not eligible for registration. A portable equipment unit is a portable piece of engine-driven equipment that is associated with, and driven solely by, a portable engine and emits pollutants over and above the emissions of the portable engine.

The ARB's Airborne Toxic Control Measure for Diesel PM from Portable Engines Rated at 50 Horsepower and Greater establishes the statewide Portable Equipment Registration Program (PERP), which is a voluntary program to register portable engines and portable engine-driven equipment such as air compressors, generators, concrete pumps, tub grinders, wood chippers, water pumps, drill rigs, pile drivers, rock drills, abrasive blasters, aggregate screening and crushing plants, concrete batch plants, and welders. Portable equipment registered in PERP may operate throughout the State without obtaining permits from any of California's 35 air districts. Portable engines and equipment that are exempt from ARB regulations may be subject to district permitting requirements. District permit requirements will vary, depending on the attainment status in the district. Some districts have implemented registration programs specifically for portable engines and equipment units. Owners of portable engines in these districts can register engines with the district by demonstrating that the engines meet specific emission rates. Some districts specifically exempt portable engines from permit requirements or have specific requirements for individual types of portable engines and/or equipment.

The portable engine ATCM (last amended February 19, 2011) requires portable diesel-fueled engines that have not been registered or permitted prior to January 1, 2010, to be certified to the most stringent emission standard contained in federal or California emission standards for off-road engines (see Table VII-7). Existing portable engines will eventually need to meet a more stringent PM emission standard in order to meet the ATCM fleet requirements by the applicable compliance dates, as shown in Table VII-11.

Table VI-11. PERP Fleet PM Emission Standard Requirements

Fleet Standard Compliance Date	Engines <175 hp (g/bhp-hr)	Engines 175 to 750 hp (g/bhp-hr)	Engines >750 hp (g/bhp-hr)
January 1, 2013	0.3	0.15	0.25
January 1, 2017	0.18	0.08	0.08
January 1, 2020	0.04	0.02	0.02

For more information on the Portable Diesel Engine ATCM, go to:
<http://www.arb.ca.gov/diesel/peatcm/peatcm.htm>.

C. Mitigation of Mobile Source Emissions Associated with Biorefineries

Mobile source emissions associated with biorefineries may be mitigated by obtaining emission reductions beyond those required by ARB's in-use diesel-fueled mobile source regulations and the use of other mitigation strategies. This section provides an overview of the options available to obtain surplus emission reductions and other strategies to mitigate air emissions from mobile sources associated with biorefineries.

1. Exceeding the Requirements of In-Use Diesel-Fueled Mobile Source Regulations

ARB's in-use diesel-fueled mobile source regulations reduce criteria pollutant, diesel PM, other TAC, and GHG emissions from mobile sources. Mitigation of mobile source emissions associated with biorefineries may be achieved through emission reductions that go beyond what is required by ARB's regulations. This may include early compliance, emission reductions from exempt fleets, or reductions greater than what is required. These reductions may be attained by:

a. Repower

Engine repower means the replacement of an existing engine with a new, cleaner certified engine instead of rebuilding the existing engine to its original specifications.

b. Retrofit

Retrofit means the installation of a verified emission control system on an existing engine. Examples include, but are not limited to, diesel particulate filters and catalyst systems.

c. New Purchases

New purchases refer to non-fleet modernization purchases of vehicles or equipment certified to optional, lower emission standards.

d. Fleet Modernization

Fleet modernization refers to the replacement of an older truck or piece of equipment that still has remaining useful life with a newer, cleaner truck or piece of equipment, and scrapping the old vehicle or equipment. Based on ARB's in-use on-road diesel vehicle regulations, this means the use of an engine meeting the 2010 model year emission standards, using an alternative-fuel engine, or other equivalent control method.

e. Alternative Fuel Use

Alternative fuel use means the use of fuels that have lower emissions than standard gasoline or diesel, such as hydrogen, CNG, LNG, and electricity.

2. Other Strategies to Mitigate Air Emissions

Table VI-1 provides other strategies to further mitigate air emissions from mobile sources associated with biorefineries. These include strategies to reduce diesel PM emissions, fugitive PM emissions, vehicle miles travelled (VMT), and exposure to sensitive receptors.

ARB staff reviewed the following documents to provide the list of potential strategies to mitigate mobile source emissions associated with biorefineries:

- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009);
- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007);
- California Department of Public Health's A Guide for Health Impact Assessment (2009);
- State and local CEQA guidelines;
- Draft and final EIRs for various industrial facilities; and
- ARB's Air Quality and Land Use Handbook (2005).

**Table VI-12. Other Strategies to Mitigate Air Emissions from Mobile Sources
Associated with Biorefineries**

	Mitigation Strategy	Description
1.	Reduce Diesel PM Emissions	<ul style="list-style-type: none"> • Require 2007 or newer model year engines in heavy-duty trucks that transport feedstocks or finished product. • Encourage the use of ultra-low emission switch locomotives and low emission line haul locomotives for the rail transport of raw material and finished fuel product. • Encourage the use of idle reduction devices to reduce emissions from idling locomotives used to transport raw material and finished fuel product. • Reduce emissions from idling vehicles by improving traffic flow by signal synchronization, or improved road infrastructure. • Use street sweepers that meet the BACT requirements of ARB's On-Road Heavy-Duty Diesel-Fueled Residential and Commercial Solid Waste Collection Vehicle regulation. • Maintain diesel engines and retrofit air pollution control device according to manufacturer's specifications.
2.	Reduce Fugitive PM Emissions	<ul style="list-style-type: none"> • Cover, wet all material, or maintain at least two feet of vertical space between the top of the load and the top of the trailer for all trucks hauling, dirt, sand, soil or other loose materials. • Wash off trucks and any equipment exiting unpaved roads onto paved roads using wheel washers, trackout devices, etc. • Limit or remove mud or dirt from adjacent public streets at the end of each workday. • Consider watering roads on days of moderate to high traffic to improve moisture and control PM. • Consider dust suppressants to control PM. • Cover, wet to limit visible dust emissions, and maintain at least six inches of freeboard space from the top of the container when materials are transported off-site. • Pave access roads at least 100 feet onto the site from main road. • Sweep streets once a day if visible soil materials are carried to adjacent streets (recommend water sweepers with reclaimed water). • Apply water three times daily, or non-toxic dust suppressant to all unpaved parking or staging areas or unpaved road surfaces. • Reduce traffic speeds on all unpaved roads to 15 miles per hour or less.
3.	Reduce Product (Raw and Finished) VMT	<ul style="list-style-type: none"> • Provide incentives for on-site fueling to minimize fuel export traffic.
4.	Reduce Exposure to Sensitive Receptors	<ul style="list-style-type: none"> • Consider co-located operations that consolidate truck traffic. • Develop routes for truck traffic that discourage use of roads in sensitive receptor neighborhoods. • Reduce vehicle miles traveled through adjacent residential property.

This Page Left Intentionally Blank

VII. OTHER CONSIDERATIONS AND FUTURE UPDATES TO THIS REPORT

This chapter provides a discussion of other factors to consider when determining the air quality impacts of a new or expanding biorefinery. These include the locations of communities that are already adversely impacted by air pollution, and applying other broader strategies at a facility, such as the use of more energy efficient processes. This chapter also discusses future updates to this Report.

A. Considerations for Highly Impacted Communities

Some communities in California experience higher exposures than others as a result of the cumulative impacts of air pollution from multiple sources – cars, trucks, trains, ships, off-road equipment, industrial and commercial facilities, and others. Achieving the goal of reducing emissions in localized communities involves identifying those communities that are disproportionately impacted by air pollution; performing assessments of cumulative emissions, exposure, and health risk on a neighborhood scale; and working with local air districts and stakeholders to address community concerns about air pollutant emissions, exposures, and health risks, and adopting strategies to reduce emissions.

ARB staff investigated whether methods have been developed to identify communities in California that are disproportionately impacted by air pollution from multiple sources. There are a few sources of information that have identified highly impacted communities in southern California and the San Francisco Bay Area based on air pollution indicators and socio-economic indicators. The southern California communities mapped are the result of an environmental justice screening method developed as part of a project-specific study funded by ARB. The project results include a 2010 report entitled “Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making” and have been published in the peer-reviewed *Journal of Environmental Research and Public Health* (May 2011).^{39, 40} The study investigators provided ARB with a relative ranking of census tracts in the South Coast Air Basin which integrates metrics of social vulnerability and indicators of air quality. The study investigators are currently developing maps for southern San Joaquin Valley (Fresno to Bakersfield), and they hope to eventually expand the tool to the whole State. Similarly, in the Bay Area, the Bay Area Air Quality Management District has identified six communities highly impacted by toxic air contaminants and high densities of vulnerable populations under its Community Air Risk

³⁹ Pastor, M., Morello-Frosch, R., Sadd, J. (2010, May 3). *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making*. Final Report: Contract Number #04-308. Retrieved from <http://www.arb.ca.gov/research/apr/past/04-308.pdf>

⁴⁰ Sadd J.L., Pastor M., Morello-Frosch R., Scoggins J., Jesdale B. Playing It Safe: Assessing Cumulative Impact and Social Vulnerability through an Environmental Justice Screening Method in the South Coast Air Basin, California. *International Journal of Environmental Research and Public Health*. 2011; 8(5):1441-1459. (<http://www.mdpi.com/1660-4601/8/5/1441/>)

Evaluation (CARE) Program.⁴¹ Information related to both of these programs is available to the public. This type of information should be considered in land-use and other decision-making processes, including in the siting or permitting consideration of a new or expanding biorefinery project should it be located within, or in close proximity to these areas. It should be noted that the southern California screening method and Bay Area CARE program are for specific, individual projects. Any analysis for highly impacted community purposes for any other projects should be evaluated on a case-by-case basis, as the ARB does not currently have an approved statewide method for identifying communities in California that are disproportionately impacted by air pollution. ARB staff will continue to monitor the development of screening tools for such purposes.

There are also various references stakeholders may wish to use during the project-specific analyses for new or expanding biorefinery projects that apply to localized community impacts. ARB released a report in 2005, Air Quality and Land Use Handbook: A Community Health Perspective to promote enhanced communication among land use agencies, districts, and sensitive receptors. It summarizes the air quality issues associated with emissions from industrial, commercial, and mobile sources of air pollution and provides recommendations to ensure that appropriate distances are maintained between sources of air pollution and sensitive receptors.

Other tools include:

- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007); and
- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009).

These tools are available on ARB's Biorefinery Guidance website at <http://www.arb.ca.gov/fuels/LCFS/bioguidance/bioguidance.htm>. ARB staff will provide updates to these documents as they become available.

B. Other Strategies to Minimize Air Emissions from Biorefineries

ARB staff recommends the following additional broad strategies to mitigate emissions from biorefineries:

- Use of onsite distributed generation (DG) and combined heat and power (CHP) systems in the form of fuel cells, microturbines, and other ultra-clean technologies.
- Where a site cannot use onsite DG or CHP, promote the use of pipeline injection of biogas, rather than on-site combustion of biogas as a strategy to reduce emissions of NO_x in areas that do not achieve the federal or State Ambient Air Quality Standards for ozone;

⁴¹ Bay Area Air Quality Management District. Community Air Risk Evaluation program. Information available online at: <http://www.baaqmd.gov/Divisions/Planning-and-Research/CARE-Program.aspx>.

- Promote the use of and explore economic and regulatory incentives for the maximum recovery of energy (particularly waste heat recovery) and other marketable by-products associated with biorefineries;
- Promote the use of and explore economic and regulatory incentives for cost effective and energy efficient emerging air pollution control strategies;
- Promote the use of and explore economic and regulatory incentives for fuel cells, microturbines, and other ultra-clean technologies that can be fueled by biogas; and
- Except for emergency purposes, minimize flaring of biogas or biofuel produced from biomass feedstocks.

C. Updates to Report

ARB staff's near-term update activities will focus on the distribution of new and updated BACT determinations, new source test results, new technologies, newly approved regulations (including test methods), and an updated list of existing biorefineries in California. This information will be posted to ARB's Biorefinery Guidance website at <http://www.arb.ca.gov/fuels/LCFS/bioguidance/bioguidance.htm>. ARB staff will send e-mail notifications to the LCFS listserve at ARB and the Bioenergy listserve at CEC when new information is posted to this website. ARB staff plans to provide these updates on an annual basis or as biorefinery project activity dictates.

In addition, to ensure the information provided in this Report stays current, ARB staff will perform periodic updates at intervals that correspond to the review periods set forth in the LCFS regulation. As part of these updates, staff will assess the geographic distribution of biorefineries in the State, and where appropriate, integrate additional mitigation measures for the purpose of protecting against air quality impacts that arise from the concentration or co-location of multiple biorefineries.

Future updates to this Report will also identify the source test methods that are required by a district to verify compliance with PM₁₀ permit limits for biomass-fired boilers to help ensure more consistency between the permitted emission limits and the source test methods used to verify compliance. ARB staff determined these methods were not necessarily comparable. For PM testing, some facilities used EPA Method 5 in conjunction with EPA Method 202, while other facilities used EPA Method 201A in conjunction with EPA Method 202. EPA Method 201A is an in-stack PM₁₀ measurement method and EPA Method 202 is a condensable PM measurement method used in conjunction with EPA Method 201 or 201A. However, EPA Method 5 is designated as a mass PM measurement method. One permit reviewed by ARB staff specifically stated that if EPA Method 5 is used, then it shall be assumed that 100 percent of PM is PM₁₀. ARB staff also plans to incorporate anticipated upcoming PM_{2.5} permit limits and corresponding source test method recommendations.

This Page Left Intentionally Blank

REFERENCES

1. ARB, 1990. California Environmental Quality Act Review Handbook for Local Air Pollution Control Agencies.
2. ARB, 1999. *Guidance for Power Plant Siting and Best Available Control Technology*, September 1999. Accessed 2010, from <http://www.arb.ca.gov/energy/powerpl/power.htm>
3. ARB, 2002. *Guidance for the Permitting of Electrical Generation Technologies*, July 2002. Accessed 2010, from <http://www.arb.ca.gov/energy/dg/guidance/guidelines.pdf>
4. ARB, 2005. *Air Quality and Land Use Handbook: A Community Health Perspective*. Accessed March 2010, from <http://www.arb.ca.gov/ch/landuse.htm>
5. ARB, 2007. *Staff Report: Initial Statement of Reasons for Proposed Regulation for Drayage Trucks*. Accessed March 2010, from <http://www.arb.ca.gov/regact/2007/drayage07/drayisor.pdf>
6. ARB, 2007. *Title 17, California Code of Regulations, Sections 93115 through 93115.15, Amendments to the Airborne Toxic Control Measure for Stationary Compression Ignition Engines*, effective October 18, 2007. Accessed 2010, from <http://www.arb.ca.gov/diesel/ag/documents/finalreg101807.pdf>
7. ARB, 2008. *July 2008 Biomass Report Permit Data Worksheet for Stockton RWCF, Sewage Digester Reciprocating Internal Combustion Engines*, Permit Nos. N-811-21-3, -22-3, and -23-3, Source Test Data from October 24, 2006.
8. ARB, 2009. *Staff Report: Initial Statement of Reasons for Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I*.
9. ARB, 2009. *Staff Report: Initial Statement of Reasons for Proposed Regulation to Implement the Low Carbon Fuel Standard Volume II*.
10. ARB, 2010. *Area Designations*. Accessed 2010, from <http://www.arb.ca.gov/desig/desig.htm>
11. ARB, 2010. *Distributed Generation Program*. Accessed 2010, from <http://www.arb.ca.gov/energy/dg/dg.htm>
12. ARB, 2010. *Proposed Screening Method for Low-Income Communities Highly Impacted by Air Pollution for AB 32 Assessments*
13. ARB, 2010. *Vapor Recovery Program*. Accessed 2010, from

<http://www.arb.ca.gov/vapor/vapor.htm>

14. Alabama Department of Environmental Management, 2008. *Synthetic Minor Operating Permit for Cello Energy, LLC*.
15. Alameda County Community Development Agency Planning Department, 2004. *Proposed Landfill Gas Conversion Project*.
16. Association of Environmental Professionals, 2010. *2010 California Environmental Quality Act (CEQA) Statute and Guidelines*. Accessed April 2010, from <http://www.califaep.org/CEQA2010>.
17. BAAQMD. *Evaluation Report for Golden Gate Petroleum*, Application No. 15965, Plant No. P18418, No Date.
18. BAAQMD. *Engineering Evaluation Report for Sonoma County Landfill*, Application No. 014593, No Date.
19. BAAQMD. *Engineering Evaluation Report for Whole Energy Fuels Corporation*, Application #16994, Plant #18791, No Date.
20. BAAQMD. *Permit to Operate for San Francisco South East Treatment Plant*, Plant No. 568, Unit No. S-10 – Reciprocating Engine, Cogeneration, 21 MMBtu/hr max, Natural gas, Digester gas, No Date.
21. BAAQMD. *Permit to Operate for Waste Management, Livermore, California*, Condition #18773 for Gas Turbines, Units S-6 and S-7, No Date.
22. BAAQMD. *Permit to Operate for Waste Management, Livermore, California*, Condition #19237 for Internal Combustion Engines, Units S-23 and S-24, No Date.
23. BAAQMD, 1999. *BAAQMD CEQA Guidelines. Assessing the Air Quality Impacts of Projects and Plans*. Accessed April 2010, from http://www.baaqmd.gov/~media/Files/Planning%20and%20Research/Plans/CEQA%20Guide/ceqa_guide.ashx
24. BAAQMD, 2004. *Regulation 8, Organic Compounds, Rule 18, Equipment Leaks*, September 15, 2004. Accessed 2010, from <http://www.baaqmd.gov/~media/Files/Planning%20and%20Research/Rules%20and%20Regs/reg%2008/rq0818.ashx>
25. BAAQMD, 2005. *Final Major Facility Review Permit for Waste Management of Alameda County*, Facility No. A2066, April 5, 2005. Accessed 2010, from http://www.baaqmd.gov/~media/Files/Engineering/Title%20V%20Permits/A2066/A2066_2005-04_minrev_01.ashx

26. BAAQMD, 2008. *Regulation 9, Inorganic Gaseous Pollutants, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*, July 30, 2008. Accessed 2010, from <http://www.baaqmd.gov/~media/Files/Planning%20and%20Research/Rules%20and%20Regs/reg%2009/rq0907.ashx>
27. BAAQMD, 2009. *BACT Guideline 96.1.3, IC Engine – Compression Ignition: Stationary Emergency, Non-Agricultural, Non-Direct Drive Fire Pump >50 BHP Output*, Table – Offroad Compression Ignition Engine Certification Standards, April 13, 2009.
28. BAAQMD, 2009. *Regulation 2, Permits, Rule 1, General Requirements*, March 4, 2009. Accessed 2010, from <http://www.baaqmd.gov/~media/Files/Planning%20and%20Research/Rules%20and%20Regs/new%20versions/rq0201.ashx>
29. BAAQMD, 2010. *Permit Handbook and BACT/TBACT Workbook on the Web*. Accessed 2010, from <http://hank.baaqmd.gov/pmt/bactworkbook/default.htm>
30. BAAQMD, 2010. *Permit to Operate for Blue Sky Bio-Fuels, LLC*, Plant No. 17937, Expiration Date: April 1, 2010.
31. Best Environmental, 2010. *Compliance Emissions Test Report for Gallo Cattle Company, Atwater, CA*, Two Digester Gas Fired Engines, N-1660-7-1 and N-1660-9-0, Test Date: January 28, 2010, Report Date: March 5, 2010.
32. Blue Sky Environmental, LLC, 2005. *Compliance Source Emissions Test Report Prepared for County of Sacramento, Dept. of Waste Management & Recycling, Kiefer Landfill Generating Plant*, Testing of the Landfill Gas Flare and 3 Engines, Test Dates: November 7-10, 2005, Report Date: December 30, 2005.
33. Bureau of Land Management, U.S. Department of the Interior, 2009. *National Environmental Policy Act (NEPA)*, last updated October 21, 2009. Accessed February 2011, from <http://www.blm.gov/wo/st/en/info/nepa.html>
34. CAPCOA, 2008. *Statewide Best Available Control Technology (BACT) Clearinghouse*. Accessed 2010, from <http://www.arb.ca.gov/bact/bact.htm>
35. CAPCOA Planning Managers, 2009. *Health Risk Assessments for Proposed Land Use Projects CAPCOA Guidance Document*.
36. California Department of Transportation, 2002. *Guide for the Preparation of Traffic Impact Studies*. Accessed April 2010, from <http://www.dot.ca.gov/hq/traffops/developserv/operationalsystems/reports/tisguid>

[e.pdf](#).

37. California Energy Commission, 2006. *Final Commission Decision: Los Esteros Critical Energy Facility II Phase 2*, CEC-800-2005-004-CMF, October 2006. Accessed 2010, from <http://www.energy.ca.gov/2005publications/CEC-800-2005-004/CEC-800-2005-004-CMF.PDF>
38. California Governor's Office of Planning and Research, 2010. *Planning, Zoning, and Development Laws*. Accessed March 2010, from <http://www.opr.ca.gov/index.php?a=planning/publications.html#pubs-P>.
39. City of Industry, 2007. *Puente Hills Intermodal Facility Draft EIR*. Accessed December 2007, from http://www.lacsd.org/info/waste_by_rail/phimf/phimf_deir.asp.
40. Council on Environmental Quality, Executive Office of the President, 2007. *A Citizen's Guide to the NEPA: Having Your Voice Heard*, December 2007. Accessed February 2011, from http://ceq.hss.doe.gov/nepa/Citizens_Guide_Dec07.pdf
41. DeMaris, Frank. San Joaquin Valley Air Pollution Control District. "Re: Valley BioEnergy Question." Email to Stephanie Kato. September 8, 2010.
42. Division of Air Quality of the Wyoming Department of Environmental Quality, 2006. *Application to Construct, Permit No. CT-4486*.
43. Garcia, Carlos. San Joaquin Valley Air Pollution Control District. "Re: BACT Guideline for Biomass." Email to Stephanie Kato. September 14, 2010.
44. Garcia, Carlos. San Joaquin Valley Air Pollution Control District. "Re: Boiler BACT Question." Email to Stephanie Kato. November 2, 2009.
45. Illinois Environmental Protection Agency, 2004. *Federally Enforceable Operating Permit for Adkins Energy, LLC I.D. No. 177802AAA*.
46. Illinois Environmental Protection Agency, 2004. *Construction Permit for Renewable Fuel of Carbondale, LLC I.D. No. 077015ACF*.
47. Illinois Environmental Protection Agency, 2006. *Construction Permit for Center Ethanol Company, LLC, I.D. No. 06030020*.
48. Illinois Environmental Protection Agency, 2006. *Title V – Clean Air Act Permit Program (CAAPP) Permit for Aventine Renewable Energy, Inc. I.D. No. 179060ACR*.

49. Illinois Environmental Protection Agency, 2007. *Construction Permit for Abengoa Bioenergy of Illinois, LLC, I.D. No. 1194965AAG*
50. Illinois Environmental Protection Agency, 2007. *Construction Permit for Ford Heights Ethanol, LLC, I.D. No. 031072AAB.*
51. Imperial County Air Pollution Control District, 2007. *Authority to Construct for Pacific Ethanol Brawley, LLC, Permit No: 3495.*
52. Iowa Department of Natural Resources, 2008. *Title V Operating Permit for ADM Corn Processing, Permit No. 08-TV-004.*
53. Iowa Department of Natural Resources, 2006. *Title V Operating Permit for ADM Corn Processing - Clinton, Permit No. 06-TV-007.*
54. Kleinfelder West, Inc. for the City of Hanford Community Development Department, 2007. *Draft Environmental Impact Report for the Great Valley Ethanol Project. SCH# 2007051088*
55. Krich, Ken, et al., for Western United Dairymen, 2005. *Biomethane from Dairy Waste: A Sourcebook for the Production and Use of Renewable Natural Gas in California*, July 2005.
56. Madera County, 2007. *Madera County Dairy Standards Project, Draft Environmental Impact Report SCH No. 2006081050.* Accessed April 2010, from http://www.madera-county.com/rma/archives/uploads/1215552234_Document_upload_madera_dairyfinal_eirweb.pdf.
57. Massachusetts Department of Environmental Protection, 2007. *BACT Guidance for Biomass Projects*, April 18, 2007. Accessed 2010, from <http://www.mass.gov/dep/air/laws/policies.htm>
58. Monterey Bay Unified Air Pollution Control District. *Permit to Operate 13109T Bio-Diesel Processing Facility – Gonzales.*
59. Norman, Ramon. San Joaquin Valley Air Pollution Control District. "Re: Gallo Permit & Source Test Results." Email to Stephanie Kato. September 21, 2010.
60. Oregon Department of Environmental Quality. *Air Contaminant Discharge Permit for Pacific Ethanol, Inc. Permit No. 25-0006*, December 22, 2005.
61. Pacific Municipal Consultants, for County of Imperial Planning & Development Services, 2006. *Administrative Draft Environmental Impact Report Volume I. For the Cilion Ethanol Plant.*

62. Pacific Municipal Consultants, for County of Imperial Planning & Development Services, 2007. Finding of Fact and Statement of Overriding Considerations for the Pacific Ethanol Final EIR. SCH# 2006061163.
63. Pacific Municipal Consultants, for County of Imperial Planning & Development Services, 2007. Imperial County Pacific Ethanol Production Facility. Final Environmental Impact Report. SCH No. 2006061163.
64. Point Environmental Services for the Port of Stockton, 2006. *Addendum to Port of Stockton West Complex Development Plan Environmental Impact Report: For Community Fuels Biodiesel Production Facility Lease Approval.*
65. Quad Knopf, Inc., Lee N. Smith, Esq., Stoel Rives, LLP, David R. Albers, Esq., Wild, Carter & Tipton, Inc., for Tulare County Board of Supervisors, 2001. *Administrative Draft Environmental Impact Report. Hilarides Dairy, SCH #99-101079.*
66. Renewable Fuels Association, 2010. Biorefineries Locations. Accessed September 2010, from <http://www.ethanolrfa.org/bio-refinery-locations/>
67. Reese-Chambers Systems Consultants, Inc., 2008. Letter to Mr. Richard Wales, Air Quality Engineer, Antelope Valley AQMD, Application Nos. 00009287 through 00009303 for BlueFire Ethanol, September 24, 2008.
68. San Diego County Air Pollution Control District, 2004. *Source Test History for Gas Recovery Systems Inc., Santee, California*, Permit No. 980112, Solar Centaur 40 Landfill Gas Turbine, Test Date: November 23, 2004.
69. San Diego County Air Pollution Control District, 2005. *Permit to Operate Display Form for Gas Recovery Systems Inc., Santee, California*, Permit No. 980112, ID No. 6257 A, Landfill Gas Turbine, June 21, 2005.
70. San Diego County Air Pollution Control District, 2006. *Source Test History for Gas Recovery Systems Inc., Santee, California*, Permit No. 980112, Solar Centaur 40 Landfill Gas Turbine, Test Date: December 1, 2006.
71. SJVAPCD, 2002. *Guide for Assessing and Mitigating Air Quality Impacts*, Accessed March 2010, from <http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf>
72. SJVAPCD, 2004. *Authority to Construct for Pacific Ethanol Madera LLC, Project No: C-1031341.*
73. SJVAPCD, 2004. *Authority to Construct for Phoenix Bio Industries LLC, Project No: S-1040738.*

74. SJVAPCD, 2004. *Review of Source Test for Madera Power, LLC*, Memorandum to Source Test File, regarding a review of the report submitted by Advanced Air Testing, Test Date: August 25, 2004, Memorandum Date: November 15, 2004.
75. SJVAPCD, 2005. *Authority to Construct Application Review for Calgren Renewable Fuels, LLC*, Project No: S-1051224, July 20, 2005.
76. SJVAPCD, 2005. *Permit to Operate for Thermal Energy Development Corporation, LTD*, Permit Unit No. N-1026-1-6, Expiration Date: July 31, 2005.
77. SJVAPCD, 2005. *Rule 4455, Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants*, April 20, 2005. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4455.pdf>
78. SJVAPCD, 2006. *Authority to Construct for Cilion, Inc.*, Project No: N-1062063.
79. SJVAPCD, 2006. *Authority to Construct for Pacific Ethanol Stockton, LLC*, Project No: N-1054197.
80. SJVAPCD, 2006. *Draft Environmental Impact Report for the Van Der Kooi Dairy SCH # 2006011107*. <http://www.valleyair.org/notices/Docs/priorto2008/11-28-06/DEIR.pdf>
81. SJVAPCD, 2007. *Application Review for American Biodiesel*, Project No. N-1061971, June 4, 2007.
82. SJVAPCD, 2007. *Application Review for Authority to Construct for Crimson Renewable Energy*, Project No. 1064848, August 1, 2007.
83. SJVAPCD, 2007. *Authority to Construct for Great Valley Ethanol, LLC*, Project No: C-1070368.
84. SJVAPCD, 2007. *Determination of Compliance Emission Testing for Phoenix Bio Industries LLC*, Project No: 07123.2C.
85. SJVAPCD, 2007. *Pacific Ethanol Madera LLC, 2007 Emission Compliance Test Report*.
86. SJVAPCD, 2007. *Permit to Operate for AES Delano Inc.*, Permit Unit S-75-6-15, Expiration Date: August 31, 2007.
87. SJVAPCD, 2007. *Rule 4565, Biosolids, Animal Manure, and Poultry Litter Operations*, March 15, 2007. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4565.pdf>

88. SJVAPCD, 2007. *Rule 4703, Stationary Gas Turbines*, September 20, 2007. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4703.pdf>
89. SJVAPCD, 2008. *Authority to Construct for Fiscalini Farms & Fiscalini Dairy*, Permit No. N-6311-9-1, December 17, 2008.
90. SJVAPCD, 2008. *Rule 4306, Boilers, Steam Generators, and Process Heaters – Phase 3*, October 16, 2008. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4306.pdf>
91. SJVAPCD, 2008. *Rule 4307, Boilers, Steam Generators, and Process Heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr*, October 16, 2008. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4307.pdf>
92. SJVAPCD, 2008. *Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters with a Total Rated Heat Input Greater than 5.0 MMBtu/hr*, October 16, 2008. Accessed 2010, from <http://www.valleyair.org/rules/currntrules/r4320.pdf>
93. SJVAPCD, 2009. *CEQA Air Quality Handbook. A Guide for Assessing the Air Quality Impacts for Projects subject to CEQA Review*, Accessed March 2010, from http://www.slcleanair.org/pdf/CEQA_Handbook_Final_draft_2009_v03.pdf
94. SJVAPCD, 2009. *Gaseous Emissions Test Results Summary and PM10 Emissions Results Summary for Rio Bravo Fresno*, pages excerpted from compliance source test report including permit limits, Test Date: November 11, 2009.
95. SJVAPCD, 2009. *Notice of Preliminary Decision – Authority to Construct, Project Number N-1083593, Authority to Construct Application Review*, Musco Olive Products, Application No. N-1145-7-0, September 21, 2009.
96. SJVAPCD, 2009. *Notice of Preliminary Determination of Compliance (PDOC), Facility: San Joaquin Solar 1 & 2 (08-AFC-12), Project Number: C-1090203, Determination of Compliance Evaluation*, October 8, 2009.
97. SJVAPCD, 2010. *BACT Clearinghouse*. Accessed 2010, from <http://www.valleyair.org/busind/pto/bact/bactchidx.htm>
98. SJVAPCD, 2010. *Notice of Preliminary Decision – Authority to Construct, Facility Number: N-8095, Project Number: N-1094135, for Valley Bio-Energy, LLC, BACT Guideline and BACT Analysis*, July 12, 2010.
99. SJVAPCD, 2012. *Permit to Operate for Gallo Cattle Company*, Permit Unit: N-1660-9-2, Expiration Date: September 30, 2012.

100. SCEC, 2005. *Criteria Pollutant Test Result Summary, City of San Bernardino, Engine #1 and Engine #2*, Test Dates: November 1-4, 2005.
101. SCEC, 2006. *Criteria Pollutant Test Result Summary for LES Kiefer Landfill, Unit #4 and Unit #5*, Test Dates: May 11-12, 2006.
102. SCEC, 2006. *Criteria Pollutant Test Result Summary for Kiefer Landfill, Unit #1, Unit #2, and Flare*, Test Dates: October 25-26, 2006.
103. SCEC, 2007. *Criteria Pollutant Test Result Summary for Kiefer Landfill, Unit #1 and Unit #3*, Test Dates: January 30-31, 2007.
104. SCEC, 2007. *Criteria Pollutant Test Result Summary for Kiefer Landfill, Unit #1, Unit #2, Unit #4, Unit #5, and Flare*, Test Dates: March 27-30 and April 4, 2007.
105. Science Applications International Corporation for the County of Ventura Planning Division, 2009. *Simi Valley Landfill and recycling Center Expansion Project, Public Draft Environmental Impact Report*.
106. Solvay Chemicals, Inc., 2005. *Technical Publication: Trona-Sodium Sesquicarbonate*, Accessed 2010, from <http://www.solvaychemicals.us/static/wma/pdf/6/8/5/3/trona-SodiumSesquicarbonate.pdf>
107. SCAQMD. *Best Available Control Technology Guidelines, Part B – LAER/BACT Determinations for Major Polluting Facilities*, Section I – AQMD LAER/BACT Determinations, Section II – Other LAER/BACT Determinations, Various Dates. Accessed 2010, from <http://www.aqmd.gov/bact/BACTGuidelines.htm>
108. SCAQMD. *Permit to Construct Evaluation for Inland Empire Regional Composting Authority*, Facility ID No. 139808, No Date.
109. SCAQMD, 1997. *Rule 1134, Emissions of Oxides of Nitrogen from Stationary Gas Turbines*, August 8, 1997. Accessed 2010, from <http://www.aqmd.gov/rules/reg/reg11/r1134.pdf>
110. SCAQMD, 1997. *Permit to Operate for L.A. County Sanitation District, Puente Hills Landfill*, Facility ID 025070, Permit No. F5294, Application No. 312961, February 12, 1997.
111. SCAQMD, 1998. *Rule 431.1. Sulfur Content of Gaseous Fuels*, June 12, 1998. Accessed 2010, from <http://www.aqmd.gov/rules/reg/reg04/r431-1.pdf>
112. SCAQMD, 2002. *Permit to Construct Evaluation for Inland Empire Utilities Agency (IEUA) at Chino Basin Desalter No. 1*, Facility ID No. 128776, Application No. 388037, January 31, 2002.

113. SCAQMD, 2003. *Permit to Construct for Lomita Rail Terminal, LLC*, Facility ID No. 136475, Application No. 415524, December 2, 2003.
114. SCAQMD, 2003. *Rule 1133.2, Emission Reductions from Co-Composting Operations*, January 10, 2003. Accessed 2010, from <http://www.aqmd.gov/rules/reg/reg11/r1133-2.pdf>
115. SCAQMD, 2005. *Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. A reference for Local Governments Within the South Coast Air Quality Management District*, Accessed March 2010, from <http://www.aqmd.gov/prdas/aqguide/index.html>
116. SCAQMD, 2006. *Permit to Construct for Apollo Energy III*, Bowerman Landfill, Facility ID 146113, Application No. 449437, March 30, 2006.
117. SCAQMD, 2006. *Permit to Operate for San Bernardino City Municipal Water Department*, Cogeneration System No. 1, Facility ID No. 11301, Permit No. F83304, Application No. 431476, July 20, 2006.
118. SCAQMD, 2006. *Permit to Operate for San Bernardino City Municipal Water Department*, Cogeneration System No. 2, Facility ID No. 11301, Permit No. F83305, Application No. 431477, July 20, 2006.
119. SCAQMD, 2006. *Permit to Construct and Operate Experimental Research Project for International Environmental Solutions Corporation*, Facility ID 122334, Application Nos. 448619 and 448620, March 7, 2006.
120. SCAQMD, 2006. *Preliminary Determination of Compliance (PDOC) for Walnut Creek Energy Project (05-AFC-2)*, Engineering Analysis / Evaluation, October 27, 2006. Accessed 2010, from http://www.energy.ca.gov/sitingcases/walnutcreek/documents/government/2006-10-31_SCAQMD_PDOC.PDF
121. SCAQMD, 2007. *Permit to Construct*, Application No. 464569, Owner: Noil Energy Group.
122. SCAQMD, 2008. *Best Available Control Technology Guidelines – Part D: BACT Guidelines for Non-Major Polluting Facilities*, October 3, 2008. Accessed 2010, from <http://www.aqmd.gov/bact/PartD-10-3-2008.pdf>
123. SCAQMD, 2008. *Rule 461, Gasoline Transfer and Dispensing*, March 7, 2008. Accessed 2010, from <http://www.aqmd.gov/rules/reg/reg04/r461.pdf>
124. SCAQMD, 2008. *Rule 1146, Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*,

- September 5, 2008. Accessed 2010, from
<http://www.aqmd.gov/rules/reg/reg11/r1146.pdf>
125. SCAQMD, 2008. *Rule 1146.1, Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters*, September 5, 2008. Accessed 2010, from
<http://www.aqmd.gov/rules/reg/reg11/r1146-1.pdf>
 126. SCAQMD, 2009. *Permit to Construct and Operate Experimental Research Operations for Orange County Sanitation District*, Facility ID 017301, Application No. 491468, February 19, 2009.
 127. SCAQMD, 2009. *Permit to Construct for West Colton Rail Terminal LLC*, Facility ID No. 161211, Application No. 486861, November 10, 2009.
 128. SCAQMD, 2010. *Interim Report on Technology Assessment for Biogas Engines Subject to Rule 1110.2*, July 9, 2010. Accessed 2010, from
<http://www.aqmd.gov/hb/2010/July/100725a.htm>
 129. SCAQMD, 2010. *Rule 1110.2, Emissions from Gaseous- and Liquid-Fueled Engines*, July 9, 2010. Accessed 2010, from
<http://www.aqmd.gov/rules/reg/reg11/r1110-2.pdf>
 130. State of Idaho Department of Environmental Quality, 2006. *Initial Permit to Construct for Idaho Ethanol Processing, LLC, I.D. No. 027-00096*.
 131. State of Georgia Department of Natural Resources, 2007. *Air Quality Permit for Range Fuels Biofuels, Permit No. 2869-283-0005-S-01-0*.
 132. State of Idaho Department of Environmental Quality, 2008. *Permit to Construct for Pacific Ethanol Magic Valley, LLC, I.D. No. 031-00032*.
 133. State of Louisiana Department of Environmental Quality, 2008. *Permit, Verenium Biofuels Louisiana LLC, Jennings Ethanol Plant, Agency Interest No.: 3245*.
 134. The Avogadro Group, LLC, 2006. *Source Test Report, Initial Compliance and Relative Accuracy Test Audit: Sierra Pacific Industries McBurney Boiler, Lincoln, California*, Test Dates: February 9-10, 2006, Report Date: March 28, 2006.
 135. The Avogadro Group, LLC, 2007. *2007 Emission Compliance and RATA Report, AES Delano, Inc.*, for Permit Numbers: S-75-6-15 and S-75-11-12, Test Dates: June 12-14, 2007, Report Date: July 31, 2007.
 136. Tupac, Charles. South Coast Air Quality Management District. "Re: Action Items: Air Quality Guidance Document for Siting Biorefineries Workgroup

- Meeting #10.” Email to Stephanie Kato. August 25, 2010.
137. Tupac, Charles. South Coast Air Quality Management District. “Re: Action Items: Air Quality Guidance Document for Siting Biorefineries Workgroup Meeting #10.” Email to Stephanie Kato. September 1, 2010.
 138. Tupac, Charles. South Coast Air Quality Management District. “Re: Action Items: Air Quality Guidance Document for Siting Biorefineries Workgroup Meeting #10.” Email to Stephanie Kato. September 14, 2010.
 139. U.S. Department of Energy. *Biomass Program Student Glossary*. From: http://www1.eere.energy.gov/biomass/student_glossary.html.
 140. U.S. Department of Energy, 2007. *Final Environmental Assessment. Construction and Operation of a Proposed Cellulosic Ethanol Plant, Range Fuels, Inc. Treutlen County, Georgia*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/ea1597.htm>
 141. U.S. Department of Energy, 2008. Prepared by ENSR & AECOM. *Environmental Assessment and Notice of Wetlands Involvement. Construction and Operation of a proposed Lignocellulosic Biorefinery, POET Project LIBERTY, LLC. Emmetsburg, Iowa*. Accessed April 2010, from <http://nepa.energy.gov/documents/EA-1628.pdf>
 142. U.S. Department of Energy, 2009. *Supplemental Environmental Assessment and Notice of Wetlands Involvement. Construction and Operation of a Proposed Cellulosic Ethanol Plant, Range Fuels Soperton Plant, LLC (formerly Range Fuels Inc.) Treutlen County, Georgia*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/documents/EA-1647.pdf>
 143. U.S. Department of Energy. *Program Feedstock Composition Glossary*. From: http://www1.eere.energy.gov/biomass/feedstock_glossary.html
 144. U.S. Department of Energy, Golden Field Office, 2003. *Chariton Valley Biomass Project. Final Environmental Assessment and Finding of No significant Impact*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/ea1475.htm>
 145. U.S. Department of Energy, Golden Field Office, 2005. *Environmental Assessment. Design and Construction of a Proposed Fuel Ethanol Plant, Jasper County, Indiana*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/ea1517.htm>
 146. U.S. Department of Energy, Golden Field Office, 2008. *Mitigation Action Plan for the Final Environmental Assessment, Notice of Wetland Involvement, and finding of No Significant Impact for the Construction and Operation of a Lignocellulosic Biorefinery, POET Project Liberty, LLC., Emmetsburg, Iowa*. Accessed

April 2010, from http://www.gc.doe.gov/NEPA/documents/EA-1628_POET_MAP.pdf

147. U.S. Department of Energy, Golden Field Office, 2009. *Draft Environmental Impact Statement for the Proposed Abengoa Biorefinery Project near Hugoton, Stevens County, Kansas*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/1133.htm>
148. U.S. Department of Energy, Savannah River Operations Office, 2008. *Environmental Assessment for Biomass Cogeneration and Heating Facilities at the Savannah River Site*. Accessed April 2010, from <http://www.gc.doe.gov/NEPA/documents/EA-1605.pdf>
149. U.S. EPA, 1987. *Title 40, Code of Federal Regulations, Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*, Source: 52 FR 11429, Adopted April 8, 1987, and subsequently amended. Accessed 2010, from http://edocket.access.gpo.gov/cfr_2004/julqtr/pdf/40cfr60.110b.pdf
150. U.S. EPA, 1998. *AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources*, Section 1.4: Natural Gas Combustion, Final Section, July 1998. Accessed 2010, from <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf>
151. U.S. EPA, 2010. *RACT/BACT/LAER Clearinghouse (RBLC)*. Accessed 2010, from <http://cfpub.epa.gov/RBLC/>
152. U.S. EPA, 2010. *The Green Book Nonattainment Areas for Criteria Pollutants*. Accessed 2010, from <http://www.epa.gov/air/oagps/greenbk/index.html>
153. URS, 2005. *Source Test Report, Digester Gas Fuel Cell, Palmdale Water Reclamation Plant*, Test Date: January 19, 2005, Report Date: February 18, 2005.
154. URS, 2006. *Source Test Report, ICE No. 1, Puente Hills Landfill*, SCAQMD Permit to Construct A/N 394362, Test Dates: July 11 and 14, 2006, Report Date: November 2, 2006.
155. URS, 2007. *SCAQMD Permit to Construct Compliance Source Test Report, Internal Combustion Engine, Frank R. Bowerman Landfill Liquid Natural Gas Facility*, SCAQMD Permit to Construct A/N 449437 and 449438, Test Dates: July 5-6, 2007, Report Date: August 10, 2007.
156. URS, 2007. *Source Test Results, ICE Unit A, June 2007, Olinda Landfill*, SCAQMD Permit to Construct A/N 414941, Test Date: June 13, 1007, Report Date: August 10, 2007.

157. Valla, Arthur. Bay Area Air Quality Management District. "Re: Tentative Date – Air Quality Guidance Document for Siting Biorefineries Workgroup Meeting." Email to Lea Yamashita, Sheraz Gill, Jorge DeGuzman, and Jay Chen. June 23, 2010.
158. Ventura County Air Pollution Control District, 2005. *Summary of Results for Waste Management, Simi Valley Landfill*, page excerpted from compliance source test report including permit limits, I.C. Engines #1 and #2, March 17, 2005.
159. Ventura County Air Pollution Control District, 2007. *Permit to Operate for Hill Canyon Waste Water Treatment Plant*, Number 07854, 500 kW Cogeneration System, Valid April 1, 2007 to March 31, 2008.